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December 18, 2015

Via Email
Original via Mail

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI)

Application for its Common Equity Component and Return on Equity (ROE) for 2016 (the Application)

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 1

On October 2, 2015, FEI filed the Application referenced above. In accordance with Commission Order G-177-15 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc: Commission Secretary
Registered Parties (e-mail only)

1. Reference: Exhibit B-1, Appendix B, Pages 45 and 49

> The ex-post market risk premium, provides a longer view of the investment horizon and may provide a better estimate of how the market will perform over a very long investment horizon, but is not sensitive to changes in interest rates and the prevailing economic environment. The ex-post market risk premium is calculated based on the arithmetic average of historical risk premia over the longest period for which data is available. Duff & Phelps calculates the risk premium for the U.S. as far back as 1926 and it calculates the Canadian risk premium as far back as 1919, from Morningstar Direct data.

> I have tested my market risk premium estimates by conducting a regression analysis on long Canada bond yields and annual market risk premiums calculated by Morningstar Ibbotson through 2011; and by Duff & Phelps thereafter. As can be seen in Exhibit JMC-6, I have isolated the effects of the global financial crisis in 2008 as an anomalous event that did not align with the normal relationship between treasury yields and market risk premiums. I have set this period aside by assigning a dummy variable to it. My analysis yielded a statistically significant value at the 85 percent confidence level, and in my opinion is informative of the relationship between bond yields and market risk premiums. Note that the coefficient for 30-year bond yields is negative 1.11, such that a negative change in the bond yield results in an almost equal increase in the market risk premium - evidence

1.1 Is Morningstar Ibbotson referenced on page 49 the same source of information as the Morningstar Direct data referenced on page 45?

Response:

Generally, yes. Morningstar Ibbotson discontinued its printing of the Morningstar/Ibbotson International Cost of Capital Reports, which contained Canadian risk premia data, in 2013 (including data through December 2012). In 2014, Duff and Phelps began publishing Canadian risk premia data for the year ended December 2013. Duff and Phelps makes the following disclosures in connection with the risk premia data they have provided.

The ERPs in Data Exhibit 1:

- *Were calculated using the same general data sources that were used to calculate the equity risk premia previously published in the Morningstar/Ibbotson International Equity Risk Premia Report.*
- *Were calculated using the same general methodologies that were used to calculate the equity risk premia previously published in the Morningstar/Ibbotson International Equity Risk Premia Report.*[1]

So though the data may not be identical to that used in the Morningstar/Ibbotson International Equity Risk Premia Report, in every instance, they are generally the same.

1.2 Please provide the results for the regression analysis if the 2008 period was not set aside.

Response:

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	10.2085509	6.738042772	1.515061753	0.138254	-3.44402	23.86112
Canada Long Bond	-0.745785974	0.799968377	-0.932269318	0.357241	-2.36668	0.875104

Please refer to Attachment 1.2 for the regression.

1.3 Why was information calculated by Morningstar Ibbotson used through 2011 and then switched to Duff and Phelps?

Response:

Though Morningstar Ibbotson data was available through 2012, Mr. Coyne used the Duff and Phelps data, published in 2014, which included data through December 2013, for both 2011 and

[1] Duff and Phelps, 2015 International Valuation Handbook: Guide to Cost of Capital, Market Results through December 2014 and March 2015; United States Long-Horizon Equity Risk Premia in U.S. Dollars, Data Exhibit 1, International Equity Risk Premia (ERPs).

2012 returns. As indicated above, the Morningstar/Ibbotson publication was discontinued in 2013 and it appears that its data was transferred to Duff and Phelps under some sort of sale or agreement commencing with the 2014 publication by Duff and Phelps.

1.4 Could James Coyne have utilized either all Morningstar Ibbotson information or all Duff and Phelps information? Please explain why or why not.

Response:

No. Morningstar/Ibbotson discontinued publishing Canadian Equity Risk Premia in 2013. Mr. Coyne did not purchase the final 2013 Morningstar/Ibbotson International Cost of Capital publication, but instead relied on the Duff and Phelps 2014 International Valuation Handbook for Canadian equity risk premia after 2011.

1.4.1 If yes, please recalculate the regression analysis using: (a) all Morningstar information; and (b) all Duff Phelps information.

Response:

The new Duff and Phelps International Valuation Handbook only publishes the history of single year risk premium for the current year and on 5 year intervals. Therefore, Duff and Phelps does not have a complete history of the annual market risk premia to perform the regression entirely from Duff and Phelps data. Please refer to Attachment 1.4.1 for an example of the Duff and Phelps format.

2. Reference: Exhibit B-1, Appendix B, Page 21 and Page 23

Generally, current capital market conditions are not dissimilar to what they were in June 2012. Capital markets continue to recover from the global economic crisis of 2008-2009, but at a slower than expected pace and have shown little change from when FEI last filed its GCOC evidence in 2012. Bond yields have remained low and utility bond spreads have remained somewhat elevated, with no significant movements since June 2012.

Table 3: TSX Market Indicators

		June 2012 [1]	August 2015
S&P/ TSX Composite			
	Price Index	11,597	13,859
	Earnings	$789.00	$802.38
	Dividends	$365.80	$433.98
	Trailing P/E	14.70X	20.28X
	Dividend Yield	3.20%	3.13%
	Long Term Growth Rate	3.36%	13.82%
	D/Y Ratio	1.9X	2.1X
S&P/ TSX 60			
	Price Index	664	815
	Earnings	$48.00	$50.38
	Dividends	$20.90	$25.46
	Trailing P/E	13.80X	18.81X
	Dividend Yield	3.10%	3.12%
	Long Term Growth Rate	3.01%	14.47%
	Forward P/E [2]	12.60X	15.94X
	Forward Earnings Yield (E/P) [3]	7.94%	6.27%
	D/Y Ratio	1.8X	2.1X
10-year Canada Bond Yield		1.70%	1.49%

Notes:
[1] Per Direct Evidence of Kathy McShane in BC GCOC Proceeding (August 2012) at 32.
[2] Forward P/E ratio is 12/31/2015 Bloomberg Estimate.
[3] Forward Earnings Yield is calculated by dividing 1 by the Forward P/E
Source: Data from Bloomberg

2.1 What, if any, is the significance of the sizeable differences in the Trailing P/E and the Long Term Growth Rate between 2012 and August 2015 with respect to the analysis?

Response:

The substantial increases in the Trailing P/E between 2012 and 2015 indicate that investors see greater growth opportunities both in the market overall and in utility shares than was the case in 2012. After several years of post-recession expansion, values for equities have been driven to higher levels, although we have seen some retrenchment over the course of 2015. The increase in growth rates reflects greater optimism across the economic spectrum in terms of future earnings growth, both for the broader index and utilities.

3. Reference: Exhibit B-1, Appendix B, Page 45

> **i. <u>Risk Free Rate</u>**
>
> My CAPM analysis relies on the 2016 through 2018 average Consensus Economics forecast of the Canadian 10-year government bond (shown previously in Table 2, and repeated below in Table 4) and adds the historical spread between 10-year and 30-year government debt.[61] This period has been chosen to match the period when FEI's rates are most likely to be in effect.

3.1 Please provide further justification for the statement that the period was chosen to 'match the period when FEI's rates are most likely to be in effect'.

<u>Response:</u>

Mr. Coyne has observed that the Commission precedent is to set the ROE and capital structure of the regulated companies for a three-five year period. Though Mr. Coyne acknowledges that this practice is not set in stone, judging by past BCUC decisions, Mr. Coyne presumes that rates established as a result of this Application will most likely be in effect for a number of years. As Table 2, in Mr. Coyne's testimony demonstrates, bond yields are expected to increase substantially over the next several years. As such, the very low interest rates prevalent today are not expected to be sustained through the rate period. Since cost of capital determinations are sometimes dependent on the level of bond yields, (i.e., CAPM, risk premium approach), it is appropriate to consider both the period for which rates will be in effect, and to also reflect the longer term outlook of typical utility investors.

4. Reference: Exhibit B-1, Appendix B, Pages 45, 46 and 47

> The ex-post market risk premium, provides a longer view of the investment horizon and may provide a better estimate of how the market will perform over a very long investment horizon, but is not sensitive to changes in interest rates and the prevailing economic environment. The ex-post market risk premium is calculated based on the arithmetic average of historical risk premia over the longest period for which data is available. Duff & Phelps calculates the risk premium for the U.S. as far back as 1926 and it calculates the Canadian risk premium as far back as 1919, from Morningstar Direct data.
>
> The shortcoming of using such a long horizon equity risk premia is it tends to be low in a low interest rate environment and high in a high interest rate environment. Said another way, the longer the averaging period, the less responsive the market risk premium will be to current market conditions, as additional data has less weight in the average as time goes on. Since both the U.S. and Canadian economies have enjoyed a prolonged low interest rate environment, which seems to have accelerated downwards in recent months, it should be expected that the historical arithmetic average will understate the current market risk premium.
>
> Because of this, I have incorporated a forward-looking risk premium (ex-ante) estimate to mitigate the inability of the long term historical average to respond to changes in capital market conditions. My ex-ante risk premium is based on capital market conditions on August 31, 2015, using forward projections of the return on the relevant market indices less the risk-free rate. I have used a forecast of the 30-year bond yield in my calculation of the ex-ante risk premium, which arguably lowers and moderates the risk premium result by the difference between the 30-year bond yield at August 31, 2015 (2.23%) and the forecast bond yield I have used to calculate the forward-looking market risk premium of (3.68%).

4.1 Please confirm that the incorporation of a forward looking premium adjusts for current market conditions, such as interest rates, that would otherwise be lost in a longer historical averaging period?

Response:

Mr. Coyne confirms that the incorporation of a forward looking premium adjusts for current market conditions and the effect that such conditions have on the market risk premium. Longer historical averaging periods are not responsive to changes in capital market conditions and in periods of low interest rates and high estimated growth, long term averages of the market risk premium will understate estimated returns.

4.1.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 1.4.1.

5. Reference: Exhibit B-1, Appendix B, Pages 61 and 62

> In its May 2013 Generic Cost of Capital Decision, the BCUC reiterated eight primary factors that Terasen Gas Inc. (now FEI) had identified in its 2009 Cost of Capital proceeding that had exerted significant influence on FEI's long term risk profile. The same factors were identified as having still been relevant in the last GCOC proceeding. Those factors were:[98]
>
> 1) Provincial Government climate and energy policies;
> 2) The effect of aboriginal rights issues;
> 3) The competitive position of natural gas relative to electricity;
> 4) Percentage of new construction being captured by [FEI];[99]
> 5) Natural gas vs. Electricity in high density housing;
> 6) The impact of Alternative Energy Sources on [FEI];[100]
> 7) Changes in demand related to fuel switching; and
> 8) Use of natural gas per customer account.
>
> I have reviewed the influence of these factors on FEI's long term risk profile and note that the above list of factors remains relevant today and continues to impact the company's risk profile.

5.1 Please confirm that the BCUC considered the above factors in its 2013 Generic Cost of Capital Decision.

Response:

Confirmed. The listed factors were originally identified in the BCUC 2009 GCOC proceeding, and carried over for consideration in the 2013 GCOC proceeding. The Commission noted in its 2013 GCOC Decision, that it was combining consideration of factors 4 and 5 related to the capture rate of new construction and the energy choice for high density housing for consideration under the more general heading of "Customer Growth". The Commission also noted that factors 7 and 8, related to use per customer and fuel switching related demand were also considered under the general heading of "Market Demand and Throughput" in the 2013 proceeding. The Commission added two new areas for consideration in the 2013 proceeding that were not specifically designated as one of the 8 factors in the 2009 proceeding, "Supply Risk" and "Regulatory Risk".

6. Reference: Exhibit B-1, Appendix B, Page 62

capital proceedings for FEI. The business risk factors I have examined are listed below in the order addressed:

1) Operating Risks
2) Gas Supply and Infrastructure Risk
3) Gas Price Levels and Volatility
4) Volume/Demand Risk
5) Political and Regulatory Risk

6.1 Please confirm or otherwise explain that it is appropriate to assess a company including value for those areas in which the company or industry faces very low risk relative to other companies/industries.

Response:

Mr. Coyne confirms that a comparative risk analysis among like-risk peer companies selected for use in a proxy group provides information on where within the range of risk the target company falls, inclusive of areas of both higher or lower risk. Mr. Coyne finds limited value in comparing the risks of FEI to low risk companies in other industries as there is sufficient information on companies in the same industry, and this avoids the problem of interpreting risks across both companies and industries.

6.2 Please confirm that typical business risk may also include such risks as competitive alternatives, industry risk, management risk and others?

Response:

Confirmed, though Mr. Coyne cautions that categorical groupings used to describe specific business risk factors vary depending on the source and purpose of the risk assessment. Mr. Coyne notes that his initial screening criteria and his comparative business risk analysis identifies the relevant business risks for FEI and the proxy group companies. Specifically, Mr. Coyne has considered "competitive alternatives" in his evaluation of volume/demand risk; and has considered "industry risk" as it pertains to each of the risk categories he has designated. Mr. Coyne has essentially evaluated management risk through his initial screening criteria; if a company was poorly managed, it would ultimately be reflected in its credit rating and would not have satisfied the credit rating screen. The presumption is that all large publicly-held energy utilities with an investment grade credit rating are competently managed, and if a company was poorly managed, it would be reflected in its credit rating.

Reviewing the Moody's credit rating criteria, Mr. Coyne notes that quality of the management team is considered in their ratings assessment. Specifically, Moody's states:

> *Other Rating Considerations*
>
> *Moody's considers other factors in addition to those discussed in this report, but in most cases understanding the considerations discussed herein should enable a good approximation of our view on the credit quality of companies in the regulated electric and gas utilities sector. Ratings consider our assessment of the quality of management, corporate governance, financial controls, liquidity management, event risk and seasonality. The analysis of these factors remains an integral part of our rating process.*

Similarly, S&P separately evaluates the quality of management and governance as a modifying factor that can move the stand-alone credit rating by one or more notches. S&P states,

> *The analysis of management and governance addresses how management's strategic competence, organizational effectiveness, risk management, and governance practices shape the company's competitiveness in the marketplace, the strength of its financial risk management, and the robustness of its governance. The range of management and governance assessments is: 1, strong; 2, satisfactory; 3, fair; and 4, weak. Typically, investment-grade anchor outcomes reflect strong or satisfactory management and governance, so there is no incremental benefit. Alternatively, a fair or weak assessment of management and governance can lead to a lower anchor. Also, a strong assessment for management and governance for a weaker entity is viewed as a favorable factor, under the criteria, and can have a positive impact on the final SACP outcome. For the full treatment of management and governance, see "Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers," published Nov. 13, 2012.*

Quality of management may be reflected in the financial metrics and competitive business risk profile of the rated entity which are primary determinants of the credit rating, and both ratings agencies provide for an upwards or downwards adjustment to the credit rating if management is determined to be an incremental factor in its rating determination.

6.2.1 If confirmed, please provide a list of the types of risks that might normally accrue to a business and would be considered in evaluating the risk of the company.

Response:

Please refer to Mr. Coyne's risks identified on p. 62 of his Direct testimony, and the response to CEC IR 1.6.2.

6.3 Please provide an assessment of FEI's 'management risk'.

Response:

Mr. Coyne has assessed management risk through his initial credit rating screen by requiring a credit rating of BBB+ or above (Baa1 or above for Moody's) for consideration in the proxy group. It is presumed that FEI and all of the proxy group companies that share this range of credit ratings also share a similar level of management competence. Please also refer to Mr. Coyne's response to CEC IR 1.6.2.

7. Reference: Exhibit B-1, Appendix B, Pages 62 and 63; and Appendix C page 4

> **1. <u>Operating Risks</u>**
>
> It should also be noted that BC recognizes 285 different aboriginal First Nations, Bands and Tribal Councils in the province, which may lead to additional regulatory processes to allow proper recognition of these groups' rights in regulatory proceedings. This impacts the Company's business risk profile by adding the potential for protracted regulatory and political proceedings which could stymie or delay project plans and adds a layer of regulatory and administrative burden to utility operations.

> previous periods, the 2014 PBR Decision included some additional regulatory uncertainty and risk, although the broader regulatory constructs that supported FEI's characterization of regulatory risk in 2012 remain in place. FEI has thus assessed its overall regulatory risk as being similar to what it was in 2012, with the potential to be higher over the term of PBR.

7.1 Please specify which regulatory and political proceeding costs are flowed through to customers under PBR and which costs are incurred under the O&M formula.

<u>Response:</u>

FEI notes that Mr. Coyne was not referring to uncertainty regarding the recovery of regulatory proceeding costs in his statement on page 63 of Appendix B, but rather to the extent of proceedings, associated delays to projects and the associated regulatory and administrative burden to the utility.

FEI's third party costs for the Commission's regulatory proceedings, and third party political costs associated with CPCN projects (such as public consultation and First Nations engagement), are generally recovered through deferral accounts from ratepayers, once approved by the Commission. Other regulatory and political costs, including internal staff resources and any third party costs associated with regular capital projects, are included in formula O&M or capital during the term of the PBR, with variances from the formula amount subject to earnings sharing with ratepayers.

7.2 Please confirm, or otherwise explain that under Cost of Service, costs related to regulatory and political proceedings are recovered from customers in O&M.

Response:

The treatment of these costs is the same as described in the response to CEC IR 1.7.1 under PBR or Cost of Service, with the exception that any amounts that are included in formula O&M or capital under PBR, are instead forecast in O&M or capital under Cost of Service. To the extent the amounts are included in the forecast for the test year(s) under Cost of Service, they are recovered from customers in O&M or capital.

8. Reference: Exhibit B-1, Appendix B, Page 65

Table 13: Key Economic Indicators (2014-2035 Projections)[104]

Economic Indicator	NL	ALB	BC	NS	ONT	PEI	QC
GDP Growth	0.8%	2.0%	2.1%	1.1%	2.1%	1.4%	1.6%
Population Growth	(0.2%)	1.4%	1.0%	0.0%	1.1%	0.4%	0.7%
Employment Growth	(0.6%)	1.2%	0.9%	(0.1%)	1.0%	0.2%	0.5%
Household Disposable Income	1.8%	4.0%	3.9%	2.4%	3.8%	2.8%	3.0%
Retail Sales	2.3%	3.7%	3.7%	2.8%	3.7%	3.3%	3.2%
Housing Starts	(7.7%)	(1.3%)	(0.8%)	(3.5%)	1.2%	(3.3%)	(2.1%)

8.1 Were economic indicators for US states considered?

Response:

U.S. economic indicators were not presented in Mr. Coyne's testimony but specific economic indicators were considered for each service territory represented in the U.S. proxy group. Specifically, for the U.S. companies, Mr. Coyne commented on population growth, per capita income growth, new customer annual growth, and in some cases natural gas penetration rates for new and existing housing (where available). This information is presented in the Proxy Group risk templates for each U.S. proxy company, found in Mr. Coyne's Appendix A.

8.1.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 1.8.1.

8.1.2 If yes, please provide the US economic indicators that were considered.

Response:

Please refer to the response to CEC IR 1.8.1.

9. Reference: Exhibit B-1, Appendix B, Page 66

> As FEI notes in its risk evidence, the expansion of natural gas fired power demand due to the retirement of coal plants in combination with new exports of LNG, and the potential addition of new gas demand from three proposed methanol plants in Washington and Oregon, could result in a capacity shortage on Spectra's T-South pipeline to move supply to facilities in southern BC and the U.S. Pacific Northwest.[107] This capacity constraint would increase volatility and natural gas prices. While pipeline expansions are an option, they require several years to complete. Based on the projected addition of natural gas demand in BC and the Pacific Northwest and considering the availability of pipeline capacity to accommodate the incremental demand, it is my view the risks associated with pipeline infrastructure will continue to grow as incremental natural gas demand materializes.

9.1 Please provide the projected additions of natural gas demand in BC and the Pacific Northwest on which the above statements rely.

<u>Response:</u>

Please refer to Figures D5 (page 14) and C4 (page 17) and Appendix A, pp. 20 – 26 of Attachment 9.1.

9.2 Please provide the projected pipeline capacity figures on which the above statements rely.

<u>Response:</u>

Please refer to Attachment 9.1 provided in response to CEC IR 1.9.1, Appendix A, pp. 20 – 26.

9.3 Please provide quantification for the size of the increase in risk that is anticipated.

Response:

Please refer to the responses to CEC IRs 1.9.2 and 1.9.3, and Mr. Coyne directs attention to pp. 24 and 26 of the Appendix A provided in Attachment 9.1 provided in response to CEC IR 1.9.1 for the "Supply Surplus/Shortfall" for the Expected and Accelerated demand scenarios. These referenced pages provide the magnitude of the potential supply shortfalls, however, Mr. Coyne has not provided a quantitative assessment of how this risk might impact the determination of FEI's allowed return. Mr. Coyne has qualitatively assessed this risk for FEI on p. 78 of his direct testimony. Qualitative risk factors do not easily lend themselves to quantitative assessments, but rather are considered as inputs to the overall risk assessment, in which individual risk factors, such as gas price levels and volatility, must be afforded weight depending on the implications and magnitude of the risk for the company in accordance with the judgment of the person developing the assessment.

9.4 Over what period of time is the project risk expected to materialize. Please provide timeframes with quantification.

Response:

Please refer to the responses to CEC IRs 1.9.2 and 1.9.3. The timeframe of expected risk evolves progressively over the 2015 – 2024 period.

10. Reference: Exhibit B-1, Appendix B, Pages 66 and 67

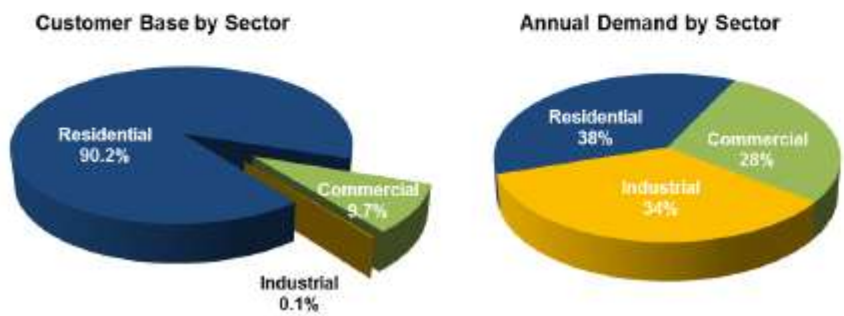
> **3. <u>Gas Price Levels and Volatility</u>**
>
> Natural gas price volatility is an important determinant of gas distribution risk since natural gas prices compete directly with electricity in BC, and FEI's industrial customers are sensitive to fluctuations in their energy prices. Natural gas is a much more volatile
>
> commodity in BC than electricity since the commodity cost of natural gas is market based while electricity in BC is primarily cost-based due to large provincially-owned hydro generation.

10.1 Does gas compete with electricity for all customers?

<u>Response:</u>

The following response addresses CEC IRs 1.10.1.1 through 1.10.2.1.

Natural gas competes with electricity for certain types of end-uses in homes and businesses. As discussed in the Company's most recent Long Term Resource Plan filed on March 25, 2014[2], the FEI customer base includes over 945,000 customers, consisting predominantly of residential customers that account for approximately 90% of the overall customer base (see Figure below). However, on an annual demand basis, there is a more even split between the residential, commercial, and industrial groups.



There are numerous end use applications for natural gas so it is difficult to provide an exhaustive list of the customers and end-uses where gas competes with electricity. Typically, the competition between the two energy forms in residential settings relates to the production of heating, cooling or hot water as well as cooking, drying and/or decorative uses. In general, the

[2] FortisBC Energy Utilities (FEU) Long Term Resource Plan, page 39.

main forms of competition in the commercial sector are similar to residential, namely heating, water heating, cooling and cooking.

Industrial applications requiring heating, cooling, and cooking may compete with electricity. Industrial applications where natural gas typically wouldn't compete with electricity include waste treatment and incineration, drying and dehumidification, food processing, and industrial boilers. Applications where natural gas is used as a feedstock for the manufacturing of chemicals and products wouldn't compete with electricity.

10.1.1 If not, please explain for which customer groups electricity does not compete with natural gas.

Response:

Please refer to the response to CEC IR 1.10.1.

10.2 Does gas compete with electricity in all end-uses?

Response:

Please refer to the response to CEC IR 1.10.1.

10.2.1 If no, please provide the end-uses which do not compete with natural gas.

Response:

Please refer to the response to CEC IR 1.10.1.

10.3 Please provide an estimate of the elasticity for FEI's industrial customers.

Response:

This response addresses CEC IRs 1.10.3 through 1.10.5. FEI does not have data on cross-price elasticity between natural gas and electricity. FEI's 2014 LTRP identified that own-price elasticity for natural gas is low and suggested values of -0.2 for residential and -0.5 for commercial and industrial customers[3]. The following source references are cited in the 2014 LTRP:

> Residential price elasticity data is from http://www.nrel.gov/docs/fy06osti/39512.pdf, although http://www.eia.gov/oiaf/analysispaper/elasticity/pdf/tbl.pdf suggests that the long term price elasticity is higher.[4]

The following document contains additional information on natural gas and electricity price elasticity and suggests that the values may have increased somewhat:

> http://www.sustainableprosperity.ca/sites/default/files/publications/files/The%20Likely%20Effect%20of%20Carbon%20Pricing%20on%20Energy%20Consumption%20in%20Canada.pdf.

Please note that the elasticity estimate presented for commercial and industrial customers has a high level of aggregation. In these markets, the responsiveness of demand to price may vary greatly depending on factors such as the ability to hedge against price volatility by industrial customers, degree of fuel substitution possibilities, reduction in production levels, etc.

10.4 Please provide the elasticity for FEI's commercial customers.

Response:

Please refer to the response to CEC IR 1.10.3.

3 FEI 2014 Long Term Resource Plan, Appendix B-3, page 10.
4 Footnote No. 3, Page 6 of Appendix B-3, 2014 LTRP.

10.5 Please provide the elasticity for FEI's residential customers.

Response:

Please refer to the response to CEC IR 1.10.3.

10.6 Please provide the elasticity for transportation customers.

Response:

For the purpose of this response FEI assumes that "transportation customers" means customers that use natural gas as a transportation fuel. FEI is not aware of any studies that have determined price elasticity or cross-price elasticity values for transportation fuels and so is unable to provide the requested information.

Despite the current fuel price spread between conventional fuels (i.e.,diesel) and natural gas that is helping to encourage fuel switching to natural gas, financial incentives are still needed to bring down the payback period for new capital investments in natural gas vehicles.

10.7 Please provide a forecast of the expected price of electricity over the next 30 years, with a discussion of the assumptions included in the forecast.

Response:

FEI has interpreted this question as referring to expected electricity rates in BC as charged by BC Hydro, rather than market electricity prices, given that the preamble to the question discusses electricity in BC being primarily cost-based due to large provincially-owned hydro generation.

According to the BC Government's 10 Year Plan released in November 2013, BC Hydro's electricity rate increases have been set according to the following plan[5]:

- As per Order in Council 096, dated March 5, 2014, Special Direction No. 6 to the British Columbia Utilities Commission, Section 3(c):

[5] https://news.gov.bc.ca/stories/10-year-plan-means-predictable-rates-as-bc-hydro-invests-in-system.

> *"the commission must confirm the authority's rates for F2015 and F2016 as set out in Appendix B to this direction;"*

which resulted in increases to BC Hydro's rates of approximately 9% and 6% for F2015 and F2016 respectively.

- The BC Utilities Commission will set increases for the following three years within caps of four per cent, 3.5 per cent and three per cent; and
- In the final five years of the plan, rates will be set by the BCUC and actions by government and BC Hydro will ensure increases remain low and predictable.

The existing 5% rate rider will remain in place. Therefore, based on this plan, FEI expects BC Hydro's rates for the next 3 years to be as follows:

Schedule 1101 - Residential Service

BC Hydro Forecasted Rates [2]	*Current Rates* F2016	F2017	Increase	F2018	Increase	F2019	Increase
Basic Charge per day	$ 0.1764	$ 0.1835	4%	$ 0.1899	3.5%	$ 0.1956	3.0%
Step 1 - First 675 kW.h per month [3]	$ 0.0797	$ 0.0829	4%	$ 0.0858	3.5%	$ 0.0884	3.0%
Step 2 Additional kW.h per month [3]	$ 0.1195	$ 0.1243	4%	$ 0.1286	3.5%	$ 0.1325	3.0%

Notes:

[2] *As per Order in Council 097 dated March 5, 2014, Special Direction No. 7 to the British Columbia Utilities Commission, Section 9 (1).*

[3] *Rates are exclusive of the applicable deferral account rate rider.*

FEI does not know what BC Hydro rates will be beyond F2019 as these will be determined in future BC Hydro applications to the BCUC.

10.8 Please provide a discussion of sensitivities with respect to the expected price of electricity over the next 30 years.

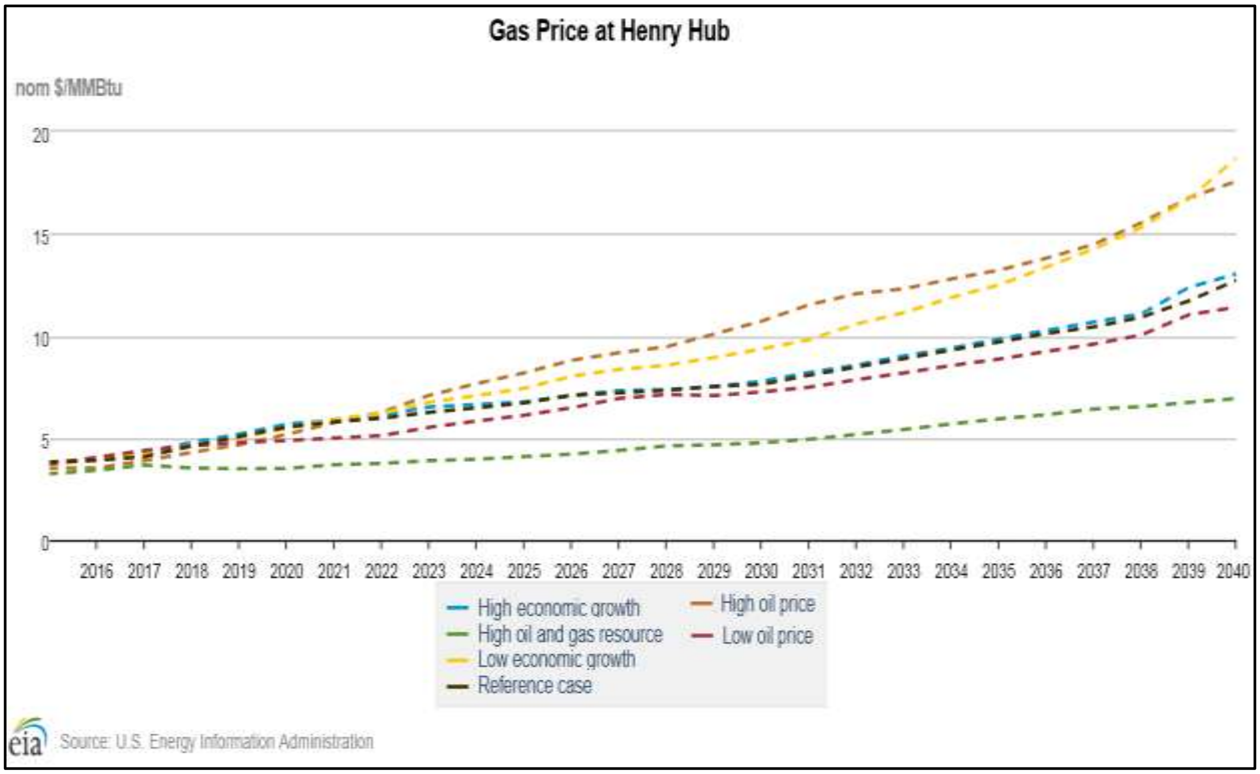
Response:

Please refer to the response to CEC IR 1.10.7.

10.9 Please provide a forecast of the expected price of natural gas over the next 30 years.

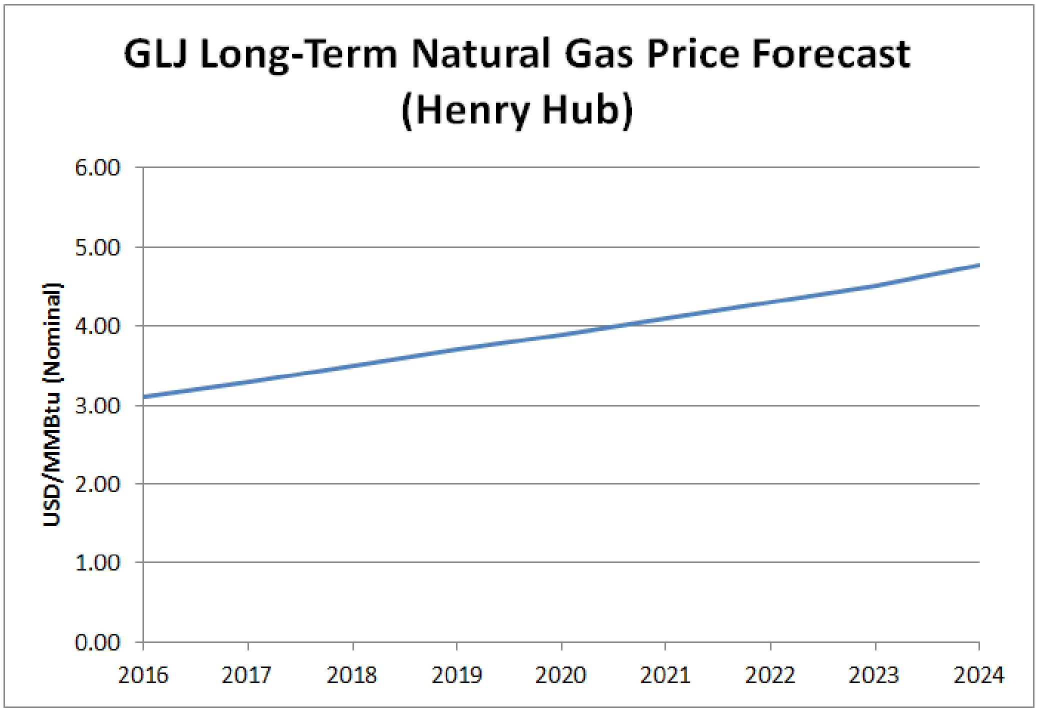
Response:

FEI does not produce its own natural gas price forecasts but relies on third party forecasts.. The following figure illustrates the latest long-term natural gas price forecast for Henry Hub out to 2040 from the U.S. Energy Information Administration (EIA) Annual Energy Outlook 2015 report.



The EIA produced a reference case of natural gas prices over the next 25 years with five alternative cases based on low and high oil prices, low and high economic growth, and high oil and gas resources.

GLJ Petroleum Consultants also produces a long-term natural gas price forecast. The following figure shows the latest GLJ forecast as of October 1st, 2015 out to 2024.



10.10 Please provide a discussion of sensitivities with respect to the expected price of natural gas over the next 30 years.

Response:

Please refer to the response to CEC IR 1.10.9.

10.11 Please provide an overview and estimate of the costs that a residential customer might incur transitioning from natural gas to electricity.

Response:

The preamble to this question discusses the sensitivities of industrial customers to natural gas price volatility and does not comment on the transition of residential customers from natural gas to electricity due to short-term price spikes. Residential customers are inelastic and normally use their equipment until the end of its useful life. The upfront capital cost consideration is more relevant to FEI's challenges in attracting new customers, as developers and builders who are the primary decision makers for choosing between electric and natural gas appliances are not directly influenced by operational costs considerations.

A residential customer transitioning from natural gas to electricity might incur two types of costs:

1. The cost to remove the natural gas equipment; and
2. The cost of the purchase and installation of electrical heating equipment.

The cost to remove natural gas equipment is dependent upon the unique circumstances of the residential customer in question. FEI does not have and is unable to provide this costing data.

The cost to purchase and install space heating and water heating equipment (for both natural gas and electric options) is also dependent upon many factors that are specific to the individual residential customer requirements such as brand name and technical specifications of the equipment, the building size and type or location of the building. As provided on page 33, Table C-6 of Appendix C, for a new medium sized, 3000 square foot single-family dwelling in the Lower Mainland, the cost to purchase and install electric space heating and water heating is estimated to be around $4,435 and $1,000 respectively.

FEI cannot provide any estimates for retrofit projects in older homes as they might be impacted by updates to building codes and other factors that are specific to each project.

10.12 Please provide an estimate of the costs that a commercial customer might incur transitioning from natural gas to electricity.

Response:

There are 180 different commercial sectors served by FEI, each with their own use of gas and own energy needs. Each commercial customer would need to determine first if electricity can meet their energy requirements and then must undertake its own analysis to determine the cost to transition from natural gas to electricity. FEI is therefore unable to answer the question as posed.

11. Reference: Exhibit B-1, Appendix B, Page 67

> FEI contracts for approximately 138 PJ of base load and seasonal supply to serve its customers.[108] The majority of natural gas production in northern BC has served the provincial and Pacific Northwest markets via the Westcoast Spectra System, the remainder is sourced in Alberta and transported on TransCanada.[109] FEI holds approximately 35.5 PJs of storage capacity consisting of two peak shaving LNG facilities and off-system capacity contracted with third parties.[110] In the past, FEI engaged in price risk management to limit exposure to gas price volatility, which included hedging instruments, such as natural gas derivatives. In July 2011, the BCUC ordered FEI to suspend the majority of its hedging activities (except for winter Sumas/AECO basis swaps). All hedges expired in 2014.
>
> 108 Fortis Inc. 2014 Annual Information Form For the Year Ended December 31, 2014 (February 18, 2015) at pp. 19-20.
> 109 Ibid.
> 110 Ibid.

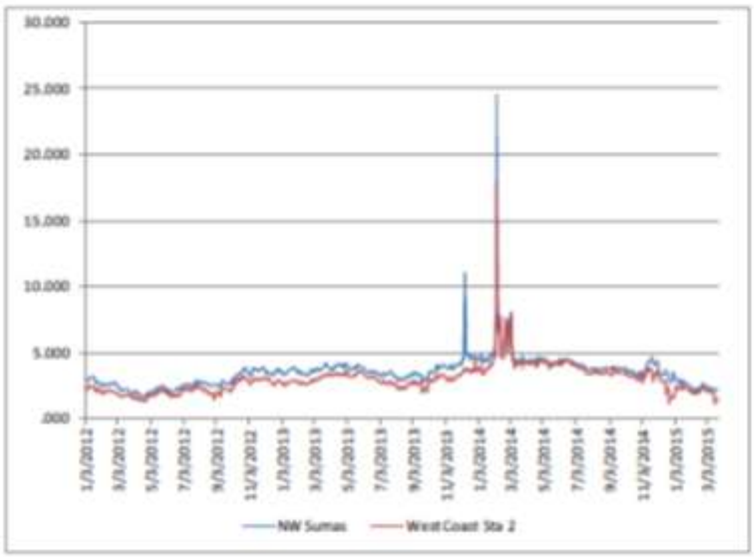
11.1 Please provide the Fortis Inc. 2014 Annual Information Form for the Years 2008 to 2014 inclusive.

Response:

The requested reports are provided in the Attachment 11.1.

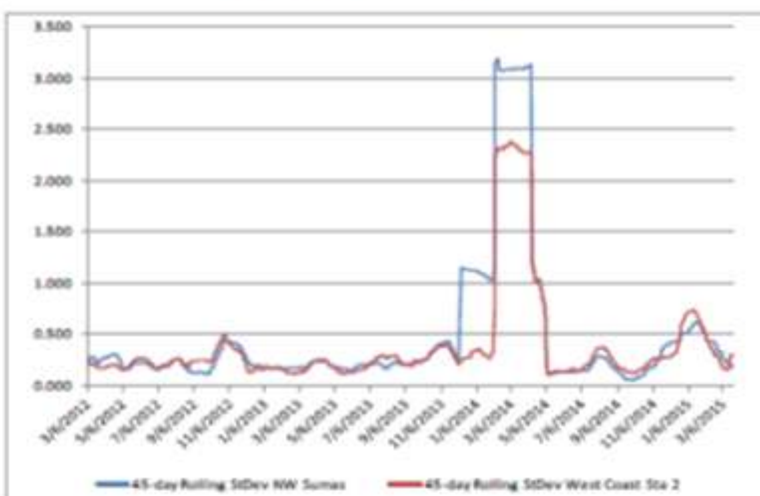
12. Reference: Exhibit B-1, Appendix B, Page 68

Figure 8: NW Sumas and West Coast Station 2 Daily Spot Prices



Source: SNL Day-Ahead Natural Gas Prices - Daily

Figure 9: 45-day Rolling Average Volatility (Measured by Standard Deviation) NW Sumas and West Coast Station 2



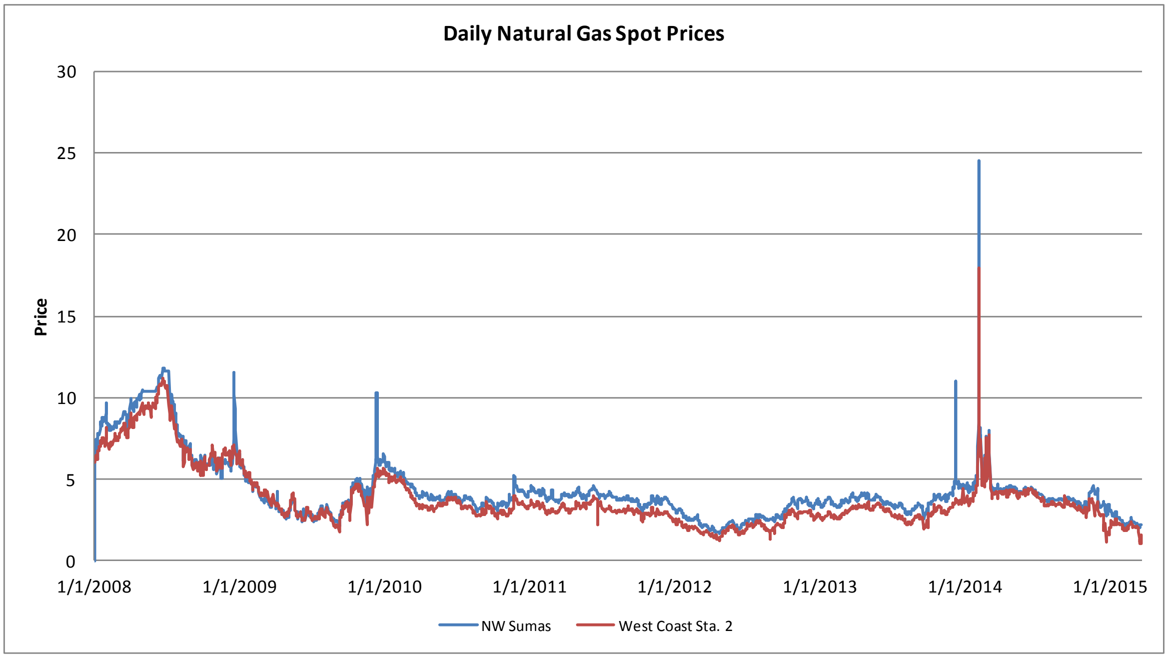
Source: SNL Day-Ahead Natural Gas Prices - Daily

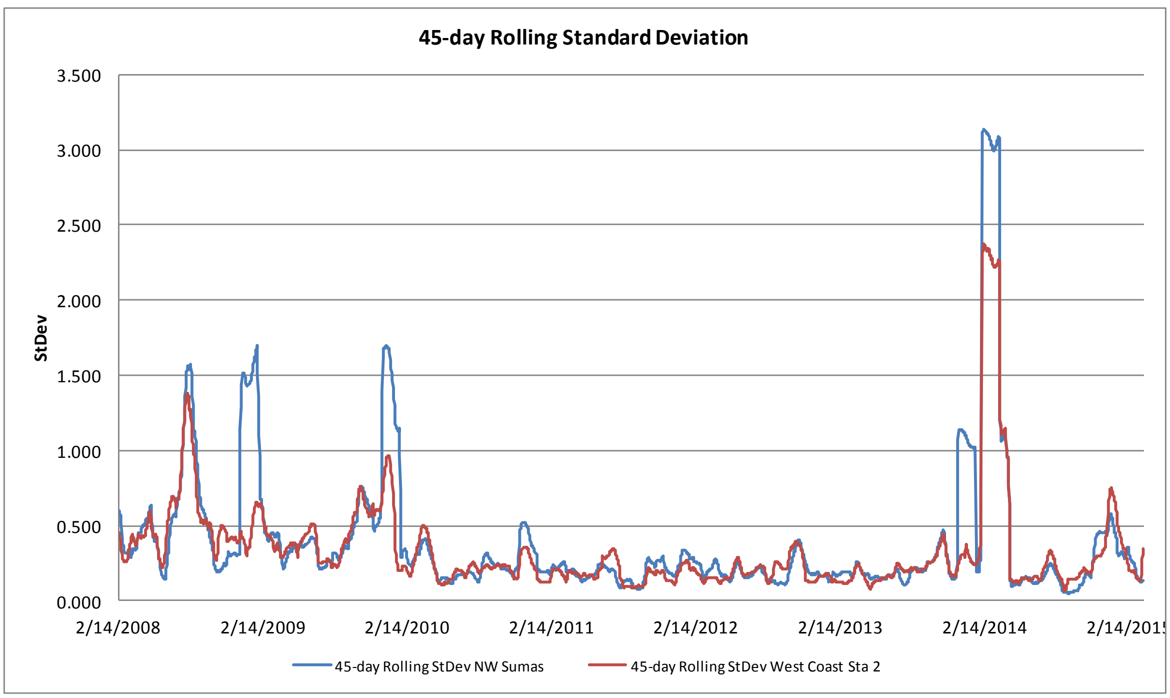
> As the figures reflect, gas prices have remained essentially the same since 2012, but volatility has increased at both pricing locations despite the increased shale production and may spike during supply shortages as seen in the winter of 2013-2014, creating price and market risk for FEI and its customers.

12.1 Please provide the above figures dating back to 2008.

<u>Response:</u>

The requested figures follow.





Source: SNLspot price data except for West Coast Sta. 2 spot prices from January 1, 2008 through May 28, 2009, sourced from Gas Daily. All spot prices are in Canadian dollars/GJ.

12.2 What was the cause of the supply shortages resulting in price and volatility spikes shown in the winter of 2013- 2014?

Response:

According to the U.S. Energy Information Administration, price peaks in the Northwest were caused by the following.

- Increasingly expensive supply from Alberta, combined with bitterly cold temperatures, low storage, and drops in Rockies production on cold days, led to price spikes in the West.
- The spot price from February through March surpassed $8/MMBtu at times at Niska's AECO Hub, located near the AECO storage facility in southeastern Alberta, a key trading point for western Canadian gas. This price was well above the $2/MMBtu prices at which gas traded at AECO as recently as September 2013.
- Working gas inventories in California fell from 346 Bcf at the end of October to 94 Bcf by the end of March 2014, their lowest level for that month since 2003. Inventories in Washington also reached their lowest level since 2008, while inventories in Oregon fell to their lowest level since 2005.
- As a result, prices spiked at PGE Citygate (California) and Northwest Sumas (Washington) when the West Coast was hit with a cold snap in early February. Prices also rose at Northwest Sumas when the Pacific Northwest was hit with cold weather in early December.[6]

12.3 Please provide the estimated average increase in residential customer bills that occurred in the winter of 2013 to 2014.

Response:

Please refer to the following table which shows the rate changes for FEI Rate Schedule 1 residential customer bills with an average annual consumption of 90 gigagoules from October 2013 to November 2014.

6 http://www.eia.gov/naturalgas/review/winterlookback/2013/#tabs_Consumption-4.

FEI Mainland RS 1 History

Average Annual Use Rate (Gigajoules) **90**

	Oct 1, 2013	Jan 1, 2014	% Change	Dollar Change	Apr 1, 2014	% Change	Dollar Change	Oct 1, 2014	% Change	Dollar Change	Nov 1, 2014	% Change	Dollar Change
Fixed Daily Basic Charge	$0.3890	$0.3890	**0.00%**	**$0.00**	$0.3890	**0.00%**	**$0.00**	$0.3890	**0.00%**	**$0.00**	$0.3890	**0.00%**	**$0.00**
Delivery Charge per Gigajoule	$3.397	$3.621	**6.59%**	**$0.224**	$3.621	**0.00%**	**$0.000**	$3.621	**0.00%**	**$0.000**	$3.641	**0.55%**	**$0.020**
Storage and Transport per Gigajoule	$1.192	$1.303	**9.31%**	**$0.111**	$1.303	**0.00%**	**$0.000**	$1.303	**0.00%**	**$0.000**	$1.303	**0.00%**	**$0.000**
Cost of Gas per Gigajoule	$3.272	$3.272	**0.00%**	**$0.000**	$4.640	**41.81%**	**$1.368**	$3.781	**-18.51%**	**-$0.859**	$3.781	**0.00%**	**$0.000**
Average Annual Bill	**$850**	**$880**	**3.55%**	**$30**	**$1,003**	**14.00%**	**$123**	**$926**	**-7.71%**	**-$77**	**$927**	**0.19%**	**$2**

All components of rates include applicable rate riders.

12.4 Please provide the estimated average increase in commercial customer bills that occurred in the winter of 2013 to 2014.

Response:

Please refer to the following table which shows the rate changes for FEI Rate Schedule 3 large commercial customer bills with an average annual consumption of 3,549 gigagoules from October 2013 to November 2014.

1

FEI Mainland RS 3 History

Average Annual Use Rate (Gigajoules) **3,549**

	Oct 1, 2013	Jan 1, 2014	% Change	Dollar Change	Apr 1, 2014	% Change	Dollar Change	Oct 1, 2014	% Change	Dollar Change	Nov 1, 2014	% Change	Dollar Change
Fixed Daily Basic Charge	$4.3538	$4.3538	0.00%	$0.00	$4.3538	0.00%	$0.00	$4.3538	0.00%	$0.00	$4.3538	0.00%	$0.00
Delivery Charge per Gigajoule	$2.344	$2.467	5.25%	$0.123	$2.467	0.00%	$0.000	$2.467	0.00%	$0.000	$2.479	0.49%	$0.012
Storage and Transport per Gigajoule	$0.935	$1.114	19.14%	$0.179	$1.114	0.00%	$0.000	$1.114	0.00%	$0.000	$1.114	0.00%	$0.000
Cost of Gas per Gigajoule	$3.272	$3.272	0.00%	$0.000	$4.640	41.81%	$1.368	$3.781	-18.51%	-$0.859	$3.781	0.00%	$0.000
Average Annual Bill	$24,840	$25,912	4.31%	$1,072	$30,767	18.74%	$4,855	$27,718	-9.91%	-$3,049	$27,761	0.15%	$43

2 **All components of rates include applicable rate riders.**

12.5 Please provide the estimated average increase in industrial customer bills that occurred in the winter of 2013 to 2014.

Response:

Due to the number of different industrial rate schedules and the large variation in the consumption both between and within the rate schedules, FEI has provided in the following table only an example, using rate changes for FEI Rate Schedule 5 customer bills with an average annual consumption of 9,422 gigagoules.

1

FEI Mainland RS 5 History

Average Annual Use Rate (Gigajoules)	**9,422**
Average Daily Demand	**50.7**

	Oct 1, 2013	Jan 1, 2014	% Change	Dollar Change	Apr 1, 2014	% Change	Dollar Change	Oct 1, 2014	% Change	Dollar Change	Nov 1, 2014	% Change	Dollar Change
Fixed Daily Basic Charge	$587.00	$587.00	**0.00%**	**$0.00**	$587.00	**0.00%**	**$0.00**	$587.00	**0.00%**	**$0.00**	$587.00	**0.00%**	**$0.00**
Demand Charge per Gigajoule per Month	$17.531	$17.850	**1.82%**	**$0.319**	$17.850	**0.00%**	**$0.000**	$17.850	**0.00%**	**$0.000**	$17.925	**0.42%**	**$0.075**
Delivery Charge per Gigajoule	$0.675	$0.736	**9.04%**	**$0.061**	$0.736	**0.00%**	**$0.000**	$0.736	**0.00%**	**$0.000**	$0.738	**0.27%**	**$0.002**
Storage and Transport per Gigajoule	$0.716	$0.812	**13.41%**	**$0.096**	$0.812	**0.00%**	**$0.000**	$0.812	**0.00%**	**$0.000**	$0.812	**0.00%**	**$0.000**
Cost of Gas per Gigajoule	$3.272	$3.272	**0.00%**	**$0.000**	$4.640	**41.81%**	**$1.368**	$3.781	**-18.51%**	**-$0.859**	$3.781	**0.00%**	**$0.000**
Average Annual Bill	**$61,645**	**$63,318**	**2.71%**	**$1,673**	**$76,207**	**20.36%**	**$12,889**	**$68,114**	**-10.62%**	**-$8,093**	**$68,178**	**0.09%**	**$64**

2 **All components of rates include applicable rate riders.**

3

12.6 Please provide a definition of 'market risk'.

Response:

Mr. Coyne refers to market risk in the context of price risk and the extent to which prices may be influenced by market factors such as weather, supply, demand, competition, technology, and other factors that arise in natural gas markets.

12.7 Please provide quantification of the expected increase in market risk.

Response:

Mr. Coyne has not provided a quantitative assessment of market risk, nor could he. Mr. Coyne refers to market risk in the context of volatility in Pacific Northwest natural gas supply prices. Mr. Coyne has qualitatively assessed these risks for FEI on p. 78 of his direct testimony and found that the impact on FEI's business risk profile attributable to "gas price levels and volatility" was "fair". This relatively neutral assessment considered the volatility and price spikes observed on the West Coast system, but also that volatility is tempered by FEI's ability to access storage and LNG peaking capacity on its system in periods of extreme shortages. Qualitative risk factors do not easily lend themselves to quantitative assessments, but rather are considered as inputs to the overall risk assessment, in which individual risk factors, such as gas supply volatility, must be afforded weight depending on the implications and magnitude of the risk for the company in accordance with the judgment of the person developing the assessment.

12.8 Please confirm that customers absorb the full cost of natural gas under both PBR and cost of service.

Response:

Confirmed, as stated on p. 78, lines 8 through 9. Full recovery of commodity costs is common in Canada and the U.S. and is true for all proxy companies.

12.8.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 1.12.8.

12.9 Please provide an estimate of the number of customers that transitioned from natural gas to another energy source as a result of the price spike in the winter of 2013-2014.

Response:

FEI does not have the ability to provide an estimate of the number of customers that may have switched to another energy source specifically because of the short term price spike in the winter of 2013-14. For industrial customers with fuel-switching capabilities it may have led to a decrease in demand, but in general each customer is so unique that a spike of a certain magnitude at a certain time of year will not always have the same impact as it also depends on the cost of the alternative fuel that the facility has the ability to switch over to in the short term. Customer hedging, production levels and the availability and cost of alternate fuel choices are all factors that each customer considers individually. As a result, it is not possible to accurately estimate the number of customers that switched fuels as a result of the short term price spike in 2013-2014.

12.10 Please provide the total throughput for the years 2008 to 2015.

Response:

FEI has provided below the total actual throughput, including bypass and NGT customers, for 2008 through 2014. In addition, FEI has provided the actual year-to-date throughput as of November 30, 2015.

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual YTD - November
Residential	83,452.1	77,524.7	69,737.4	78,868.6	73,146.7	74,487.6	71,743.8	51,667.0
Commercial	56,176.5	55,032.2	50,609.5	57,361.4	55,177.2	54,739.8	53,030.1	37,495.0
Industrial	80,850.2	73,889.6	72,243.0	66,673.8	70,089.9	70,159.8	69,986.3	54,275.0
Total	220,478.8	206,446.4	192,589.9	202,903.8	198,413.8	199,387.2	194,760.2	143,437.1

12.11 Is FEI is able to make use of deferral accounts to diminish the impact of volatility in the cost of natural gas?

Response:

No, deferral accounts do not diminish the impact of volatility in the cost of natural gas. The cost of natural gas includes the actual daily and monthly market prices that FEI pays to its suppliers. The deferral accounts do, however, help diminish some of the impact of the volatility in FEI's commodity rates that it charges to its customers. The deferral accounts and their balances, as well as the forward price outlook for the cost of gas, are the two main components that determine FEI's commodity rates. The gas cost deferral mechanisms that are in place today are unchanged in any material aspect from what has been in place since 2004.

12.11.1 If no, please explain why not.

Response:

Please refer to the response to CEC IR 1.12.1.

13. Reference: Exhibit B-1, Appendix B, Page 77

> 3) Gas Price Levels and Volatility – Fair – FEI is served primarily by the Westcoast Spectra System and the company holds approximately 35.5 PJs of storage capacity consisting of two peak shaving LNG facilities and off-system capacity contracted with third parties. Gas prices have become more volatile on the West Coast system and have tended to spike during supply shortages which ultimately factors negatively into customers' perceptions of natural gas use. Though FEI enjoys flow through recovery of gas commodity costs and generally experiences a low rate of customer bad debts, it is my experience that volatile natural gas prices and price spikes do factor into customers' perceptions of gas use and could influence fuel-switching decisions to alternative energy sources from natural gas.

13.1 What is the rate of FEI bad debts?

<u>Response:</u>

According to FEI, its specific level of bad debt charge averaged over three years is 0.26 percent of mass market revenues or those revenues directly related to FEI's residential and commercial distribution operations.

13.2 Please provide the bad debts rates for the comparative Canadian and US utilities.

<u>Response:</u>

Mr. Coyne's statement that FEI "generally experiences a low level of bad debts," referenced above, was based on discussions with the company and is not the result of his comparative research. Mr. Coyne has not identified the level of bad debts for each company. Nor has he observed through his research that this is a differentiating factor that has materially impacted the risk profile of the proxy companies. All utilities experience a certain level of bad debts and most utilities experience a "low" level of bad debts. Through Mr. Coyne's risk research on FEI and the proxy group companies, there was no evidence that bad debts posed a substantial risk for any of the companies and as such, does not consider it a differentiating risk factor that warrants separate consideration.

13.3 Please confirm that low, or declining gas prices could influence fuel switching to natural gas.

Response:

The relative price of natural gas compared to the price of alternative fuels is one of the factors that can influence fuel switching to or from natural gas Over the short-term, customers with fuel-switching capabilities, mainly some of FEI's industrial customers, will switch to the lowest cost fuel option (sometimes on a day-to-day basis). However, for the majority of FEI's demand (particularly for the demand in space-heating and water-heating applications), fuel switching is more of a medium to long-term consideration, and may be impacted by other factors more than fuel price such as public policy or new technology.

13.3.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 1.13.3.

14. Reference: Exhibit B-1, Appendix B, Pages 69 and 77

4. Volume/Demand Risk

FEI's residential and commercial sector demand is dominated by space heating and water heating, which comprise approximately 83 percent and 71 percent for each sector, respectively.[111] Together, residential and commercial space and water heating segments make up 55 percent[112] of FEI's total energy use volumes by end-use, with industrial use and transportation volumes making up the remainder. Though new customer growth is trending upward, throughput remains relatively flat,[113] indicating that use per customer continues to decline. Further, new housing starts with natural gas for space heating have continued to trend downwards with natural gas losing market share to electricity for both space heating and water heating. Today, new homes in British Columbia with gas service are less likely to use natural gas for water heating than electricity. As Figure 10 reveals, the general trend is that electricity is displacing natural gas in residential energy use. Figure 10 shows the percentages of electricity and natural gas use as a percent of total residential energy use.

4) Volume/Demand Risk – Challenging - Declining use per customer and attracting new customers will continue to present significant challenges for FEI. FEI's loss of market share to electricity and the downturn in new housing starts in general has threatened to lessen FEI's throughput, despite the prospect of attracting industrial demand with low natural gas prices (though as we saw in Figure 11, decreases in natural gas prices do not guarantee increases in industrial demand). These losses of market share to electricity are slightly mitigated by the potential to increase services in the transportation sector and through LNG expansion.

14.1 Does the author base his assessment on the near term expectations of throughput, or long term expectations of throughput? Please explain.

Response:

Mr. Coyne's assessment is based on the long-term expectations for throughput. All else being equal, over a period of time, FEI's gradual loss of market share to electricity and the impact of its declining use per customer on its throughput, will pose challenges to FEI. FEI will need to continue to expand utility services in other areas, i.e., LNG sales, natural gas vehicles, adding new industrial customers to mitigate the impact of declining use and loss of market share on its throughput.

14.2 Please provide the near term forecast for FEI's throughput.

Response:

Please refer to the response to CEC IR 1.27.3.

14.3 Please provide the long term forecast for FEI's throughput.

Response:

The current reference case long term forecast for Residential, Commercial and Industrial demand is contained in the 2014 LTRP, and is provided below.

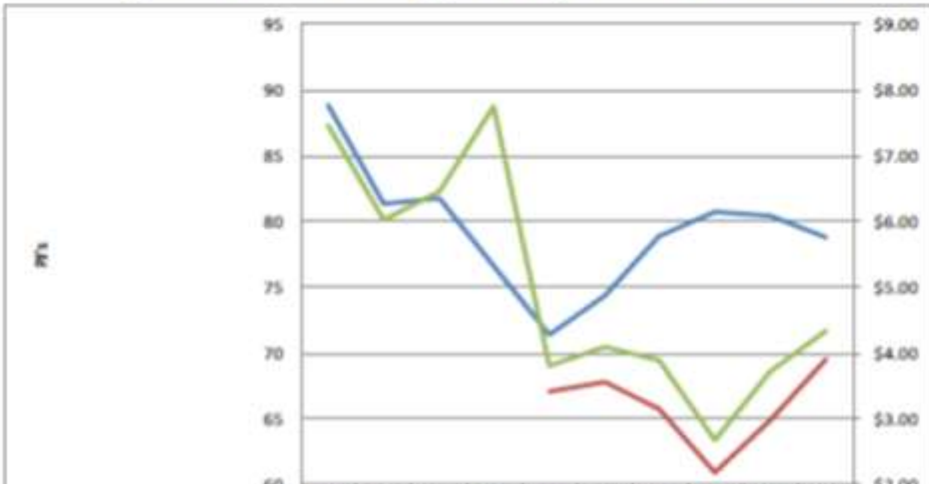
	2011	2016	2021	2026	2031	2033
Total Throughput (PJ)	195	201	199	200	201	201
source: 2014 LTRP						

The forecast including growth in natural gas for transportation (also included in the 2014 LTRP) is provided below.

	2011	2016	2021	2026	2031	2033
Total Throughput (PJ)	195	202	204	210	224	233

15. Reference: Exhibit B-1, Appendix B, Page 72

Figure 11: Industrial Throughput and Spot Gas Prices 2005-2014



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Industrial Throughput (PJ's)	88.9	81.4	81.8	76.6	71.4	74.4	78.9	80.8	80.4	78.8
West Coast Sta 2					$3.42	$3.57	$3.16	$2.19	$2.98	$3.91
NW Sumas	$7.46	$6.03	$6.46	$7.75	$3.80	$4.10	$3.89	$2.69	$3.72	$4.33

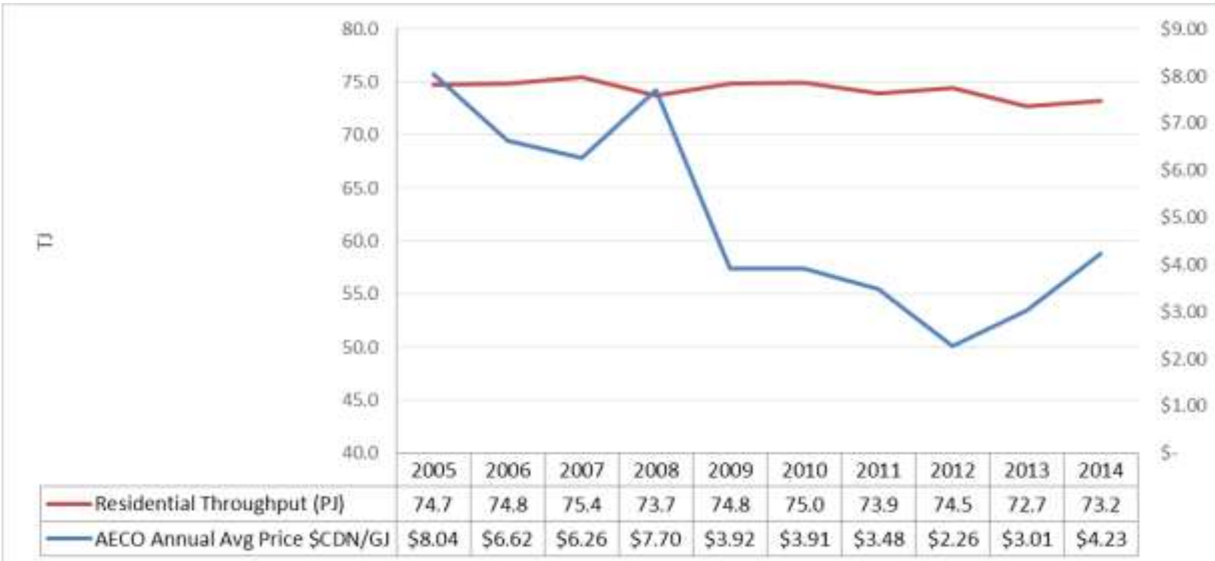
Source: SNL Spot Natural Gas Price Indices, industrial throughput data provided by FEI

In aggregate, FEI's use per customer is declining by greater than 1 percent per year,[118] its capture rate for new home construction and housing starts in BC are low and are projected to trend down over time; and as the figure shows, industrial throughput does not always fill in the gaps. In my opinion this presents a significant long term risk for the Company.

15.1 Please provide the equivalent of Figure 11 for residential customers.

Response:

The following figure provides the normalized residential throughput from 2005 to 2014 along with the AECO annual average price in $CDN per GJ.



15.2 Please provide the equivalent of Figure 11 for commercial customers.

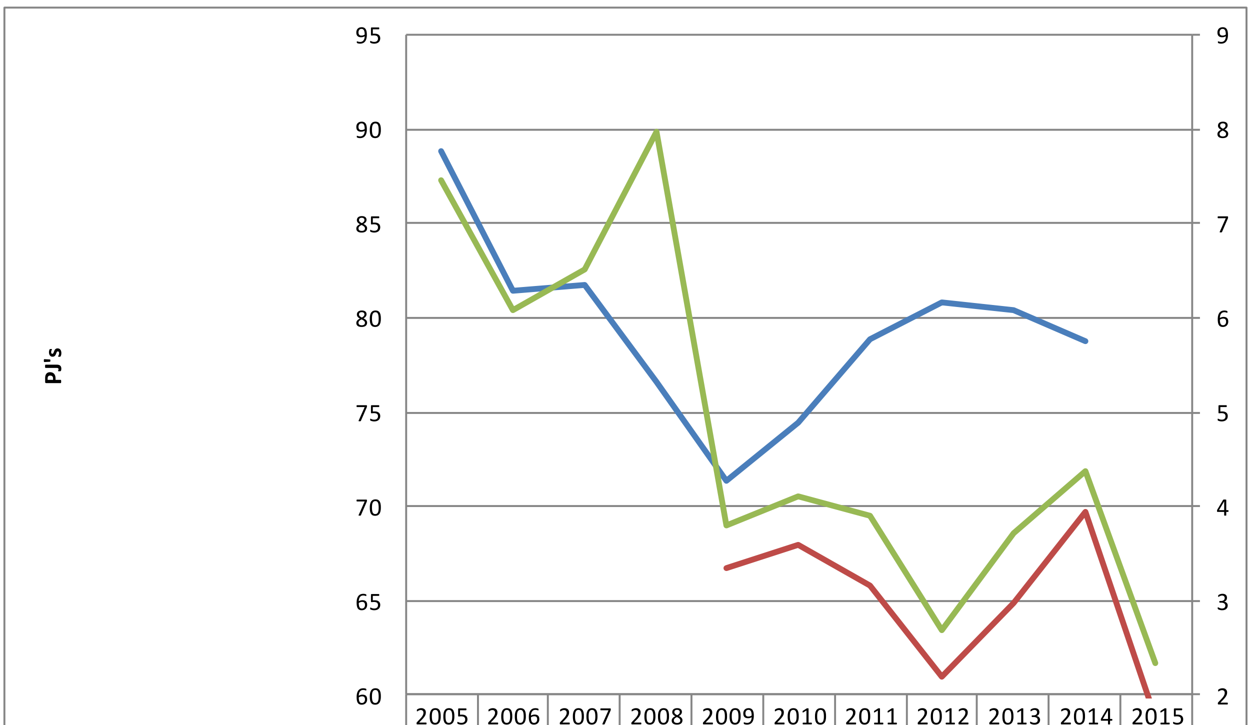
Response:

The normalized commercial throughput is shown below along with the AECO average annual price in $CDN per GJ.

15.3 Please extent the spot prices through to 2015, up to and including November 2015.

Response:

The following figure extends the West Coast Station 2 and NW Sumas spot prices to November 2015.



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Industrial Throughput (PJ's)	88.9	81.4	81.8	76.6	71.4	74.4	78.9	80.8	80.4	78.8	
West Coast Sta 2 $CAD					3.345	3.593	3.154	2.184	2.982	3.938	1.750
NW Sumas $CAD	7.460	6.088	6.505	7.975	3.799	4.116	3.891	2.687	3.718	4.366	2.332

16. Reference: Exhibit B-1, Appendix B, Page 73

> In summary, declining use and attracting new customers will continue to present significant challenges for FEI. Though those challenges were present in 2012, FEI's loss of market share to electricity and the downturn in new housing starts, in general, threatens FEI's long-term throughput. These losses of market share to electricity are slightly mitigated by the potential to increase core services in transportation fuels and LNG expansion, but those activities are in the nascent stages and would not materially benefit FEI's throughput in the near term.[119] As FEI has stated in its Risk Evidence, "While energy price remains a driver of business risk, recent experience suggests that other non-price considerations such as GHG emissions, type of housing mix and the size of new dwellings, customer perceptions and government policy, particularly local governments' support for non-fossil fuel alternatives through updates to building codes and bylaws, (discussed in subsequent sections) are taking on greater importance in the decisions of energy consumers."[120] Overall, though these issues were all present in the last proceeding,

16.1 Please provide an overview of what may be considered 'long-term' and what may be considered near-term in assessing the risk of throughput.

Response:

The risks Mr. Coyne has identified with respect to throughput are entirely long-term. That is to say that they will not be mitigated in the next year or two. They are entrenched and will continue to weigh on FEI in the coming years.

16.2 Please confirm that the loss of market share to electricity and downturn in housing starts is not a threat in the near term.

Response:

The term "threat" is ambiguous.

FEI would not suggest that these factors are posing an imminent threat to the viability of the business. The risk of non-recovery of capital is a longer term one.

These factors are a present concern for FEI in the sense that they are part of a longer term unfavourable trend. FEI's 2012 Residential End-Use Survey (REUS) as well as BC Hydro's

2014 Residential End-Use Survey both confirm that natural gas continues to lose market share in space heating and water heating sectors to electricity. Please refer to the following excerpts from BC Hydro's 2014 REUS:

> *"There has been a gradual decrease over the past thirteen years in the use of natural gas and an accompanying increase in the use of electricity as the main hot water heating fuel in the Lower Mainland and in the Southern Interior"*[7].

> *"The use of natural gas as a main space heating fuel has continued its slow downward trend in the Lower Mainland and in the North having decreased 1 to 2 points to their all-time lowest levels of 58 percent and 61 percent, respectively. Primary reliance on natural gas has gone by and large unchanged over the past several years in the Southern Interior and on Vancouver Island, currently measuring 58 percent and 19 percent"*[8].

Furthermore, as shown on page 64 of Mr.Coyne's evidence, the long-term housing starts forecast in BC demonstrates a downturn. In the short-term, the main concern relates to the downward trend in single-family dwellings starts compared to an increase in number of multi-family dwellings (MFD), since FEI continues to face a lower capture rate in the MFD market.

16.3 Can the opportunity to increase core services in transportation and LNG expansion material benefit FEI's throughput in the long term?

Response:

FEI's efforts to increase natural gas throughput to serve transportation markets and LNG expansion have the potential to provide net benefits to FEI's throughput in the long term and deliver rate benefits for other customers, but the magnitude and timing of benefits is uncertain at this time. Although FEI does expect net benefits from these growth areas, the increased throughput will be in the industrial rate classes, which have lower delivery rates than the residential and commercial rate classes in which the throughput decreases are occurring, and there are some incremental costs associated with securing the new load. In other words, it will take a larger number of GJs of throughput from the new initiatives to offset each GJ of lost load in the residential or commercial classes. For example, CNG customers typically receive service under Rate Schedule 25 so the RS 25 delivery charges represent the typical volumetric benefit that will be achieved from new throughput. Since residential delivery rates are about 2.5 to 3

[7] BC Hydro 2014 REUS, page 106.
[8] BC Hydro 2014 REUS, page 60.

times the delivery rates of RS 25, it would take 2.5 to 3 GJ of added CNG volumes to offset one GJ of lost residential load. For LNG customers, after considering the effect of incremental costs, the net delivery benefit from one GJ of LNG throughput will be 1/10 or less of the residential delivery charge so 10 GJs or more of LNG throughput will be needed to offset one GJ of lost residential throughput.

16.3.1 If yes, please provide an assessment of the size of the opportunity FEI may experience in the long term from these activities.

Response:

There are many possible outcomes that may result from FEI's pursuit of the transportation and LNG expansion initiatives and consequently there is a large range in the magnitude of net benefits that would be available to FEI and existing customers from these activities.

Growth in the local transportation markets is likely to proceed gradually as FEI is successful in attracting new customers to its Rate Schedule (RS) 46 LNG service (although more rapid growth is possible in some market segments such as, for example, the mine haul and marine sectors). In the short to medium term, throughput from local transportation markets is not expected to be significant relative to FEI's existing system throughput.

On the other hand, providing natural gas delivery to new or expanded LNG facilities under FEI's RS 50 will grow in large discrete steps dependent on corporate investment decisions that are still to be made to expand LNG capacity or build new facilities. The decisions to proceed with such projects will be affected by many factors, such as the financial market conditions, world energy / LNG market conditions, the project proponents' success in finding off-takers ("customers"), the success in securing all necessary licenses and permits, and various others.

Please refer also to the response to BCUC IR 1.21.3 regarding the potential throughput and benefits over the long term from the possible initial LNG facilities that would take delivery service from FEI under Rate Schedule 50. In rough terms the total LNG development potential in FEI's service territory is in the order of 2 to 3 times the quantities identified in BCUC IR 1.21.3; however other LNG expansions and projects that would make up a higher growth scenario are in the very early stages of evaluation and development and should be considered as having a low likelihood of proceeding in the next three to five years.

17. Reference: Exhibit B-1, Appendix B, Pages 74 and 76

> FEI had been previously regulated under cost of service ratemaking from 2010-2013, but moved back to performance based ratemaking through at least 2019. PBR ratemaking poses additional risks on the regulated utility as it requires the utility to consistently achieve greater efficiencies in order to earn its allowed return. In fact, a principal objective of PBR is to de-link the relationship between costs and rates. Though FEI's PBR plan does have some moderating features, such as capital programs outside the formula mechanism and regulatory deferral accounts that are allowed flow-through treatment in the PBR mechanism, the utility remains subject to the risk that formulaic PBR rates may diverge from just and reasonable rates if, for example, productivity gains are not realized. Credit research and ratings analysts support this view. For example, in DBRS's May 2012 Industry Study, Assessing Regulatory Risk in the Utilities Sector, DBRS found incentive regulation to create more risk for the utility than cost of service ratemaking. In that Study, DBRS stated,
>
> > "Cost-of-Service (COS) Versus Incentive Regulation Mechanism (IRM): In general, under COS, regulated utilities are allowed to recover prudently incurred operating costs and earn a reasonable return on their investment. Under IRM, revenue requirements for the year are based on a COS base year, adjusted for inflation (CPI) and minus a productivity factor (X), which is set by the regulator. This forces utilities to maintain their operational efficiency to achieve allowed ROE. DBRS views COS as lower-risk than IRM. In addition, DBRS also considers the length of an IRM period between the COS years. DBRS's scoring system gives a higher score for a shorter IRM period."
>
> has mitigating features that will allow for cost recovery and the sharing of downside earnings risk with customers. I consider the new PBR plan to have very little near term impact on FEI's business risk profile. However, in the later years of the Plan, as the revenue requirement is limited by I-X, the Company will be harder pressed to find productivity gains under the Plan and earnings will be exposed to greater risk.

17.1 For how many years, out of the last 20 years, has FEI been operating under PBR?

<u>Response:</u>

FEI has operated under PBR for 11 of the last 20 years (1998 to 2001, 2004 to 2009, and 2014).

17.2 Please provide the financial returns generated during each of the last 20 years, and identify which years were under PBR and which years were under Cost of Service.

Response:

The allowed and actual returns for 1995 through 2014, as well as the indication of whether FEI was under PBR or cost of service in each respective year, are provided in the table below.

	ROE			
	Allowed[1] (a)	Actual Pre-ESM (b)	Actual Post-ESM[2] (c)	PBR or cost of service (d)
1995	12.00%	12.03%	N/A	Cost of Service
1996	11.00%	11.80%	N/A	Cost of Service
1997	10.25%	11.27%	N/A	Cost of Service
1998	10.00%	9.41%	9.70%	PBR
1999	9.25%	10.70%	9.97%	PBR
2000	9.50%	10.75%	10.12%	PBR
2001	9.25%	9.38%	9.31%	PBR
2002	N/A	9.73%	N/A	N/A
2003	9.42%	10.23%	N/A	Cost of Service
2004	9.15%	9.34%	9.25%	PBR
2005	9.03%	10.78%	9.91%	PBR
2006	8.80%	10.47%	9.64%	PBR
2007	8.37%	10.73%	9.55%	PBR
2008	8.62%	10.64%	9.63%	PBR
2009	8.99%	11.89%	10.44%	PBR
2010	9.50%	9.42%	N/A	Cost of Service
2011	9.50%	10.15%	N/A	Cost of Service
2012	9.50%	10.12%	N/A	Cost of Service
2013	8.75%	9.12%	N/A	Cost of Service
2014	8.75%	9.54%	9.20%	PBR

Notes:

[1] N/A indicates that an approved revenue requirement did not exist for that year

[2] Post-ESM only applicable for the years when FEI was under PBR (1998-2001, 2004-2009, 2014)

17.3 Please provide the allowed return for each year.

Response:

Please refer to the response to CEC IR 1.17.2.

17.4 Please confirm that the Commission is tasked with setting Just and Reasonable Rates under Utilities Commission Act Sections 59 – 61.

Response:

Confirmed.

17.4.1 If not confirmed, please explain why not.

Response:

Not applicable. Please refer to the response to CEC IR 1.17.4.

17.4.2 Please provide an explanation as to what would constitute rates that were not 'Just and Reasonable', with quantification of rates that are too low, and rates that would be 'too high'.

Response:

The UCA defines what is meant by the term "just and reasonable". Section 59(5) states:

(5) In this section, a rate is "unjust" or "unreasonable" if the rate is

> (a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,
>
> (b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or
>
> (c) unjust and unreasonable for any other reason.

Past court and regulatory decisions have identified considerations for assessing whether a return is fair, including capital attraction, comparable investment and financial integrity. For instance, the NEB had held in Decision RH-1-2008:

> The Fair Return Standard requires that a fair or reasonable overall return on capital should:
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
> - enable the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and
> - permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement).

The Commission has previously adopted this articulation.

It is not possible to quantify rates that are too high or too low in the abstract. These determinations will be fact specific. FEI's evidence demonstrates that the fair return for the Company having regard to the risks facing the utility, combined with capital market conditions, and other factors, is higher than the current allowed return (ROE and equity component). Rates must reflect a Fair Return (i.e., the obligation to set rates that meet the Fair Return Standard is absolute), and cannot be judged to be too high based on the rate impacts associated with meeting that standard.

17.4.3 Please discuss the recourse that FEI and ratepayers would have if rates were not 'Just and Reasonable'.

Response:

The utility can apply to change rates that it regards as not just and reasonable. Utility ratepayers and the utility can file a complaint with the Commission under section 58. Section 58 also contemplates the Commission acting proactively, as it had done in the context of the Generic Cost of Capital proceedings in 2012. Section 58(1) states:

> 58 (1) The commission may,
>
> (a) on its own motion, or
>
> (b) on complaint by a public utility or other interested person that the existing rates in effect and collected or any rates charged or attempted to be charged for service by a public utility are unjust, unreasonable, insufficient, unduly discriminatory or in contravention of this Act, the regulations or any other law,
>
> after a hearing, determine the just, reasonable and sufficient rates to be observed and in force.

17.5 Please confirm that the FEI PBR contains both financial and non-financial 'off ramps.'

Response:

The following includes FEI's response to CEC IR 1.17.5 to CER IR 1.17.8.

FEI confirms that its PBR plan contains both financial and non-financial off-ramp mechanisms as well as a Z-factor mechanism for recovery of prudently incurred costs related to unforeseen and non-controllable events caused by exogenous factors.

The financial off-ramp would be triggered if earnings in any one year varies from the approved ROE by more than +/- 200 bps (post-sharing) or if the earnings average more than +/- 150 bps (post-sharing) from the approved ROE for two consecutive years.

The non-financial off-ramp on the other hand is not based on any pre-defined quantitative amount and would be triggered if service quality fell to an unacceptable level judged by the Commission as sustained serious degradation of service. Similar to the financial off-ramp mechanism, the triggering of the non-financial off-ramp could warrant a complete review of the PBR plan.

For information regarding the Z-factor mechanism and the associated regulatory risk due to the inclusion of a materiality threshold please refer to the response to the BCUC IR 1.17.1.

17.6 Please confirm that the FEI PBR contains the opportunity for including 'Exogenous Factors' as a flow through item.

Response:

Please refer to the response to CEC IR 1.17.5.

17.7 Please provide an overview of the financial off-ramp under PBR.

Response:

Please refer to the response to CEC IR 1.17.5.

17.8 Please provide an overview of the non-financial off-ramp under PBR.

Response:

Please refer to the response to CEC IR 1.17.5.

17.8.1 Please provide a discussion of how rates that were not 'Just and Reasonable' could arise in the context of PBR and the available off-ramps.

Response:

As discussed in response to CEC IR 1.17.4.2, the UCA defines what is meant by the term "just and reasonable". Section 59(5) states:

> (5) In this section, a rate is "unjust" or "unreasonable" if the rate is
>
> (a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,
>
> (b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or
>
> (c) unjust and unreasonable for any other reason.

One way that rates would not be just and reasonable under PBR is if the Commission were to set an allowed ROE / common equity ratio that was insufficient to meet the three elements of the NEB test for determining a Fair Return.

Moreover, even if the allowed return is set at an appropriate level, the PBR design (including I-X, growth factors, etc.) would also have to permit the utility to have a reasonable opportunity to achieve that allowed return. Triggering the off-ramp (which is set as a band around the allowed ROE) would be a potential indication that the Plan was mis-calibrated and might require changes or a return to Cost of Service regulation in order to meet the Fair Return Standard. However, a PBR plan that does not allow the utility a reasonable opportunity to earn the allowed return is still unjust and unreasonable even if the off-ramps are not triggered.

In the specific context of FEI's PBR plan and in reference to CEC questions 1.17.5 to 1.17.8, FEI provides the following remarks:

- The non-financial off-ramp is created to protect the interests of the ratepayers in case of serious degradation of service quality and is not designed to protect FEI's shareholder interests.
- The financial off-ramp is only triggered if in any given year the variance between approved and realized ROE is more than 200 bps post sharing (or 400 bps pre-sharing) or if the average variance between the approved and realized ROE is more than 150 bps post sharing (or 300 bps pre-sharing) for two consecutive years. In other words, the off-ramp mechanism is only applied when there are significant problems in the PBR plan and would not prevent a situation where the other parameters of the plan cause FEI to

fall well short of the allowed ROE (i.e., a shortfall of 149 bps post-sharing is not insignificant). The deadbands still allow for earnings variability.

- In addition, as explained above, triggering the off-ramp brings additional uncertainty as it might require changes to the PBR Plan or a return to cost of service regulation which would bring additional regulatory lag.
- As explained on page 74 of Appendix C, the determination of the materiality threshold for exogenous events gives rise to the potential denial of prudently incurred costs and increases the underlying risk to the Company. Please refer to the response to BCUC IR 1.17.1 for more information.

Further, the risk inherent in PBR is not limited to the discussions of "fair and reasonable" rates but also relates to the potential increased cash flow volatility compared to Cost of Service Regulation as explained in Moody's July 2015 credit rating. However this risk is assessed to be marginal.

17.9 Please provide the FEI application for the 2014-2018 Performance Based Ratemaking.

Response:

FEI respectfully declines to file the PBR Application in its totality. The PBR Application is large, and there is limited value from adding all of that material to the record. The parameters of the PBR plan that inform FEI's risk profile and cost of capital are established by the Commission's PBR Decision, not FEI's initial Application.

The PBR Application is available online at www.bcuc.com. To the extent that CEC considers there is something of particular relevance in the PBR Application, it can seek to file the relevant portions as part of its own evidence in this proceeding.

17.10 Please confirm that the opportunity for the utility to achieve higher earnings under PBR is inherent in a PBR.

Response:

The statement is too general, as it is premised on a well designed and functioning PBR plan. Based on FEI's experience with PBR with a symmetrical earnings sharing mechanism, FEI agrees that a well-designed PBR Plan can afford an opportunity for the utility to achieve higher earnings and for customers to have correspondingly lower rates (other things being equal). As alluded to by DBRS in the quotation above, the traditional trade-off for this is that the utility is accepting greater risk via a longer test period and formula driven revenues that incorporate an efficiency factor.

Moody's July 2015 FEI credit report also explained that the shift to PBR marginally increases risk due to the potential for increased cash flow volatility compared to cost of service regulation.

As shown in the response to CEC IR 1.17.2, FEI's ROE under PBR has only been marginally higher than allowed when compared to Cost of Service. For the 11 years that FEI was under PBR, its ROE was only 9 basis points higher than the average during the 8 years that FEI was under Cost of service.

17.10.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 1.17.10.

17.11 Please provide further discussion of how the regulated utility is required to 'consistently achieve greater efficiencies in order to earn its allowed return', and provide quantification of the annual size of the 'greater efficiencies' that are required to earn the allowed return.

Response:

Using FEI's current PBR Plan as an example, FEI is required each year to achieve a productivity improvement factor (PIF) of 1.1%. That is, in each successive year of the PBR Term, FEI is required to achieve a further 1.1% savings just to achieve its allowed ROE (this is separate from the 50% reduction in FEI's growth factors under the PBR formula which acts as an incremental productivity improvement factor and is not considered in the analysis below).

Assuming zero inflation and customer growth and with a pre-amalgamation 2013 O&M Base of $197.3 million, the following table shows the annual and cumulative productivity savings required to achieve the allowed return, all else equal. The annual savings requirements are even greater when Vancouver Island and Whistler are included.

	Annual		Cumulative
($000s)	PIF	O&M	PIF
2013	-	197,299	-
2014	(2,170)	195,129	(2,170)
2015	(2,146)	192,982	(4,317)
2016	(2,123)	190,859	(6,440)
2017	(2,099)	188,760	(8,539)
2018	(2,076)	186,684	(10,615)
2019	(2,054)	184,630	(12,669)

18. Reference: Exhibit B-1, Appendix B, Pages 76 and 77

emissions and in 2008 passed a carbon tax. The Commission found reason to believe that FEI's risk had increased as such policies would discourage the use of natural gas. However, in its most recent 2013 Decision, the Commission indicated that the risks associated with provincial government climate and energy policies were not as great as

originally thought, citing collapse of the Western Climate Initiative and the inactivity in emissions trading; and that the carbon tax had not posed a significant threat as it has remained flat at $1.50 per GJ with no plans to raise it. On this point, the Commission determined that FEI had actually become less risky than it was perceived to be in 2009.[125] In my opinion, the risks posed by climate initiatives remain at both the provincial and municipal level, and are aggressive both in a Canadian and North American context.

5) Political and Regulatory Risk – Challenging - FEI continues to operate in a political environment where climate change initiatives are at the forefront and the use of fossil fuels for water heating and space heating is discouraged, though natural gas as a transportation fuel and for LNG export is garnering some political support. FEI is also subject to aboriginal rights issues that impact its political and regulatory environment.

18.1 Is it the author's opinion that the risk has increased, decreased or remained the same from the 2013 Decision?

Response:

The scope of Mr. Coyne's testimony in the GCOC proceeding was limited to matters pertaining to the Automatic Adjustment Mechanism, and did not relate to a review of FEI's business risk. In this proceeding, Mr. Coyne was not engaged by FEI to provide an in-depth comparison of FEI's business risk, relative to the risks that existed at the time of the 2012 GCOC application, but rather FEI's current risk profile and how it compares to the proxy group companies. However, Mr. Coyne has conducted a high-level comparative review of FEI's risk profile relative to 2012. Mr. Coyne generally finds that the business risks that the Commission identified as long term risks in its 2013 GCOC Decision continue to present as long term business risks to FEI today. Mr. Coyne is aware that municipalities are increasingly adopting policies and practices to combat climate change in the energy, building construction, and HVAC industries among others; and that consumer behavior is increasingly influenced by these policies. Mr. Coyne has not assessed whether this expansion of policies and the increasing change in customer behavior was already factored into the last ROE assessment, or whether these developments changed FEI's risk trajectory. But, Mr. Coyne has observed that these risks continue to be significant and do not appear to have diminished.

19. Reference: Exhibit B-1, Appendix B, Page 77

> 1) Operating Risks – Good - FEI operates in a province characterized by positive economic, population and employment growth, and household income growth. As shown in Table 13 previously in my testimony, BC's service territory is robust and compares favorably to the other seven Canadian provinces in my analysis, sharing very similar demographics to Ontario and Alberta (though Alberta's growth statistics are somewhat higher). FEI is the largest gas utility in BC with a large residential customer base. BC recognizes 285 different aboriginal First Nations, Bands and Tribal Councils in the province which creates operational challenges in its jurisdiction with respect to the potential for land rights claims by aboriginal groups.

19.1 Please confirm or otherwise explain that costs related to aboriginal land rights claims would likely be borne by the ratepayer and not by the shareholder under either cost of service or PBR.

Response:

Please refer to the responses to CEC IRs 1.7.1 and 1.7.2.

19.1.1 If not confirmed, does FEI have no recourse to the ratepayer for operational costs related to the challenges in its jurisdiction with respect to the potential for land rights claims by aboriginal groups?

Response:

Please refer to the response to CEC IR 1.19.1.

19.1.2 Please provide a discussion of how the operational risks may be viewed in comparison to utilities in the United States.

Response:

As Mr. Coyne states in his testimony, and as referenced above, FEI operates in a service territory that is on par with most of its U.S. peers. However, growth opportunities in the service territory are impacted by climate policies and trends in new home construction. As Table15, on p. 81 of Mr. Coyne's testimony illustrates, FEI's operating risk is ranked "Good," whereas the U.S. Proxy Group Average is ranked slightly higher as "Excellent/Good". Companies that received higher rankings received them as a result of the quality of opportunities for gas distribution growth in their service territories. For example, New Jersey Resources operates in a high growth service territory, where gas realizes a significant price advantage over electricity, and new home construction is predominantly (95%) natural gas. New Jersey Resources received a ranking of "Excellent" for operating risks. South Jersey Industries and WGL Holdings received similar rankings in the operating risk category for much the same reasons. Please refer to Mr. Coyne's Appendix A, pp. A-1 to A-15 for the complete comparative assessment of FEI's operating risks relative to the U.S. proxy group companies.

20. Reference: Exhibit B-1, Appendix B, Pages 65 and 77

2) Gas Supply and Infrastructure Risk – Good - FEI relies heavily on a single pipeline, Westcoast. Though natural gas is relatively abundant in the province, there is increasing potential for price increases, or that access to gas at current prices may not be sustainable. Growing demand for natural gas in the Pacific Northwest and

limited supply infrastructure in the region could lead to deliverability constraints due to inadequate infrastructure in the region.

Gas supply risk relates to both the availability of gas supply and the potential for gas supply interruption. Both measures are highly dependent on the infrastructure in place to process and transport the natural gas to load centers. The risk of a supply shortfall in BC is currently deemed to be remote given the discovery of large shale reserves in northeastern BC, however, the ability to gain profitable access to markets at current price levels and with existing infrastructure may slow BC shale production. U.S. shale gas production is supplying a growing portion of eastern markets that had historically accessed gas supply from the Western Canadian Sedimentary Basin (WCSB). Overall, shale gas reserves are substantial in BC, but it is important to note that the market price for that gas must rise and new infrastructure built before these reserves will be more fully exploited.

20.1 Does the author believe that the risk of gas supply and infrastructure is expected to move away from 'remote' in the near term? Please explain.

<u>Response:</u>

In response, it is necessary to break gas supply down into its commodity and infrastructure components. As Mr. Coyne indicated, gas supply is relatively abundant in the Pacific Northwest and the risk of a supply shortfall (gas commodity) is deemed remote in the near term. However, as Mr. Coyne has indicated in his testimony on p. 66, and in his response to CEC IR 1.9.4, BC was expected to experience a regional supply shortfall (infrastructure) as early as 2014/2015 that grows over time even in the "Expected Case." As noted by the NWGA in its regional gas outlook (Attachment 9.1, provided in response to CEC IR 1.9.1. p.18), there are several key variables that determine the magnitude and timing of these constraints:

- When, where and how much natural gas the region will require to generate electricity;
- Whether large industrial and/or LNG export loads proposed for the region materialize; and

- The impact of the legal and regulatory environment on the ability to build new or expand existing infrastructure in a timely manner. (Projects can take three to five years to develop, making foresight imperative).

The NWGA observes: Under the expected and high demand cases, peak day loads could stress the system, approaching or exceeding the region's infrastructure capacity within the forecast horizon (Attachment 9.1, provided in response to CEC IR 1.9.1, p.16).

Though it is Mr. Coyne's expectation that the relatively low levels of gas transmission system stress in the early years will not move the dial on his assessment of gas supply and infrastructure risk in the near term, without the addition of infrastructure in the region, Mr. Coyne would expect this risk to become more pronounced over the next several years such that it could no longer be characterized as remote.

20.2 As US shale gas pushes at traditional Canadian markets, what happens to the price in Canada at AECO and Station 2?

Response:

FEI expects that, all else equal, as US shale gas reduces traditional markets for producers who bring gas to the AECO/NIT and Station 2 markets, prices at these hubs would decrease relative to other hubs such as Henry Hub. However, western Canadian producers will not continue to produce at any price level and decreases in production in some gas plays, such as Horn River in northern BC for example, have already occurred and additional displacement is more likely to see further reduction in production rather than further sustained price reductions. Furthermore, other markets can replace these traditional markets for western Canadian producers, such as oil sands demand, industrial growth and LNG exports. Therefore, future prices for AECO/NIT and Station 2 are uncertain and will be determined by the various supply and demand dynamics that continue to evolve over time.

21. Reference: Exhibit B-1, Appendix B, Page 81

				Short-term Risks		Long-term Risks					
Company	Credit Rating	Total Assets (billions)	Percent Regulated	Revenue Stabilization	Cost Recovery	Operating Risk	Supply and Infrastructure Risk	Price and Volatility Risk	Volume Demand Risk	Political and Regulatory Risk	Business Risk Determination in Relation to FEI
FEI	A3 or A-	$6.9	100%	Excellent	Excellent	Good	Good	Fair	Challenging	Challenging	
Atmos Energy	A-	$7.6	98%	Good	Excellent	Good	Excellent	Good	Good	Good	Lower Risk
New Jersey Resources	A	$2.8	72%	Excellent	Good	Excellent	Excellent	Excellent	Excellent	Excellent	Lower Risk
Northwest Natural Gas Company	A+	$3.1	89%	Excellent	Good	Good	Good	Excellent	Good	Excellent	Lower risk
Piedmont Natural Gas Co.	A	$3.6	97%	Good	Excellent	Good	Excellent	Excellent	Good	Excellent	Lower risk
South Jersey Industries	BBB+	$1.8	68%	Excellent	Excellent	Excellent	Excellent	Excellent	Excellent	Good	Comparable[126]
Southwest Gas Corporation	A-	$4.4	94%	Excellent	Excellent	Good	Excellent	Good	Challenging	Fair	Comparable
WGL Holdings Inc	A+	$4.1	85%	Excellent	Excellent	Excellent	Excellent	Good	Good	Good	Lower risk
U.S. Proxy Group Average	A/A-	$3.2	88%	Excellent	Excellent	Excellent/Good	Excellent	Excellent/Good	Good	Good	Lower Risk

21.1 Please provide the time frame for 'short term risk' and 'long term risk' that is used in this table.

Response:

By 'Short-term' risks, Mr. Coyne is referring to the regulatory protection the company enjoys in minimizing the potential for loss or significant lag between the incurrence of costs and their ultimate recovery; or for losses due to weather or declines in customer use. We would expect all costs to be recovered within a year or two. Rankings relate to the measure of regulatory protection against losses and the minimization of regulatory lag.

21.2 Please confirm that the most significant long term risks facing FEI relate to Volume Demand Risk and Political and Regulatory risk.

Response:

Confirmed.

22. Reference: Exhibit B-1, Appendix B, Page 83

Table 16: Awarded Returns Comparable Canadian Utilities

	Credit Rating	ROE	Equity Ratio	Weighted Equity Return
FortisBC Energy Inc.	**A3 (Moody's)**	**8.75%**	**38.5%**	**3.37%**
ATCO Gas	A	8.30%	38.0%	3.15%
Enbridge Gas Distribution Inc.	A-	9.30%	36.0%	3.35%
Union Gas	BBB+	8.93%	36.0%	3.21%
Gaz Métro[127]	A	8.90%	38.5%	3.43%
AVERAGE CDN PEERS		**8.86%**	**37.10%**	**3.29%**

22.1 Please confirm that the awarded returns are those currently in place in each of the utilities.

Response:

Confirmed.

22.2 When were the awards last determined for each utility?

Response:

The following table shows the case and date of the last award for each company:

Company	Year and Case Where Award was Last Determined
FortisBC Energy Inc.	British Columbia Utilities Commission, Letter L-1-14, Return on Equity for the Benchmark Utility for the Year 2014, January 10, 2014
ATCO Gas	Alberta Utilities Commission, Decision 2191-D01-2015, 2013 Generic Cost of Capital, March 23, 2015
Enbridge Gas Distribution Inc.	Ontario Energy Board, Cost of Capital Parameter Updates for 2015 Cost of Service Applications, November 20, 2014
Union Gas	Ontario Energy Board, Decision and Rate Order, EB-2011-0210, January 17, 2013, at 23.
Gaz Metro	Regie de l'energie, Decision D-2015-076, R-3879-2014 Phase 3 Interlocutory Decision, May 26, 2015

22.3 Please provide the awarded ROEs for each company for each of the last 10 years.

Response:

The following table shows the awarded ROEs for each company for the last 10 years:

Authorized Rate of Return on Common Equity										
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Fortis BC Energy Inc.	8.80	8.37	8.62	8.99	9.50	9.50	9.50	8.75	8.75	8.75
ATCO Gas	8.93	8.51	8.75	9.00	9.00	8.75	8.75	8.30	8.30	8.30
Enbridge Gas Distribution Inc.	8.74	8.39	8.39	8.39	8.39	8.39	8.39	8.93	9.36	9.30
Union Gas	9.63	8.54	8.54	8.54	8.54	8.54	8.54	8.93	8.93	8.93
Gaz Metro	8.95	8.73	9.05	8.76	9.20	9.09	8.90	8.90	8.90	8.90

Source: Data gathered by Concentric

22.4 Please provide the Equity Ratios for each company for each of the last 10 years.

Response:

The table below shows the awarded Equity Ratios for each company for the last 10 years:

Authorized Common Equity Ratio										
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Fortis BC Energy Inc.	35.00	35.00	35.00	35.00	40.00	40.00	40.00	38.50	38.50	38.50
ATCO Gas	38.00	38.00	38.00	39.00	39.00	39.00	39.00	38.00	38.00	38.00
Enbridge Gas Distribution Inc.	35.00	36.00	36.00	36.00	36.00	36.00	36.00	36.00	36.00	36.00
Union Gas	35.00	36.00	36.00	36.00	36.00	36.00	36.00	36.00	36.00	36.00
Gaz Metro	38.50	38.50	38.50	38.50	38.50	38.50	38.50	38.50	38.50	38.50

Source: Data gathered by Concentric

23. Reference: Exhibit B-1, Appendix B, Page 84

> the utility from uncontrollable cost fluctuations. Further, both jurisdictions have transitioned to PBR ratemaking. I generally consider the ratemaking protection in Alberta to be comparable to that of BC. Of late, however, the AUC's recent decision in its utility asset disposition ("UAD") proceeding, where it imposes a strict interpretation of the "used and useful principle" for assets in rate base, and its most recent generic cost of capital decision, which lowered ROE and equity ratios for all utilities, have reduced predictability, and in the case of the UAD Decision presents new uncertainties.
>
> Despite the recent adverse regulatory trend in Alberta, the province's high natural gas capture rate, its strong population growth, and the lack of gas supply risk, positions Alberta at the lower end of the risk spectrum for the operation of a natural gas distribution utility in Canada. Accordingly, I consider FEI to operate in a higher risk environment than Alberta's utilities, and accordingly is higher risk than its peer, ATCO Gas.

23.1 Please confirm that the AUC has the mandate to ensure that customers receive safe and reliable service at just and reasonable rates.

<u>Response:</u>

Confirmed.

24. Reference: Exhibit B-1, Appendix B, Pages 87 and 88

> With regard to the operating companies in the U.S. proxy group, on balance, there are no fundamental differences in business risk between FEI and the U.S. proxy group that would render comparisons inappropriate. As discussed above, FEI has higher risk than the U.S. proxy group on several factors (primarily attributable to the intense competitive environment natural gas faces with electricity in the Province and the challenging environmental initiatives in BC). But FEI also faces volumetric/demand risk resulting from the downward trend in new housing starts and low capture rates for new home construction. Other factors contributing to FEI's heightened business risk profile are its

> - The U.S. proxy group is less risky than FEI, but not to a degree that warrants a risk adjustment to the ROE.

24.1 Do US companies in the proxy group face any competition?

Response:

Yes.

24.1.1 If yes, please provide an overview of the types of competition that companies in the US proxy group face.

Response:

Please review Mr. Coyne's Business Risk Assessment in Appendix A to his Testimony. The types of competition that companies in the U.S. proxy group face are summarized in Mr. Coyne's Proxy Group Risk Assessment on pp. A-1 through A-14. Generally, Mr. Coyne finds that the risk for natural gas distribution is greater in BC than in any jurisdiction in the U.S. as a result of the green policies that have been enacted in Canada and BC, , that discourage the use of natural gas. Further, no other U.S. jurisdiction faces the level of competition that FEI faces from low-priced electricity. In the U.S. competition occurs at the industrial level, where fuel switching and bypass are sometimes significant concerns. The warmer climates have lower gas penetration rates and a higher percentage of homes built that rely solely on electricity. Because of the prevalence of coal in the U.S., natural gas is generally viewed as a much cleaner fuel and is encouraged rather than discouraged. Note the EPA Clean Power Plan is viewed as a boon for natural gas producers as the U.S. tries to gradually wean itself off dirty oil and coal. The competitive characteristics of the U.S. proxy group companies are more fully addressed in the Risk Templates of Mr. Coyne's Business Risk Appendix from pp. A-58 to A-87.

25. Reference: Exhibit B-1, Appendix C, Page 3

Table C-2: Amalgamated FEI's Business Risk as Compared to 2012 Benchmark Utility

Business Risk Category	Risk Factor	Total risk status since 2012, (all business changes incl. amalg.)	Risk status change due to amalgamation alone	Ranking of risk
Regulatory		**Same**		**1**
	Regulatory uncertainty and lag	Same	Same	
	Deferral accounting	Same	Same	
	Administrative penalties	Same	Same	
Energy Prices		**Same**		**2**
	Commodity prices	Lower	Same	
	Commodity price volatility	Higher	Same	
	Upfront and installation costs	Same	Same	
Market Shifts		**Same**		**2**
	New technology and energy forms	Same	Same	
	Perception of energy	Same	Same	
	Housing types	Same	Same	
	Changes in use per customer	Same	Same	
	Changes in the capture rates	Same	Same	
Political		**Higher**		**2**
	Energy policy and legislation	Same	Same	
	GHG emissions reductions initiatives and local governments policies	Higher	Same	
	Carbon tax	Same	Same	
	Aboriginal rights	Higher	Same	
Business Profile		**Same**		**2**
	Type and size of the utility	Same	Same	
	Energy product offering	Same	Same	
	Service area and customer profile	Same	Same	
Economic Conditions		**Same**		**2**
	Overall economic conditions	Same	Same	

Business Risk Category	Risk Factor	Total risk status since 2012, (all business changes incl. amalg.)	Risk status change due to amalgamation alone	Ranking of risk
Operating		Same		3
	Infrastructure integrity	Same	Same	
	Third party damages	Same	Same	
	Unexpected events	Same	Same	
Energy Supply		Higher		4
	Availability of supply	Same	Same	
	Security of supply	Higher	Higher	

25.1 Please confirm that the contributors to the change in risk assessment from the 2012 Benchmark Utility are related to Commodity Prices, Commodity Price Volatility, GHG emissions reductions initiatives and local government policies and aboriginal rights and security of supply.

Response:

Confirmed. The security of supply risk increase relates to the transition of FEVI's and FEW's security of supply risk to the amalgamated FEI service area while the rest of the changes relate to the political and market developments since 2012. FEI considers that the political risk change is more pronounced than other risk changes. Please also note that the recent developments in provincial climate policies (for instance the recently published recommendations from the Climate Leadership Team) indicate that provincial political risk may be trending even higher than previously assessed. The recent announcement by the City of Vancouver regarding its energy strategy stands to have potentially significant implications for FEI beyond those described in Appendix 3. Please refer to the response to BCUC IR 1.4.3 for more information.

25.1.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 1.25.1.

25.2 Please confirm that the Commodity Prices and Commodity Price Volatility effectively balance each other out, so that the risk for Energy Prices is essentially the same as the risk assessment in 2012.

Response:

Confirmed. The overall risk for Energy Prices is the same as the risk assessed in 2012.

25.2.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 1.25.2.

26. Reference: Exhibit B-1, Appendix C, Page 4

- *Regulatory*: The Commission's jurisdiction is confined to what is conferred by the Utilities Commission Act (*Act*), but within that framework has significant discretion in the exercise of those powers. FEI is dependent on regulatory approvals of rates that determine its revenues and cost recoveries. The Commission establishes the level of return that is allowed to be included in rates, and establishes depreciation rates that determine a utility's ability to recover invested capital. Regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty which in itself gives rise to the risk 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 its fair return, or that necessary investments are not approved. Compared to previous periods, the 2014 PBR Decision included some additional regulatory uncertainty and risk, although the broader regulatory constructs that supported FEI's characterization of regulatory risk in 2012 remain in place. FEI has thus assessed its overall regulatory risk as being similar to what it was in 2012, with the potential to be higher over the term of PBR.

26.1 Please confirm that Performance Based Ratemaking provides for increased upside opportunity for the shareholder.

Response:

Please refer to the response to CEC IR 1.17.10.

26.2 Please provide FEI's views as to whether or not it is likely to have increased or decreased returns relative to its allowed ROE over the PBR period, and provide quantification of FEI's expectations.

Response:

Please refer to the response to CEC 1.17.10 and BCUC IR 1.31.1.

26.3 Please provide FEI's 2014 and 2015 annual reviews including the proposed cost sharing and impact on ROE.

Response:

FEI has provided in this response the proposed cost sharing and impact on ROE. To the extent that the question was asking for the Annual Review evidentiary record to be refiled in this proceeding, FEI respectfully declines for similar reasons to those expressed in response to CEC IR 1.17.9 (in which CEC requested the PBR Application to be re-filed).

FEI's pre-amalgamation final earnings sharing amount related to 2014 O&M and capital variances was $3.657 million which would increase ROE by 0.36% over the approved, all else equal.

FEI's post-amalgamation projected earnings sharing amount related to 2015 O&M and capital variances was $4.752 million which would increase ROE by 0.30% over the approved, all else equal.

27. Reference: Exhibit B-1, Appendix C, Page 8

Table C-3: Amalgamated FEI's Business Profile[7]

Type of Utility	Local Distribution Company	
Energy Product Offering	Natural gas, biomethane, propane[8]	
Service Area	Mainland, Vancouver Island and Whistler	
Rate Base	$3,661 million	
Sales/Transportation Volumes	176,035 TJ	
Average Number of Customers	970,389	
Net Customer Additions	10,712	
Customer Growth Rate	~1%	
Customer Profile by Demand	<u>TJ</u>	<u>Percentage</u>
Residential	73,067.8	42%
Commercial	55,573.1	32%
Industrial	47,393.6	26%
Customer Profile by Sales Revenue	<u>($000s)</u>	<u>Percentage</u>
Residential	814,408	60%
Commercial	454,626	33%
Industrial	94,386	7%

Notes to Table C-3:
- Residential includes Rate Schedule 1. Commercial includes Rate Schedules 2, 3, 23
- Industrial includes Rate Schedules 4, 5, 6, 7, 22, 25, 27, 46
- With the exception of the rate base amount, all the numbers are for non-bypass customers only. Bypass Transportation volume equals 31,352 TJs and Revenue equals $29,802 thousand

The fact that the majority of FEI's delivery margin revenue is generated from residential customers is significant because FEI faces its greatest challenges[9] in the residential market.

Figure C-1 below demonstrates that in FEI's residential and commercial sectors, space and water heating are the dominant end uses, accounting for about 83 percent and 71 percent of the energy consumption respectively for each sector.

27.1 Please include the 'Customer Profile by Number of Customers' in the above table.

<u>Response:</u>

Please refer to the response to BCUC IR 1.1.1.1.

27.2 Please provide the historical trends for demand, sales revenue and number of customers over the last 10 years for each customer group.

Response:

Please refer to the response to BCUC IR 1.1.1.1 for the historical demand, sales revenue and average customers.

27.3 Please provide FEI's forecast for demand, sales revenues and number of customers over the PBR period.

Response:

In the table below, FEI has provided the approved 2014, 2015 and 2016 non-bypass demand, sales revenues and average number of customers which are on an equivalent basis to the numbers provided in Table C-3 of Appendix C.

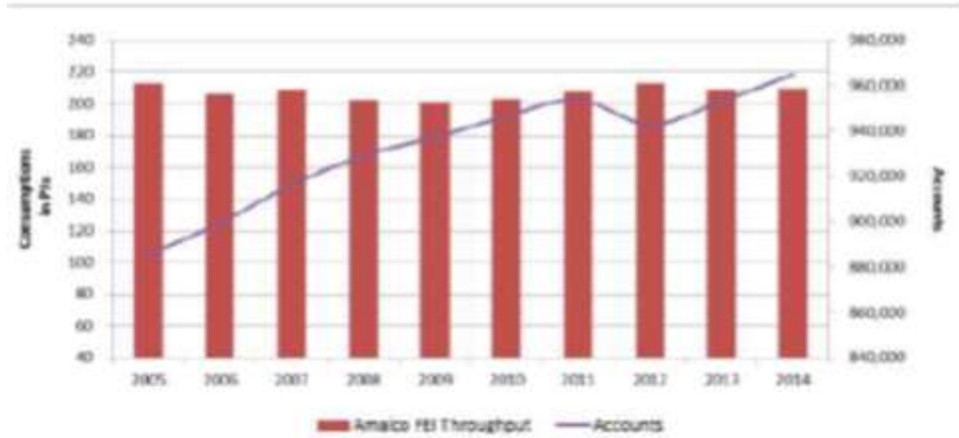
	2014 Approved	2015 Approved	2016 Approved
Total Demand (PJs)	188	176	178
Sales Revenues ($000s)	$ 1,290,928	$ 1,363,420	$ 1,210,230
Average Number of Customers	952,060	970,389	979,093

For the remainder of the PBR term (2017 to 2019), FEI has used simple interpolation of the 2014 Long-Term Resource Plan results since the 2014 Long-Term Resource Plan forecast was developed using milestone years (every five years, starting in 2011). The table below provides the demand, which includes bypass customers but excludes NGT customers, and projected year-end customers as contained in the 2014 Long-Term Resource Plan. The 2014 Long-Term Resource Plan forecast did not calculate revenue so that line is shown as N/A.

	2017 Forecast	2018 Forecast	2019 Forecast
Total Demand (PJs)	200	200	200
Sales Revenues ($000s)	N/A	N/A	N/A
Year End Total Customers	979,915	987,087	994,258

28. Reference: Exhibit B-1, Appendix C, Page 10

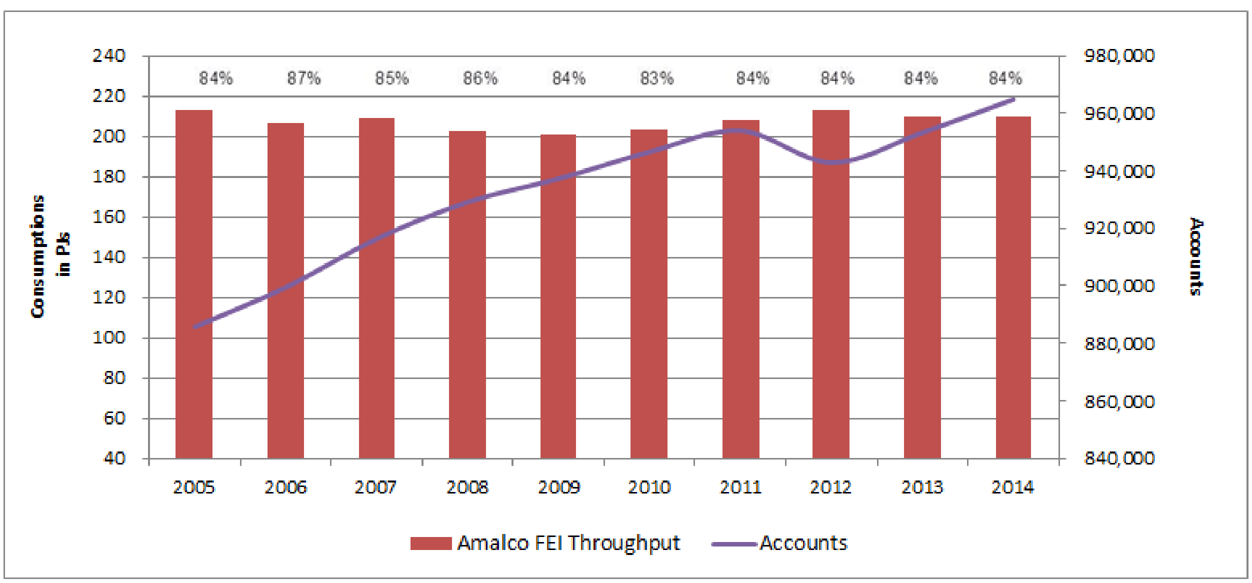
Figure C-3: Amalgamated FEI's Total Throughput (Normalized Throughput vs. Customer Accounts)



28.1 Please distinguish FEI the portion of FEI's throughput in the above graph from that of Amalco.

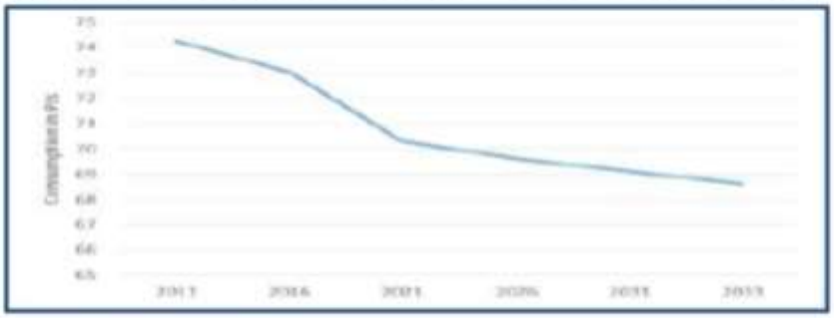
Response:

FEI has revised Figure C-3 below to include the portion of pre-amalgamation FEI's throughput displayed as a percentage of the combined pre-amalgamation FEI, FEVI and FEW throughput above each bar.



29. Reference: Exhibit B-1, Appendix C, Page 12

Figure C-6: Outlook of Amalgamated FEI Residential Throughput Levels



Source: 2014 LTRP – Residential Sector

29.1 Please provide the Outlook of Amalgamated Total Throughput levels to 2033.

Response:

Please refer to the response to BCUC IR 1.19.4. Note that the totals in that response are total residential, commercial and industrial throughput, excluding NGT.

29.2 Please provide the Outlook of Amalgamated Commercial Throughput levels to 2033.

Response:

The Outlook of Amalgamated Commercial Throughput levels is provided below per each of the milestone years.

	2011	2016	2021	2026	2031	2033
Commercial Throughput (PJ)	55	57	59	61	63	64

29.3 Please provide the Outlook of Amalgamated Industrial Throughput levels to 2033.

Response:

The Outlook of Amalgamated Industrial Throughput levels to 2033 is provided below for each of the milestone years.

	2011	2016	2021	2026	2031	2033
Industrial Throughput (PJ)	66	71	70	69	68	68
source: 2014 LTRP						

30. Reference: Exhibit B-1, Appendix C, Page 13

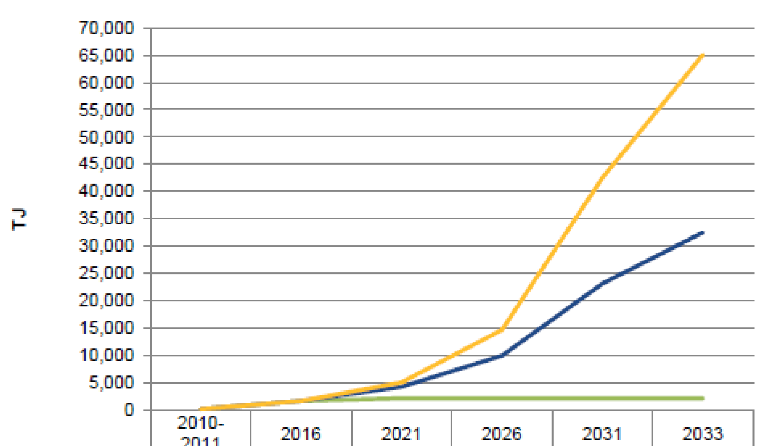
> FEI has, in recent years, responded to the changing energy environment in BC and the declining throughput in its core business by undertaking new initiatives. One of those initiatives, Natural Gas for Transportation (NGT), has been identified as a potential new source of load outside of FEI's core market. Table C-4 provides an estimate of the additional volumes forecast to be added to the system as a result of Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) incentive funding and overall efforts to add NGT load to the system.
>
> **Table C-4: FEI's NGT Demand Forecast (2015-2017)**
>
> | Demand Volumes (TJ) | 2015 | 2016 | 2017 |
> |---|---|---|---|
> | CNG Demand | 480 | 586 | 616 |
> | LNG Demand | 435 | 1,560 | 3,847 |
> | Total NGT Demand | 915 | 2,146 | 4,463 |
>
> A continuation of the current low oil prices may hinder FEI's efforts to expand the NGT demand in its service territory.

30.1 Please provide an Outlook for NGT demand through to 2033.

Response:

FEI's most recent long term demand forecast for NGT demand is included in the Company's 2014 Long Term Resource Plan (LTRP), which was filed with the Commission on March 25, 2014. Figure 3-13 in Section 3.3.7 of the LTRP provides the long term NGT demand forecasts through to 2033 and is copied below for reference.

Figure 3-13: Annual NGT Demand – All Scenarios[60]



	2010-2011	2016	2021	2026	2031	2033
Low	195	1,676	2,168	2,168	2,168	2,168
Reference	195	1,676	4,267	9,946	23,183	32,522
High	195	1,676	5,075	14,689	42,518	65,045

For two of the three scenarios shown, this potential demand from using natural gas as a transportation fuel has declined somewhat from the potential demand growth previously identified in FEI's 2010 LTRP (and included in the 2012 GCOC proceeding evidence). The demand scenarios presented in the 2010 LTRP reached 13,000 TJ in the Low [NGV] Growth scenario, 30,000 TJ in the Favourable [NGV] Environment scenario and 36,000 TJ in the Aggressive [NGV] Adoption scenario, all by the year 2030.

30.2 Please confirm that the reason low oil prices may hinder FEI's efforts to expand the NGT demand in its service territory is because oil competes with natural gas in the transportation sector on price.

Response:

The primary markets that FEI is targeting for natural gas use all use diesel fuel as the incumbent fuel today (i.e.,mine haul trucks, on road trucks, marine vessels in the Emission Control Areas). Diesel prices and oil prices are strongly correlated, thus the reference to 'current low oil prices'.

30.2.1 If not confirmed, please provide the reason that the current low oil prices may hinder FEI's efforts to expand the NGT demand in its service territory.

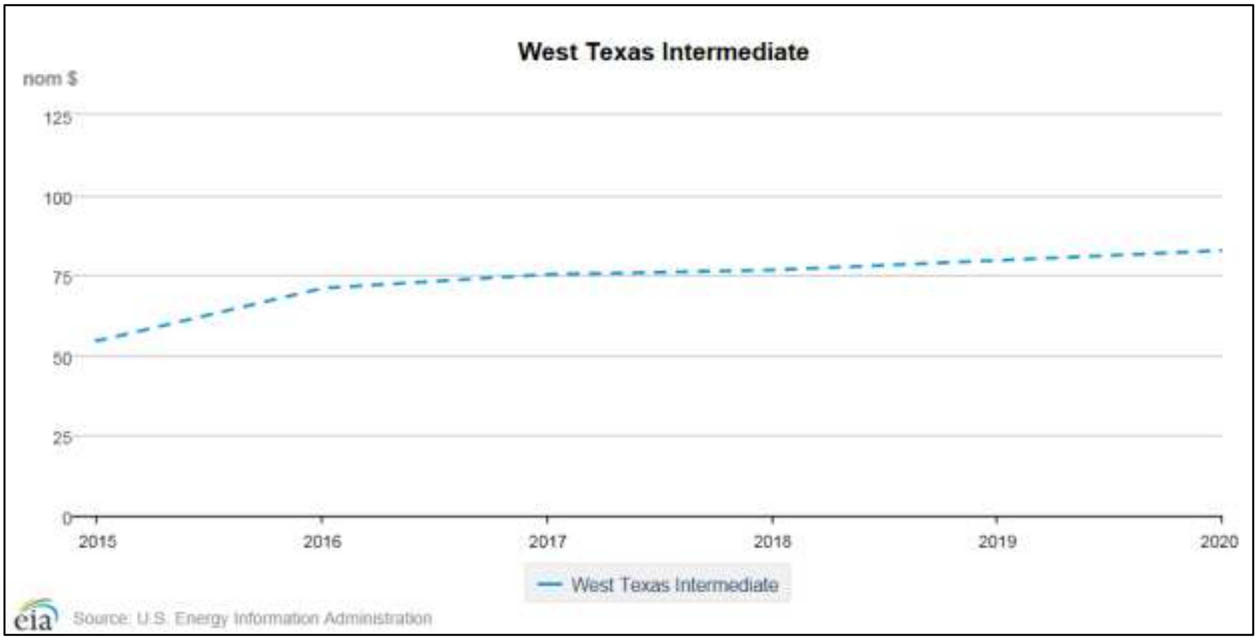
Response:

Please refer to the response to CEC IR 1.30.2.

30.3 Please provide FEI's expectation for oil prices in the next five years.

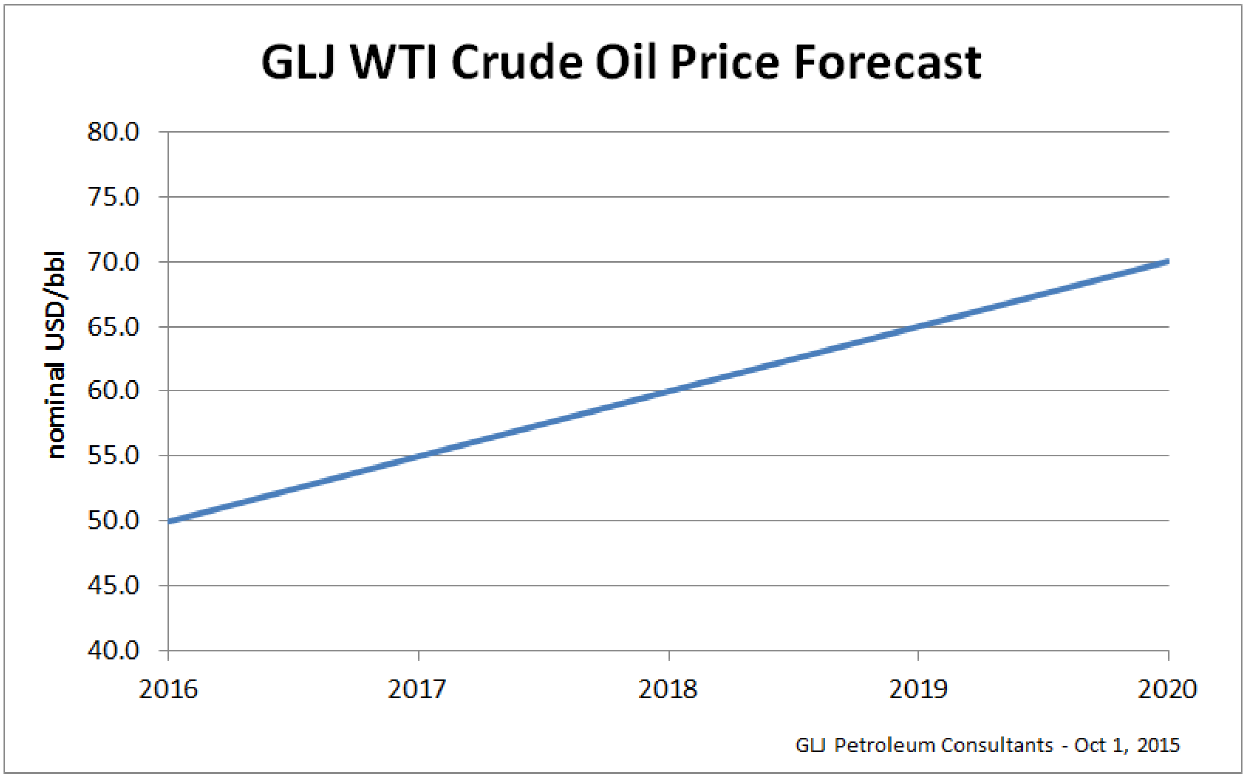
Response:

FEI does not produce its own oil price forecast but relies on third party forecasts. The following figure illustrates the West Texas Intermediate (WTI) crude oil price forecast from the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2015 report[9].



The following figure illustrates the WTI crude oil price forecast from GLJ Petroleum Consultants for the next five years.

9 U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2015 - April 14, 2015.



30.4 Please provide FEI's forecast or expectation for natural gas prices in the next five years.

Response:

Please refer to the response to CEC IR 1.10.9.

30.5 Please confirm that natural gas offers advantages relative to oil on other criteria.

Response:

Please refer to the response to CEC IR 1.30.2 regarding the reference to the oil prices in the preamble. The advantages of natural gas in FEI's target transportation market (mine haul trucks, on road trucks, marine vessels in the Emission Control zones) should be compared with its substitute fuel which is mainly diesel fuel. In addition to the relative annual fuel cost savings, natural gas can reduce the GHG emissions of the vehicles on a lifecycle basis by 15 to 25 percentage points compared to gasoline or diesel. Further, natural gas vehicles emit less noise on a decibel basis than comparable diesel trucks, hence generate less noise pollution.

Alternatively, where natural gas vehicles are at a disadvantage to diesel vehicles is the higher initial capital costs of natural gas vehicles compared to comparable diesel powered vehicles. Further, the fueling infrastructure is still in the nascent stages of development, which is required to provide fueling to fleets that operate along strategic transportation corridors. The build out of CNG and LNG fueling infrastructure is required to permit further penetration and adoption of natural gas vehicles.

A limitation regarding development of the NGT market is the availability of suitable OEM supplied NG engines for target applications. FEI's initial success in penetrating the heavy duty truck market was dependent on the availability of a 15 litre engine developed by Westport Innovations and made available through OEM offerings from Peterbilt and Kenworth. This engine was withdrawn from the market in late 2013 and no suitable replacement engine has been introduced. As a result, market penetration in the heavy duty truck segment has been limited.

30.5.1 If confirmed, please list the criteria in which natural gas may be considered a superior option to oil in the transportation sector.

<u>Response:</u>

Please refer to the response to CEC IR 1.30.5.

31. Reference: Exhibit B-1, Appendix C, Page 13

> The addition of NGT volumes is a favourable development for customers in terms of representing a revenue stream. However, they do not materially affect FEI's overall risk profile. For instance, FEI's NGT demand for 2015 is forecast to be around 0.915 PJ which represents less than 1 percent of amalgamated FEI's total throughput. Even if NGT expands to its potential over the next few years, its share of total throughput would remain relatively small.

31.1 Please provide the forecast change in the residential throughput for 2015, 2016 and 2017.

Response:

The residential throughput change for 2015 through 2017 is provided in the table below.

FEI has used the following data sources to provide the requested throughput tables in CEC IRs 1.31.1 through 1.31.3.

- 2014 Approved throughput as provided in the Compliance Filing for BCUC Order G-106-15.
- 2015 Approved throughput as provided in the Compliance Filing for BCUC Order G-106-15.
- 2016 Approved throughput as provided in the Compliance Filing for BCUC Order G-193-15.
- 2017 Forecast throughput as provided in the data tables used to produce Figure 3-7 through Figure 3-9 in the 2014 Long-term Resource Plan Application.

Since the 2016 and 2017 Forecasts were prepared using different methodologies, they cannot be directly compared.

FEI	2014 Approved	2015 Approved	2016 Approved	2017 Forecast
Residential (TJs)	74,029	73,068	72,466	72,485
Annual Change (TJs)		(961)	(602)	19

31.2 Please provide the forecast change in the commercial throughput for 2015, 2016 and 2017.

Response:

The commercial throughput change for 2015 through 2017 is provided in the table below using the same sources as indicated in response to CEC IR 1.31.1. Since the 2016 and 2017 Forecasts were prepared using different methodologies, they cannot be directly compared.

FEI	2014 Approved	2015 Approved	2016 Approved	2017 Forecast
Commercial (TJs)	55,920	55,573	55,102	57,407
Annual Change (TJs)		(347)	(471)	2,305

31.3 Please provide the forecast change in industrial throughput for 2015, 2016 and 2017.

Response:

The industrial throughput change for 2015 through 2017 is provided in the table below.

The amounts below exclude NGT customers but include all bypass customers to align with the 2017 throughput included in Figure 3-9 in the 2014 Long-Term Resource Plan. Otherwise, the sources are as set out in the response to CEC IR 1.31.1. Since the 2016 and 2017 Forecasts were prepared using different methodologies, they cannot be directly compared.

FEI	2014 Approved	2015 Approved	2016 Approved	2017 Forecast
Industrial (TJs)	87,001	80,797	78,091	70,456
Annual Change (TJs)		(6,204)	(2,706)	(7,635)

32. Reference: Exhibit B-1, Appendix C, Page 15

Table C-5 summarizes the changes in leading economic indicators for four jurisdictions across Canada.

Table C-5: Economic Indicators for Four Jurisdictions in Canada (2012 to 2016)

	2012	2013	2014	2015	2016
British Columbia					
Real GDP (% change)	2.4	1.9	2.7	2.2	2.5
Unemployment (%)	6.8	6.6	6.1	6.0	5.8
Housing starts (1000 of units)	27.5	27.1	28.3	26.7	27.1
Alberta					
Real GDP (% change)	4.5	3.8	4.5	-0.9	2.0
Unemployment (%)	4.6	4.6	4.7	5.9	6.1
Housing starts (1000 of units)	33.3	36.1	40.5	36.5	35.9
Ontario					
Real GDP (% change)	1.7	1.3	2.2	2.1	2.5
Unemployment (%)	7.9	7.6	7.3	6.8	6.5
Housing starts (1000 of units)	77.4	60.9	58.3	66.4	68.8
Quebec					
Real GDP (% change)	1.5	1.0	1.4	1.7	2.1
Unemployment (%)	7.7	7.6	7.7	7.5	7.4
Housing starts (1000 of units)	47.2	37.6	38.9	38.2	38.2

Shaded area represents forecast data (2014 real GDP numbers are estimates).
TD Economics, July 2015, retrieved from:
http://www.td.com/document/PDF/economics/qef/ProvincialEconomicForecast_July2015.pdf

Housing starts are an important variable in determining residential customer additions. As seen in Table C-5, BC has the lowest housing starts numbers among major Canadian provinces and is expected to be faced with lower housing starts compared to 2014. Lower projected housing starts can be expected to make it more difficult for FEI to add new customers and throughput.

32.1 Please confirm that housing starts are equally important indicators in other provinces.

<u>Response:</u>

Confirmed.

32.1.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 1.32.1.

33. Reference: Canada Mortgage and Housing Corporation, Housing Market Information 'Housing Now', BC Region, 3rd Quarter, 2015

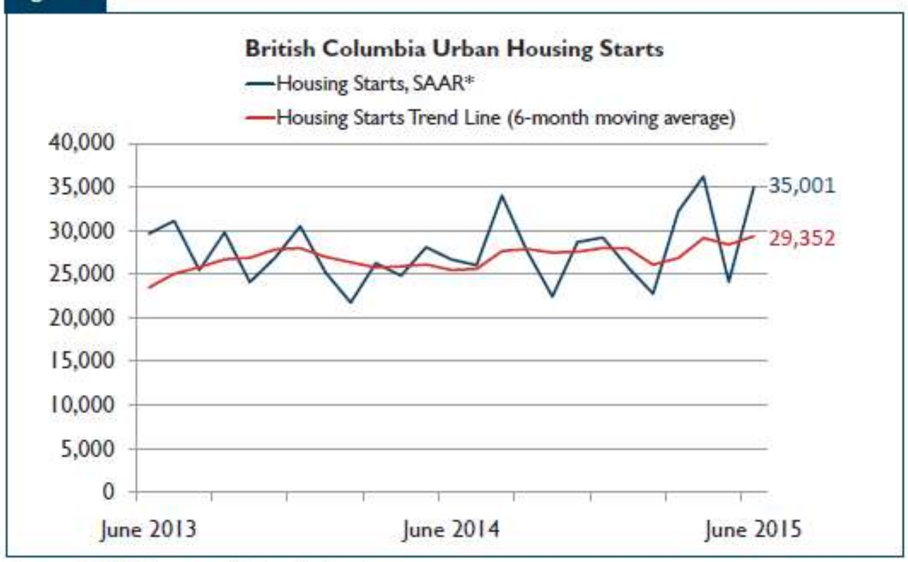
Date Released: Third Quarter 2015

New Home Market

Housing starts in British Columbia's urban centres[1] were trending at 29,352 units in June compared to 28,384 units in May, according to Canada Mortgage and Housing Corporation (CMHC). The trend is a six-month moving average of the monthly seasonally-adjusted annual rates (SAAR)[2] of housing starts (see Figure 1).

Robust new residential construction reflects demand for housing stemming from population growth and an active resale market. As well, inventories of completed and unabsorbed new

Figure 1



Source: CMHC Starts and Completions Survey

[1] Urban Centres are centres with populations of 10,000 or more people.

[2] Seasonally adjusted annual rates (SAAR) – Monthly housing starts figures are adjusted to remove normal seasonal variation and multiplied by 12 to reflect annual levels. By removing seasonal ups and downs, seasonal adjustment allows for a comparison from one season to the next and from one month to the next. Reporting monthly figures at annual rates indicates the annual level of starts that would be obtained if the monthly pace was maintained for 12 months. This facilitates comparison of the current pace of activity to annual forecasts as well as to historical annual levels.

Figure 3

Source: CMHC Starts and Completions Survey, for BC Census Metropolitan Areas and Census Agglomerations with at least 50,000 people.

33.1 Please provide the 2015 3rd Quarter Canada Mortgage and Housing Corporation Housing Market Information 'Housing Now' BC Region - http://www.cmhc-schl.gc.ca/odpub/esub/64151/64151_2015_Q03.pdf.

Response:

This response addresses CEC IRs 1.33.1 and 1.33.2.

Since the filing of the Application, TD Economics has issued a new provincial forecast which is provided as Attachment 33.1 for information purposes. Attachment 33.1 also contains the 2015 third Quarter CMHC Housing Market Information Report - BC Region, and the 2015 fourth Quarter CMHC Housing Market Outlook - BC Region Highlights, respectively.

33.1.1 Please confirm that the Canada Mortgage and Housing information indicates an increasing trend in urban housing starts rather than the decrease forecast by Canada Trust and included in the application.

Response:

Please refer to the table below for the comparative analysis of TD Economics July 2015 and October 2015 forecasts and CMHC 4th Quarter Market Outlook forecasts as well as CMHC 3rd Quarter Market Information 'Housing Now' data.

Comparative analysis of housing starts forecasts in BC (1000 of units).

	2014	2015	2016
TD Economics- July 2015	28.3	26.7	27.1
TD Economics – October 2015	28.3	32.5	28.7
CMHC 4th Quarter Market Outlook forecasts	28.3	31.3	30.8
CMHC 3rd Quarter Market Information data	28.3	29.3[10]	N/A[11]

The comparison of TD Economics forecast with CMHC 3rd quarter Market Information, 'Housing Now' Report is not appropriate. The "Housing Now" report only provides the actual data until June 2015 while TD Economics provides a forecast for the full year. In addition, as discussed in response to BCUC IR 1.23.1 and demonstrated in the table above, housing starts forecasts are volatile. TD Economics October forecast for 2015 is higher than the July 2015 forecast for the same year and indicates an increase in 2015 followed by a decline in 2016 and 2017 similar to the forecasts provided in CMHC 4th quarter Market Outlook Report.

Furthermore, TD Economics forecasts for 2016 in both the July 2015 and October 2015 revisions are in the range forecasted by the CMHC 4th quarter Market Outlook Report:

> *"Housing starts in British Columbia are forecast to remain relatively stable, ranging between 25,500 to 34,100 units in 2016 with a point forecast of 30,800 units. In 2017, housing starts are forecast to range between 24,300 and 35,500 units, with a point forecast of 29,900 units".*

33.1.2 Please confirm that the trends in Completed and Unabsorbed (unsold) New Homes is declining.

---

[10] Based on 6-month moving average of the monthly seasonally adjusted annual rates in June 2015.

[11] CMHC 3rd quarter market information 'Housing Now' – BC Region report is based on actual numbers till June of 2015 and does not include forecasts for 2016 and 2017.

Response:

Confirmed.

33.2 Please provide the 4th Quarter Canada Mortgage and Housing Corporation Housing Market Outlook, British Columbia Region Highlights - http://www.cmhc-schl.gc.ca/odpub/esub/65442/65442_2015_Q04.pdf.

Response:

Please refer to the response to CEC IR 1.33.1.

33.2.1 Please confirm that the point forecast is for 30,800 units in 2016.

Response:

Confirmed. Note that the point forecast of 30,800 units for 2016 appears in the 4th Quarter Report and not the 3rd Quarter report referenced in the preamble. Please refer to the response to CEC IR 1.33.1.1.

33.2.2 Please confirm that the point forecast is for 29,900 units in 2017.

Response:

Confirmed. Please refer to the response to CEC IR 1.33.1.1.

34. Reference: Exhibit B-1, Appendix C, Page 20

> In addition to the continued growth in North American natural gas supply, continued technological improvements have increased well efficiencies and reduced production costs while new industrial demand (including LNG export development) has grown more slowly. As a result, current medium and long term natural gas commodity price forecasts are lower than was predicted in 2012, as illustrated in the following Figure C-10.

34.1 Please confirm that the lower long term natural gas commodity price forecasts should serve to reduce the energy price risk relative to 2012.

Response:

The lower longer term natural gas commodity price forecasts serve to reduce the risk related to commodity prices relative to 2012, but the effect is more limited than it would have been in the past. The overall level of prices in 2012 and 2015 are at a level such that the natural gas commodity price constitutes a smaller portion of the overall delivered price of natural gas. The impact of the price change on overall business risk in and of itself is therefore muted. The risk related to commodity price volatility remains, as volatility has increased relative to 2012. As a result, on balance, FEI has characterized the overall risk related to energy prices as the same as 2012.

34.1.1 If not confirmed, please explain why not.

Response:

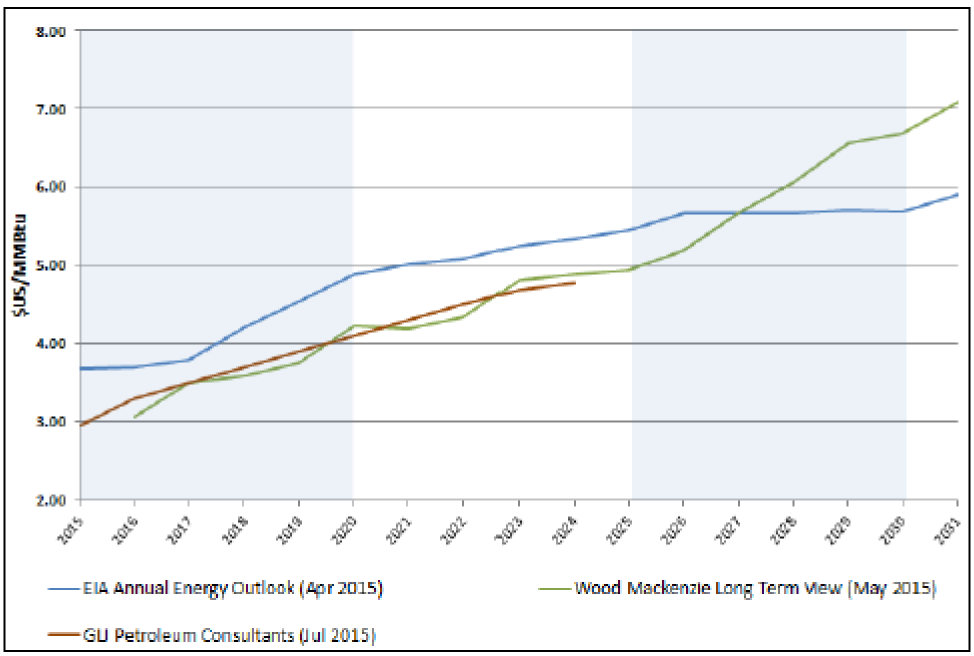
Please refer to the response to CEC IR 1.34.1.

35. Reference: Exhibit B-1, Appendix C, Page s 21 and 22

In terms of supply, the recent slowdown in the growth of gas production due to the low market price environment will also help to rebalance the market. Furthermore, with the recent drop in crude oil prices, producers are cutting back on oil production in the coming years, which will impact the associated gas that is produced with oil production. If oil and associated gas production is reduced, this could cut overall gas supply and lead to higher natural gas prices as the average cost to produce gas increases without contribution from liquids-rich associated gas. Figure C-11 below compares long-term price forecasts from different information sources for Henry Hub[23] natural gas that would reflect the expectations of the impact of long-term natural

gas supply and demand fundamentals. The long term forecasts indicated that by 2020, gas prices could be within the $4.00-$5.00 US/MMBtu range. By 2025, analysts forecast that gas prices could be within the $5.00-$5.50 US/MMBtu range.

Figure C-11: Long-Term Henry Hub Natural Gas Price Forecasts (nominal dollars)



Given the combined factors of similar natural gas current market prices and a lower medium and long term commodity price expectation, FEI assesses the natural gas commodity price risk to be slightly lower compared to 2012.

35.1 Please provide the discount factors for natural gas pricing at AECO, Station 2 and Sumas relative to Henry Hub over the last 10 years.

1 **Response:**

2 In the following table are the AECO/NIT, Station 2 and Sumas basis, or discount factors, relative
3 to the 3-day average New York Mercantile Exchange (NYMEX) settled prices for Henry Hub
4 each month.

Date	AECO Basis ($US/MMBtu)	Station 2 Basis ($US/MMBtu)	Sumas Basis ($US/MMBtu)
Nov-05	$ (3.24)	$ (3.56)	$ (2.96)
Dec-05	$ (2.25)	$ (2.58)	$ (1.87)
Jan-06	$ (1.11)	$ (2.89)	$ (1.92)
Feb-06	$ (0.94)	$ (1.83)	$ (1.24)
Mar-06	$ (0.91)	$ (1.53)	$ (0.89)
Apr-06	$ (1.49)	$ (1.82)	$ (1.36)
May-06	$ (1.44)	$ (1.77)	$ (1.45)
Jun-06	$ (0.87)	$ (1.37)	$ (1.04)
Jul-06	$ (0.78)	$ (1.26)	$ (0.90)
Aug-06	$ (1.34)	$ (1.47)	$ (0.87)
Sep-06	$ (1.26)	$ (1.63)	$ (1.27)
Oct-06	$ (0.41)	$ (0.91)	$ (0.49)
Nov-06	$ (1.51)	$ (0.99)	$ (0.15)
Dec-06	$ (1.08)	$ (0.87)	$ (0.15)
Jan-07	$ 0.07	$ (0.61)	$ 0.21
Feb-07	$ (0.84)	$ (0.65)	$ (0.02)
Mar-07	$ (0.99)	$ (1.28)	$ (0.53)
Apr-07	$ (1.03)	$ (1.24)	$ (0.84)
May-07	$ (0.85)	$ (1.23)	$ (0.86)
Jun-07	$ (0.82)	$ (1.11)	$ (0.78)
Jul-07	$ (0.80)	$ (1.32)	$ (0.89)
Aug-07	$ (0.95)	$ (1.27)	$ (0.77)
Sep-07	$ (0.69)	$ (1.09)	$ (0.66)
Oct-07	$ (1.09)	$ (1.00)	$ (0.53)
Nov-07	$ (0.76)	$ (0.57)	$ 0.23
Dec-07	$ (0.90)	$ (0.35)	$ 0.63
Jan-08	$ (0.60)	$ (0.22)	$ 0.40
Feb-08	$ (0.73)	$ (0.33)	$ 0.55
Mar-08	$ (1.30)	$ (1.12)	$ (0.65)

Date	AECO Basis ($US/MMBtu)	Station 2 Basis ($US/MMBtu)	Sumas Basis ($US/MMBtu)
Apr-08	$ (1.21)	$ (1.11)	$ (0.71)
May-08	$ (1.55)	$ (1.05)	$ (0.62)
Jun-08	$ (1.77)	$ (1.67)	$ (1.09)
Jul-08	$ (1.71)	$ (1.92)	$ (1.27)
Aug-08	$ (0.47)	$ (1.70)	$ (1.21)
Sep-08	$ (1.22)	$ (1.78)	$ (1.23)
Oct-08	$ (1.75)	$ (2.07)	$ (1.40)
Nov-08	$ (0.43)	$ (0.18)	$ 0.02
Dec-08	$ (0.74)	$ (0.47)	$ 0.10
Jan-09	$ (0.54)	$ (0.27)	$ 0.93
Feb-09	$ 0.04	$ (0.41)	$ 0.31
Mar-09	$ (0.47)	$ (0.79)	$ (0.30)
Apr-09	$ (0.78)	$ (0.88)	$ (0.38)
May-09	$ (0.41)	$ (0.77)	$ (0.55)
Jun-09	$ (0.28)	$ (0.33)	$ (0.65)
Jul-09	$ (1.00)	$ (1.09)	$ (1.16)
Aug-09	$ (0.64)	$ (0.67)	$ (0.50)
Sep-09	$ (0.43)	$ (0.68)	$ (0.42)
Oct-09	$ (1.08)	$ (0.83)	$ (0.02)
Nov-09	$ 0.10	$ 0.30	$ 0.77
Dec-09	$ 0.12	$ 0.23	$ 1.01
Jan-10	$ (0.52)	$ (0.56)	$ 0.73
Feb-10	$ (0.31)	$ (0.41)	$ 0.02
Mar-10	$ 0.08	$ (0.39)	$ (0.05)
Apr-10	$ 0.12	$ (0.22)	$ 0.08
May-10	$ (0.57)	$ (0.75)	$ (0.28)
Jun-10	$ (0.46)	$ (0.62)	$ (0.33)
Jul-10	$ (0.92)	$ (1.16)	$ (0.73)
Aug-10	$ (1.07)	$ (1.29)	$ (0.89)
Sep-10	$ (0.61)	$ (0.98)	$ (0.67)
Oct-10	$ (0.34)	$ (0.55)	$ (0.17)
Nov-10	$ 0.01	$ (0.07)	$ 0.43
Dec-10	$ (0.53)	$ (0.39)	$ 0.71
Jan-11	$ (0.27)	$ (0.60)	$ 0.04

Date	AECO Basis ($US/MMBtu)	Station 2 Basis ($US/MMBtu)	Sumas Basis ($US/MMBtu)
Feb-11	$ (0.49)	$ (0.94)	$ (0.32)
Mar-11	$ (0.21)	$ (0.59)	$ (0.03)
Apr-11	$ (0.57)	$ (0.61)	$ (0.30)
May-11	$ (0.45)	$ (0.82)	$ (0.39)
Jun-11	$ (0.38)	$ (0.50)	$ (0.32)
Jul-11	$ (0.20)	$ (0.68)	$ (0.28)
Aug-11	$ (0.58)	$ (1.04)	$ (0.42)
Sep-11	$ (0.22)	$ (0.61)	$ (0.18)
Oct-11	$ (0.29)	$ (0.68)	$ (0.09)
Nov-11	$ (0.29)	$ (0.57)	$ 0.07
Dec-11	$ (0.13)	$ (0.25)	$ 0.47
Jan-12	$ (0.11)	$ (0.11)	$ 0.37
Feb-12	$ (0.21)	$ (0.31)	$ 0.11
Mar-12	$ (0.43)	$ (0.50)	$ (0.07)
Apr-12	$ (0.39)	$ (0.44)	$ (0.25)
May-12	$ (0.35)	$ (0.48)	$ (0.21)
Jun-12	$ (0.57)	$ (0.49)	$ (0.20)
Jul-12	$ (0.77)	$ (0.63)	$ (0.31)
Aug-12	$ (0.66)	$ (0.57)	$ (0.32)
Sep-12	$ (0.43)	$ (0.58)	$ (0.19)
Oct-12	$ (0.42)	$ (0.43)	$ (0.02)
Nov-12	$ (0.14)	$ (0.10)	$ 0.52
Dec-12	$ (0.28)	$ (0.39)	$ 0.30
Jan-13	$ (0.20)	$ (0.41)	$ 0.22
Feb-13	$ (0.28)	$ (0.40)	$ 0.26
Mar-13	$ (0.38)	$ (0.49)	$ 0.08
Apr-13	$ (0.51)	$ (0.59)	$ 0.01
May-13	$ (0.51)	$ (0.70)	$ (0.25)
Jun-13	$ (0.66)	$ (0.56)	$ (0.25)
Jul-13	$ (0.62)	$ (0.78)	$ (0.24)
Aug-13	$ (0.91)	$ (0.92)	$ (0.28)
Sep-13	$ (1.18)	$ (0.98)	$ (0.35)
Oct-13	$ (0.99)	$ (0.95)	$ (0.25)
Nov-13	$ (0.24)	$ (0.23)	$ 0.68

Date	AECO Basis ($US/MMBtu)	Station 2 Basis ($US/MMBtu)	Sumas Basis ($US/MMBtu)
Dec-13	$ (0.61)	$ (0.51)	$ 0.52
Jan-14	$ (0.79)	$ (0.78)	$ 0.47
Feb-14	$ (1.12)	$ (0.97)	$ (0.03)
Mar-14	$ 0.23	$ 0.14	$ 0.65
Apr-14	$ (0.19)	$ (0.39)	$ (0.10)
May-14	$ (0.39)	$ (0.58)	$ (0.19)
Jun-14	$ (0.30)	$ (0.50)	$ (0.23)
Jul-14	$ (0.17)	$ (0.34)	$ (0.13)
Aug-14	$ (0.11)	$ (0.16)	$ (0.09)
Sep-14	$ (0.24)	$ (0.59)	$ (0.09)
Oct-14	$ (0.30)	$ (0.56)	$ (0.05)
Nov-14	$ (0.30)	$ (0.61)	$ (0.03)
Dec-14	$ (0.57)	$ (1.05)	$ 0.45
Jan-15	$ (0.26)	$ (0.97)	$ 0.10
Feb-15	$ (0.72)	$ (0.90)	$ (0.35)
Mar-15	$ (0.71)	$ (1.10)	$ (0.49)
Apr-15	$ (0.53)	$ (1.26)	$ (0.51)
May-15	$ (0.42)	$ (1.12)	$ (0.38)
Jun-15	$ (0.63)	$ (0.76)	$ (0.36)
Jul-15	$ (0.73)	$ (1.36)	$ (0.58)
Aug-15	$ (0.65)	$ (1.21)	$ (0.40)
Sep-15	$ (0.44)	$ (1.51)	$ (0.26)
Oct-15	$ (0.42)	$ (1.50)	$ (0.16)
Nov-15	$ (0.10)	$ (0.78)	$ 0.05

36. Reference: Exhibit B-1, Appendix C, Page 22

> **5.1.2 Electricity Prices**
>
> The operating costs advantage of natural gas over electricity has historically been, and continues to be, lower in BC relative to some other jurisdictions, in particular Alberta and Ontario, because of BC Hydro's low electricity prices. Although BC Hydro electricity prices are forecast to increase in the future, FEI will still be faced with the competitive challenges of maintaining and attracting customers which does not exist to the same extent in other provinces.

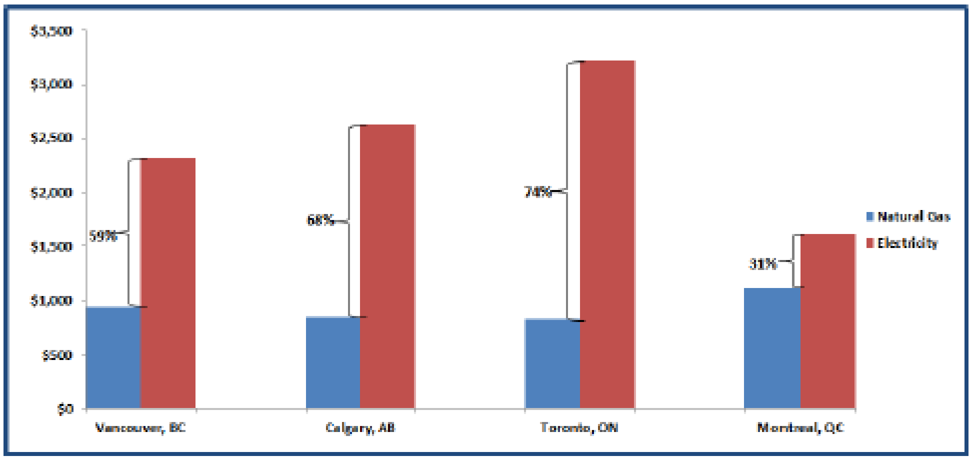
36.1 Please provide the forecast increases for BC Hydro electricity rates.

<u>Response:</u>

Please refer to the response to CEC IR 1.10.7.

37. Reference: Exhibit B-1, Appendix C, Page 23

Figure C-12: Residential Operating Cost Differences between Natural Gas and Electricity



Assumptions:

- Electricity rates are as per the Hydro-Québec *Comparison of Electricity Prices in Major North American Cities* for rates in effect April 1, 2015
- Natural gas rates are effective as at June 1, 2015 with the exception of Toronto which is effective July 1, 2015
- The efficiency of gas equipment is assumed to be 90% relative to 100% for electricity to determine equivalent electricity.
- Estimated bills are calculated based on annual use rate of 90 GJs
- All bills are exclusive of applicable franchise fees and taxes (with the exception of BC Carbon Tax)
- 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

Even with recent BC Hydro rate increases, the price of electricity is still relatively low in BC compared to major cities in Alberta and Ontario, and 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.

37.1 Please confirm that, regardless of comparators in other provinces, electricity remains significantly more costly than natural gas and the differential is expected to increase with forecast increases in BC Hydro rates.

Response:

The assessment of whether or not the differential is "significant" is subjective. FEI can confirm that electricity is more costly than natural gas on a commodity cost basis, and upfront capital costs should also be taken into consideration.[12]

As outlined in the response to CEC IR 1.10.7, BC Hydro's rates increased by approximately 9% and 6% in F2015 and F2016 respectively. The forecast rate increases for the next three years are 4%, 3.5%, and 3%.

[12] Application, Appendix C – FEI Business Risk Assessment, Section 5.3 Upfront and Installation Costs, page 38, lines 8-11.

Please refer to the response to BCUC IR 1.24.1.2 for further information.

37.1.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC 1.37.1.

38. Reference: Exhibit B-1, Appendix C, Page 24

> Natural gas prices are more volatile than electricity prices in BC principally due to the fact that natural gas is market-based, while electricity supply 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 as leading unavoidably to ever higher prices and rates in the future.[24]

38.1 Please provide the history of electricity prices in BC over the last 20 years.

Response:

Please refer to Attachment 38.1 for a history of BC Hydro residential electricity prices from 1994 to present.

39. Reference: Exhibit B-1, Appendix C, Pages 29 and 31

Regional Infrastructure

This regional market price volatility is expected to continue in the future. Regional infrastructure additions can help mitigate some of the regional price disconnection risk; however, these additions require a long time to plan, to secure shipper commitments, to receive regulatory approval, and to construct. The Southern Crossing Pipeline, Mt. Hayes LNG, and Mist and Jackson Prairie storage facilities expansions are examples of regional infrastructure projects that were approved and subsequently constructed to meet growing regional demand that helped to reduce some of the regional constraints. However, further infrastructure may be needed to meet the pace of demand growth in the PNW region if new industrial base load is added.

The potential for new regional baseload industrial load will result in greater competition for existing pipeline capacity on a year round basis. The following Figure C-19 shows a scenario of what winter 2013/14 T-South flows would look like with an additional 500 MMcf/d of gas demand compared to current pipeline capacity levels and demonstrates that new regional pipeline capacity will be required to support many of these projects.

39.1 Please confirm that FEI has the capability to identify a need, plan, secure shipper commitments, receive regulatory approval and construct infrastructure to mitigate some of the regional price disconnection risk.

<u>Response:</u>

FEI has the capability to identify a need, create a plan, and construct infrastructure once regulatory approval for the project is received. One of the main factors in receiving regulatory approval will be ensuring that the project has shipper commitments, which FEI has limited control over. This contributes to the difficulty in matching the arrival of new demand requirements with new infrastructure expansions, which can have a significant impact on regional market prices, including contributing to regional price disconnects.

39.1.1 If not confirmed, please explain why not.

<u>Response:</u>

Please refer to the response to CEC IR 1.39.1.

39.2 What plans, if any, does FEI have underway to construct infrastructure additions in the future to help mitigate some of the regional price disconnection risk? Please list with proposed construction dates.

Response:

FEI regularly assesses options for regional infrastructure solutions, whose primary purpose is to better match pipeline capacity with long-term demand. The potential projects in the region, as outlined in Mr. Coyne's evidence on page 66, will likely bring 365 days of incremental demand. Therefore, to reduce the potential regional price disconnections caused by this incremental demand coming online, pipeline infrastructure on Spectra's WestCoast pipeline system and FEI's pipeline system will likely have to expand.

The Kingsvale-Oliver Reinforcement Project (KORP) is an example of a possible future solution for the region. FEI does not have any firm shipper commitments to expand KORP; however it continues to hold discussions with regional stakeholders, including third party pipelines and industrial project proponents, to advance this potential project. These discussions include the timing of the service implementation relative to the in-service of potential industrial projects so that both are as closely matched to their needs as possible. The supply and demand fundamentals change continuously in the region, so FEI is unable to guarantee that the addition of specific pipeline infrastructure in the region will necessarily mitigate future regional price disconnects.

40. Reference: Exhibit B-1, Appendix C, Page 32

In its GCOC Stage 1 Decision, the Commission disagreed with FEI's assertion that it had fewer tools to manage price volatility and that it had expected FEI to consider alternatives for managing market price risk. During the past few years FEI has taken a number of actions in this regard which include the following:

- Research regarding customers' preferences in terms of rate and bill changes and alternative optional commodity rate offerings;
- Removing Huntingdon supply and Sumas price risk from the commodity and midstream supply portfolios;
- Entering into long-term gas supply contracts with BC producers which promote commitment to providing supply to the Station 2 market hub;
- Entering into long-term natural gas storage arrangements;
- Securing Station 2 gas supply with a fixed discount to AECO/NIT pricing;
- Independent consultant review of FEI's price risk management tools and strategies and recommendations for enhancement;
- Submission of the 2014 Price Risk Management Review Report (Review Report) which included a review of FEI's current and available price risk management strategies;
- Discussions with Commission staff regarding the Review Report and approach for stakeholder consultation; and
- Engaging stakeholders in workshop discussions to help determine FEI price risk management objectives and potential strategies going forward.

40.1 Does FEI consider the above actions to have been successful? Please explain why or why not.

Response:

FEI believes that the listed actions that relate to how it contracts for gas supply and other midstream resources have been beneficial for customers in helping to ensure long term supply reliability and security. While some of those actions have helped to reduce exposure to basis risk at Station 2 and Huntingdon, none of these actions directly mitigate the underlying market price volatility.

In addition, a number of the actions in the list refer to customer research and stakeholder consultation and discussions. These actions have been beneficial in helping FEI's stakeholder groups understand how the Company contracts for gas, the dynamics of the gas supply markets that can result in significant volatility, what tools may be available to mitigate market price volatility and how this can impact commodity rates.

41. Reference: Exhibit B-1, Appendix C, Pages 40 and 59

> Examples of requirements adopted by local governments for developers to consider alternative energy systems are addressed later in the Political Risk section of this Appendix.
>
> Since 2012, a number of regulatory exemptions have been granted to companies that provide new technology and renewable energy services. These exemptions further facilitate the development of these industries and increase their competitiveness against regulated utilities. One such an exemption is the recent Order in Council No. 23 that exempts the "*class of cases where a person, not otherwise a public utility, offers lease agreements or energy supply contracts providing lessees or buyers with solar or wind energy systems or facilities, that could otherwise be purchased on the open market, provided that the value of the installed system including equipment, labour and permits, does not exceed $500,000*"[40]. This will allow entities

> Since 2007, the BC provincial government has enacted a number of significant pieces of legislation in pursuit of its environmental and low carbon economic policies. These policies and related legislation have put substantial pressure on natural gas in its traditional role in providing heat for space and water heating, while creating some opportunities in non-traditional and less significant areas such as natural gas for transportation. The legislation includes ambitious greenhouse gas reduction targets, BC's Carbon Tax Act and the 2010 Clean Energy Act (CEA) which have focused on the role of clean and renewable energy, and energy conservation to meet the energy demands of the province, while at the same time reducing the competitiveness and ultimately the consumption of fossil fuels in BC.

41.1 Please provide a copy of British Columbia's Natural Gas Strategy, Fuelling BC's Economy for the Next Decade and Beyond, found at the website http://www.gov.bc.ca/ener/popt/down/natural_gas_strategy.pdf.

Response:

FEI agrees that the current version of the Natural Gas Strategy posted at the above link forms part of the evidence in this proceeding.

42. Reference: Exhibit B-1, Appendix C, Pages 53 and page 54

Amalgamated FEI continues to contract with third parties such as Spectra, Northwest Pipeline (NWP), and TransCanada's NOVA Gas Transmission Ltd. (NGTL) and FoothillsBC for transportation capacity in order to move supply purchased at different market supply hubs, and to complete withdrawals and injections from storage facilities, for delivery to its system. Table C-8 below provides a summary of FEI's main sources of supply as well as the related supply hubs. The FEI's main supply sources have not changed since the GCOC Stage 1 proceeding.

Table C-8: Summary of FEI's Main Sources of Gas Supply

Pipeline name	Supply Source	Main Hub	Level of importance
Spectra's Westcoast Energy Inc. (WEI)	NEBC	Station 2	Approximately 75% of FEI's gas is accessed via West Coast system. Also used for daily balancing via the Aitken Creek storage facility.
NGTL /FoothillsBC	Alberta	AECO/ NIT	Approximately 25% of FEI's gas is accessed via the NGTL and the FoothillsBC system from AECO/NIT. Also provides access to some storage capacity.
Northwest Pipeline	Washington; Oregon storage facilities	Sumas	FEI does not currently contract for Sumas supply but in the future it may provide additional security of supply during winter and peak periods if additional infrastructure is constructed.

As indicated in Table C-8, FEI remains heavily dependent on gas supply from northern BC that is transported on Spectra's WEI pipelines. There are a number of communities served by FEI in north-central BC that are entirely dependent on supply from WEI's T-South because there is no other infrastructure available for transporting natural gas to these locations. Outages or operational issues on WEI's system or in the producing regions can result in supply shortages on FEI's system.

> Due to recent regional market changes, there is a new supply risk to customers that rely on Spectra's Westcoast T-South system. New demand from projects either announced or being considered in the Lower Mainland and U.S. PNW have the capability of filling up long term T-South firm capacity.
>
> A significant volume of gas supply serving industrial customers in the Lower Mainland uses the T-South system to flow on an interruptible basis, which means their gas supply is at risk of being cut in the event there is less uncontracted transportation capacity available. Any major decrease in the future availability of transportation capacity risks leaving these customers without adequate gas supply, or they will need to pay significantly higher commodity prices at Huntingdon before any infrastructure expansions can be completed. Given that these industrial customers have not made a commitment to hold transportation capacity in the past this may present some challenges for these customers moving forward.

42.1 Please confirm that FEI has sufficient booked capacity on the pipelines to meet its supply requirements for the near term future.

Response:

Please refer to the response to BCUC Confidential IR 1.1.2.2 being filed non-confidentially.

42.2 Please provide the Supply source, main hub and level of importance for the Southern Crossing pipeline.

Response:

The Southern Crossing Pipeline (SCP) asset is a bi-directional pipeline providing the marketplace, including FEI, the flexibility to access Alberta's AECO/NIT marketplace and flow gas east to west to serve various communities in the Interior and Lower Mainland of BC. Access to the AECO/NIT marketplace is important as it allows FEI and others to diversify their portfolio by reducing reliance on the Station 2 marketplace and Spectra Energy's WestCoast Pipeline. The pipeline also provides optionality to flow gas west to east especially during the summer months when Station 2 gas can typically be sold at Kingsgate for a greater value than if resold at Huntingdon. SCP has also enabled FEI to offer T-South Enhanced Service which enables shippers the option to move gas down the Spectra T-South system and across SCP to Kingsgate. FEI customers have realized the expected benefits from the T-South Enhanced Service, including demand charge revenue from Spectra Energy and reduced tolls on T-South.

42.3 Is the Southern Crossing pipeline being utilized at capacity? Please explain.

Response:

The Southern Crossing Pipeline is a bidirectional line that connects to the interior transmission system at Oliver to serve both the South Okanagan and to transport gas to and from the interconnect with Spectra's Westcoast system at Kingsvale. The ability to deliver to or from Kingsvale is limited by the capacity of the existing 12" pipeline between Oliver and Kinsgvale. The capacity to serve the southern Okanagan is limited by both load and constraints north of Penticton.

Currently, the available capacity to serve Kingsvale is fully contracted for East to West flows from Yahk to Kingsvale by FEI and Northwest Natural (NWN), and West to East flows from Kingsvale to Yahk by Spectra's Westcoast TBO service. In addition, the remaining capacity to transport gas from Yahk to Oliver is fully utilized to meet design day conditions in the South Okanagan on a planning basis.

There are a number of moving factors including changing market conditions and shipper strategy that would determine whether the Southern Crossing Pipeline would be fully utilized throughout the year.

43. Reference: Exhibit B-1, Appendix C, Page 56

> Stage 1 Application where the benchmark utility FEI did not include the Vancouver Island and Whistler service areas, amalgamated FEI's supply interruption risks have increased somewhat for the following reasons:
>
> - Both the Vancouver Island and Whistler service areas are downstream of the Mainland Coastal Transmission System. They are dependent on a pipeline system that traverses challenging terrain.
> - Vancouver Island is supplied with three twinned submarine crossings ranging from 10.9 to 23.7 km in length. While the probability of a total failure of a submarine crossing is small, there is some additional risk associated with the difficulty of repairing a submarine crossing to maintain uninterrupted service once the gas supply that is held in the Mt. Hayes LNG facility has been depleted.
> - Whistler is served by the pipeline lateral between Squamish and Whistler, which faces single point of failure risk. Whistler also does not have any on-system storage facilities that can be used to maintain service in emergency situations. The size of the customer base in Whistler is small, limiting the potential impacts of this factor alone on FEI.

43.1 Please provide an estimate of the original supply interruption risk.

<u>Response:</u>

Please refer to the responses to BCUC IRs 1.16.1 and 1.16.2.

43.2 Please provide quantification for the size of the supply interruption risks that have increased 'somewhat' since 2012.

<u>Response:</u>

Assessment of business risk is an inherently qualitative exercise and it is not possible to quantify the size of the incremental supply interruption risk on a stand-alone basis. Instead business risk should be assessed on an overall aggregate basis. Please refer to the response to BCUC IR 1.4.2.

44. Reference: Exhibit B-1, Appendix C, Pages 67 and 68

> The City of Vancouver's recent steps to endorse and promote the Creative Energy neighbourhood energy system in Northeast False Creek (NEFC) and Chinatown with an exclusive franchise for all space and water heating, backed by a mandatory connection bylaw, demonstrates an even greater willingness on the part of local governments to dictate energy choices in relation to non-municipal utilities. The mandatory connection obligation for developers in the proposed Creative Energy franchise area and exclusivity over space and water heating for Creative Energy prevents FEI from competing for this future load in the proposed franchise area.
>
> Moreover, the City of Vancouver has indicated that the Creative Energy application is only a small part of a broader Vancouver Neighbourhood Energy Strategy. The Strategy includes conversion of the "Downtown Steam System", for "South Downtown" and for "other Expansion Areas" which includes the "West End" and "Downtown Eastside", "Cambie and Broadway Corridors". The following map prepared by the City depicts the breadth of the potentially affected areas:

> FEI estimates that the Vancouver Neighbourhood Energy Strategy which includes NEFC and Chinatown, and other areas of Downtown, Central Broadway and Cambie Corridors currently represents an annual natural gas load of 10.5 PJ, which is approximately 5% of FEI's total annual load.
>
> The framework being used with Creative Energy is applicable to new and significantly renovated buildings only, so FEI is not suggesting that the full 10.5 PJ would be immediately lost. However, at the same time, the 10.5 PJ does not include any potential for load growth in these areas. FEI does not have growth forecasts for these specific areas, or a forecast of the rate of redevelopment, so it is difficult to quantify the implications of the roll out of the Vancouver Neighbourhood Energy Strategy under a framework equivalent to that being proposed by the

44.1 Please confirm that the Neighbourhood Energy System proposed for NEFC and Chinatown will initially be reliant on natural gas to support steam heat.

<u>Response:</u>

Confirmed. Creative Energy's NEFC proposal contemplates the use of gas fired boilers until 2020 before adopting a low carbon technology. Creative Energy's first choice of low carbon technology (likely biomass) would permit switching-over the existing gas-fired steam system at the same time. The fall-back option for Creative Energy would be a low carbon technology (likely sewer heat) in NEFC.

Any temporary increase in gas throughput from the initial use of gas fired boilers is dwarfed by the potential implications of converting the existing steam system and the long-term loss of load facing FEI. The City of Vancouver's "Greenest City Action Plan" (GCAP) 2014-2015 update report indicates that plans for the expansion of district energy systems will continue with eliminating natural gas consumption as the top priority:

> *"Plans for expansion of district energy systems continue. The highest priority strategy is converting the gas-fired steam systems that serve Downtown, Vancouver General Hospital, and the BC Children's and Women's Hospital. A secondary focus is to establish new networks in areas with sufficient population density to support low-carbon systems: Downtown, Central Broadway, the Cambie Corridor and the River District neighbourhood development."*[13]

Since FEI filed this Application, the City of Vancouver has announced the *Renewable City Strategy,* which establishes two targets:

> Target 1: Derive 100% of the energy used in Vancouver from renewable sources before 2050

> Target 2: Reduce Greenhouse Gas emissions by at least 80% below 2007 levels before 2050

The "Strategic Approach" outlined is in the Strategy document is:

Strategic Approach

> 1. Reduce energy use:
>
> Advance energy conservation and efficiency programs which are the most cost-effective way to a renewable energy future.
>
> 2. Increase the use of renewable energy:
>
> Switch to renewable forms of energy that are already available to us, and make improvements to our existing infrastructure to use it to its fullest potential.
>
> 3. Increase the supply of renewable energy:
>
> Increase the supply of renewable energy and build new renewable energy infrastructure.

As forecast for 2016, customers within the CoV represent approximately 27 PJ of load on FEI's system, which amounts to approximately 13% of FEI's total forecast load for 201614. Other things being equal, if the objectives established by the CoV are achieved, such that there is no natural gas consumption within the city, this would equate to a delivery revenue loss of

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[13] http://vancouver.ca/files/cov/greenest-city-action-plan-implementation-update-2014-2015.pdf;

[14] 27 PJ divided by total load of 208 PJ as per FEI Annual Review of 2016 Rates, Exhibit B-2-1, Section 11, Schedule 19, Column 10, Line 31.

approximately $100 million which represents a delivery rate increase of approximately 13% for all remaining non-bypass sales customers[15].

The Renewable Energy Strategy Executive Summary and full Strategy are provided in Attachments 44.1. The documents can also be found at http://vancouver.ca/green-vancouver/renewable-city.aspx

44.1.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 1.44.1.

[15] $100 million divided by $767 million as per FEI Annual Review of 2016 Rates, Exhibit B-2-1, Section 11, Schedule 19, Column 5, Line 31.

45. Reference: Exhibit B-1, Appendix C, Page 70

> Although no further carbon tax changes have been announced since the current carbon tax rate took effect in mid-2012, the potential for carbon tax increases and the level of future tax remain unknown at this time. The BC government has stated that, as other jurisdictions, especially within North America, introduce similar carbon taxes or carbon pricing, it may again review and consider changes to the carbon tax. In the meantime, the competitive impacts of the carbon tax persist.

45.1 Please provide any updates FEI is aware of since the filing of this application with respect to the likelihood of a carbon tax increase in the future.

Response:

The provincial government has been in the process of developing a new Climate Leadership Plan since the spring of 2015 and is considering increases to the carbon tax in the context of that process. The provincial government has stated that it will keep the BC Carbon Tax at the current level of $30 per tonne of GHG emissions (CO_2e) until at least 2018. The recommendation in the recently-released Climate Leadership Team Report is for $10 per tonne increases each year from 2018 through 2050 in order to achieve the 2050 GHG emission reduction target. The BC government has indicated that its willingness to increase the Carbon Tax will be predicated to some extent on other jurisdictions catching up to BC in regard to carbon pricing and on mechanisms being in place to mitigate the competitive challenges faced by emissions-intensive trade-exposed sectors where competitors operate in jurisdictions with lower carbon pricing requirements. There are many groups in BC that are pushing for increases in the Carbon Tax.

In addition the Canadian federal government has recently made strong indications of its intentions to embrace strict climate change-related goals. For example, on December 6, 2015 at the COP21 meetings in Paris, the Canadian Minister of Environment and Climate Change stated Canada's support for reducing GHG emissions to a level that would limit warming of global temperatures to 1.5 degrees Celsius above pre-industrial levels (i.e., lower than the commonly noted target for warming of 2 degrees Celsius) and that countries should have legally binding GHG reduction targets. Canada, along with nearly 200 other nations, was a signatory to agreement reached at the COP21 meetings, further confirming Canada's intentions to pursue carbon emission reductions and climate change mitigation initiatives. Only time will tell how these matters will develop and how they will affect Canada and BC, but it is safe to say that they are moving in the direction of stricter carbon emission policies and higher carbon prices.

In light of the uncertainty around the future changes to carbon pricing, FEI's position and evidence in this proceeding is not premised on the basis of the adoption of the recommendations of the Climate Leadership Team. The future adoption of these factors would represent a further increase in the level of political risk, and increases in the carbon tax would impact the price competitiveness of natural gas.

Attachment 1.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 1.4.1

Canada Long-Horizon Equity Risk Premia

Long-Horizon Equity Risk Premia in Local Currency (Canadian Dollar – CAD) in Percent

End Date \ Start Date	1919	1920	1925	1930	1935	1940	1945	1950	1955	1960	1965	1970	1975	1980	1985	1990	1995	2000	2005	2010	2014
1958	7.8	7.8	8.7	7.2	9.9	10.7	13.5	14.8	9.2												
1959	7.6	7.6	8.5	7.0	9.5	10.2	12.6	13.3	7.3												
1960	7.4	7.4	8.1	6.6	9.0	9.5	11.6	11.8	5.5	-3.5											
1961	7.9	7.9	8.6	7.3	9.7	10.3	12.5	13.1	8.7	12.0											
1962	7.4	7.4	8.1	6.7	8.9	9.4	11.2	11.2	6.1	4.0											
1963	7.5	7.5	8.2	6.8	8.9	9.4	11.1	11.1	6.6	5.6											
1964	7.7	7.7	8.5	7.2	9.3	9.8	11.6	11.7	7.9	8.5											
1965	7.6	7.6	8.3	7.0	9.1	9.5	11.1	11.1	7.3	7.4	1.6										
1966	7.2	7.2	7.8	6.5	8.4	8.7	10.0	9.7	5.7	4.5	-5.5										
1967	7.3	7.3	7.9	6.7	8.5	8.8	10.1	9.8	6.2	5.5	0.4										
1968	7.5	7.5	8.1	6.9	8.7	9.1	10.4	10.2	6.9	6.6	4.3										
1969	7.2	7.1	7.7	6.5	8.2	8.5	9.6	9.2	5.9	5.2	1.8										
1970	7.0	7.0	7.6	6.4	8.0	8.2	9.3	8.8	5.5	4.7	1.5	0.1									
1971	7.0	7.0	7.5	6.3	8.0	8.2	9.1	8.7	5.5	4.8	2.1	3.0									
1972	7.4	7.3	7.9	6.8	8.4	8.7	9.7	9.4	6.7	6.4	5.1	10.6									
1973	7.0	7.0	7.5	6.4	8.0	8.1	9.0	8.6	5.8	5.2	3.4	5.4									
1974	6.3	6.2	6.7	5.5	6.9	6.9	7.6	6.8	3.7	2.5	-0.5	-2.7									
1975	6.3	6.3	6.7	5.6	6.9	7.0	7.6	6.9	4.0	3.0	0.4	-0.7	9.4								
1976	6.2	6.2	6.6	5.4	6.8	6.8	7.4	6.7	3.8	2.8	0.4	-0.6	4.6								
1977	6.1	6.0	6.4	5.3	6.6	6.5	7.1	6.4	3.5	2.5	0.2	-0.9	2.3								
1978	6.3	6.3	6.7	5.6	6.9	6.9	7.5	6.9	4.3	3.5	1.7	1.7	7.1								
1979	6.9	6.9	7.3	6.3	7.6	7.8	8.5	8.0	5.8	5.4	4.3	5.6	13.9								
1980	7.0	7.0	7.4	6.4	7.8	7.9	8.6	8.2	6.0	5.7	4.8	6.2	13.6	12.4							
1981	6.5	6.5	6.9	5.9	7.1	7.1	7.7	7.2	4.9	4.4	3.1	3.7	8.3	-5.7							
1982	6.3	6.2	6.6	5.6	6.8	6.8	7.3	6.7	4.4	3.8	2.5	2.7	6.2	-6.7							
1983	6.5	6.5	6.9	5.9	7.1	7.1	7.6	7.1	5.0	4.6	3.5	4.1	7.9	0.5							
1984	6.2	6.2	6.5	5.5	6.7	6.6	7.1	6.5	4.4	3.8	2.7	2.9	5.8	-2.3							
1985	6.3	6.3	6.6	5.6	6.7	6.8	7.2	6.7	4.6	4.1	3.1	3.5	6.3	0.0	11.5						
1986	6.2	6.2	6.5	5.5	6.6	6.6	7.0	6.5	4.5	4.0	2.9	3.2	5.7	-0.1	5.5						
1987	6.1	6.0	6.4	5.4	6.5	6.4	6.8	6.3	4.3	3.8	2.7	3.0	5.2	-0.2	3.2						
1988	6.0	5.9	6.2	5.3	6.3	6.3	6.6	6.1	4.1	3.6	2.5	2.7	4.7	-0.4	1.9						
1989	6.0	6.0	6.3	5.4	6.4	6.4	6.7	6.2	4.3	3.8	2.9	3.2	5.1	0.7	3.8						
1990	5.6	5.6	5.9	4.9	5.9	5.8	6.1	5.5	3.6	3.0	1.9	2.0	3.4	-1.3	-0.5	-22.1					
1991	5.6	5.6	5.8	4.9	5.8	5.7	6.0	5.4	3.5	2.9	1.9	1.9	3.3	-1.1	-0.3	-10.4					
1992	5.4	5.3	5.6	4.6	5.5	5.4	5.7	5.0	3.1	2.5	1.4	1.3	2.5	-1.9	-1.7	-10.8					
1993	5.5	5.5	5.7	4.8	5.7	5.6	5.8	5.2	3.4	2.9	1.9	1.9	3.1	-0.7	0.2	-4.3					
1994	5.4	5.3	5.6	4.6	5.5	5.4	5.6	5.0	3.2	2.7	1.7	1.7	2.8	-0.9	-0.3	-4.3					
1995	5.4	5.3	5.6	4.7	5.5	5.4	5.7	5.1	3.3	2.8	1.9	1.9	3.0	-0.4	0.4	-2.4	6.9				
1996	5.6	5.6	5.8	4.9	5.8	5.7	6.0	5.4	3.8	3.3	2.5	2.6	3.9	0.9	2.2	1.1	14.7				

Source of underlying data: 1.) Morningstar *Direct* database. Used with permission. All calculations performed by Duff & Phelps LLC.

Attachment 11.1

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

FORTIS INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2008

March 13, 2009

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2008

TABLE OF CONTENTS

DEFINITIONS OF CERTAIN TERMS

Certain terms used in the Annual Information Form for the year ended December 31, 2008 are defined below:

"2008 Annual Information Form" means the Fortis Inc. Annual Information Form for the year ended December 31, 2008;

"Abitibi-Consolidated" means Abitibi-Consolidated Company of Canada;

"Advisory Panel" means the Advisory Panel on Canada's System of International Taxation;

"AIP" means agreement in principle;

"AUC" means Alberta Utilities Commission;

"BC Hydro" means BC Hydro and Power Authority;

"BCUC" means British Columbia Utilities Commission;

"BECOL" means Belize Electric Company Limited;

"Belize Electricity" means Belize Electricity Limited;

"BEPC" means Brilliant Expansion Power Corporation;

"BEWU" means Belize Energy Workers Union;

"Board" means Board of Directors of Fortis Inc.;

"BPC" means Brilliant Power Corporation;

"BZ" means Belizean currency, which is pegged to the United States currency (BZ$2.00 = US$1.00);

"Canadian GAAP" means Canadian generally accepted accounting principles;

"Canadian Niagara Power" means Canadian Niagara Power Inc.;

"Caribbean Utilities" means Caribbean Utilities Company, Ltd.;

"CAW" means Canadian Auto Workers-Retail/Wholesale;

"CEP" means Communications, Energy and Paperworkers Union of Canada;

"CFE" means Comisión Federal de Electricidad;

"CIP" means capital investment plan;

"COPE" means Canadian Office & Professional Employees Union;

"Cornwall Electric" means Cornwall Street Railway, Light and Power Company, Limited;

“Corporation” means Fortis Inc.;

“COS” means cost of service;

“CPC/CBT” means Columbia Power Corporation and the Columbia Basin Trust;

“CPA” means Canal Plant Agreement;

“CPRSA” means Cost of Power Rate Stabilization Account;

“CRA” means Canada Revenue Agency;

“CPI” means consumer price index;

“CRS” means Cost-Recovery Surcharge;

“CUPE” means Canadian Union of Public Employees;

“DBRS” means DBRS Limited;

“ECAM” means energy cost adjustment mechanism;

“ERA” means Electricity Regulatory Authority;

“Exploits Partnership” means Exploits River Hydro Partnership between Abitibi-Consolidated and Fortis Properties;

“External Auditor” means the firm of chartered accountants registered with the Canadian Public Accountability Board or its successor and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

“FEBL” means Fortis Energy (Bermuda) Limited;

“FERC” means United States Federal Energy Regulatory Commission;

“First Preference Share, Series G” means Cumulative Redeemable Five-Year Fixed-Rate Reset First Preference Shares, Series G;

“Fortis” means Fortis Inc.;

“FortisAlberta” means FortisAlberta Inc.;

“FortisAlberta Holdings” means FortisAlberta Holdings Inc.;

“FortisBC” means, collectively, the operations of FortisBC Inc. and its parent company, Fortis Pacific Holdings Inc., but excluding its wholly owned partnership, Walden Power Partnership;

“FortisBC Inc.” means FortisBC Inc.;

“FortisOntario” means, collectively, the operations of Canadian Niagara Power and Cornwall Electric. Included in Canadian Niagara Power’s accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc.;

“FortisOntario Inc.” means the successor to Canadian Niagara Power Company, Limited and the parent company of Canadian Niagara Power and Cornwall Electric;

“Fortis Pacific Holdings” means Fortis Pacific Holdings Inc.;

“Fortis Properties” means Fortis Properties Corporation;

“Fortis Turks and Caicos” means, collectively, P.P.C. Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd.;

“FortisUS Energy” means FortisUS Energy Corporation;

“FortisWest” means FortisWest Inc.;

“GWh” means gigawatt hour(s);

“Hydro One” means Hydro One Networks Inc.;

“IBEW” means International Brotherhood of Electrical Workers;

“IESO” means Independent Electricity System Operator of Ontario;

“IFRS” means International Financial Reporting Standards;

“IRAC” means Island Regulatory and Appeals Commission;

“IRM” means Incentive Regulation Mechanism;

“ISO” means International Organization for Standardization;

“kWh” means kilowatt hour(s);

“MD&A” means the Corporation’s Management Discussion and Analysis, located on pages 20 through 79 of the Corporation’s 2008 Annual Report to Shareholders, prepared in accordance with National Instrument 51-102 – Continuous Disclosure Obligations, in respect of the Corporation’s annual and interim financial statements;

“Management” means, collectively, senior officers of the Corporation;

“Maritime Electric” means Maritime Electric Company, Limited;

“Moody’s” means Moody’s Investors Service;

“MW” means megawatt(s);

“NB Power” means New Brunswick Power Corporation;

“Newfoundland Hydro” means Newfoundland and Labrador Hydro Corporation;

“Newfoundland Power” means Newfoundland Power Inc.;

“NSA” means Negotiated Settlement Agreement;

“OEB” means Ontario Energy Board;

“Other Canadian Electric Utilities” means, collectively, the operations of FortisOntario and Maritime Electric;

“PBR” means performance-based rate-setting methodology for regulation of public utilities;

“PIF” means productivity improvement factor;

“PJ” means petajoule(s);

“Point Lepreau Station” means NB Power Point Lepreau Nuclear Generating Station;

“Port Colborne Hydro” means Port Colborne Hydro Inc.;

“PUB” means Newfoundland and Labrador Board of Commissioners of Public Utilities;

“PUC” means Public Utilities Commission (Belize);

“ROA” means regulated rate of return on rate base assets;

“ROE” means rate of return on common shareholders’ equity;

“S&P” means Standard & Poor’s;

“Teck Cominco” means Teck Cominco Metals Ltd.;

“Terasen Gas companies” means, collectively, the operations of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.;

“Terasen” means Terasen Inc., the holding company of the Terasen Gas companies;

“TGI” means Terasen Gas Inc.;

“TGVI” means Terasen Gas (Vancouver Island) Inc.;

“TGWI” means Terasen Gas (Whistler) Inc.;

“TIEA” means tax information-exchange agreements;

“TJ” means terajoule(s);

“UFCW” means United Food and Commercial Workers;

“USW” means United Steel Workers;

“UUWA” means United Utility Workers Association;

“VAD” means value-added delivery;

“Village” means the Village of Philadelphia, New York;

“VINGPA” means Vancouver Island Natural Gas Pipeline Agreement; and

“Walden” means Walden Power Partnership.

1.0 CORPORATE STRUCTURE

The 2008 Annual Information Form has been prepared in accordance with National Instrument 52-102 – *Continuous Disclosure Obligations*. Financial information has been prepared in accordance with Canadian GAAP and is presented in Canadian dollars unless otherwise specified.

Except as otherwise stated, the information in the 2008 Annual Information Form is given as of December 31, 2008.

Fortis includes forward-looking information in the 2008 Annual Information Form within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide Management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. 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 2008 Annual Information Form includes, but is not limited to, statements regarding: the expected timing of regulatory decisions; the electricity sales growth rate expected at the Corporation's regulated utilities in the Caribbean in 2009; consolidated forecasted gross capital expenditures for 2009 and in total over the next five years, as well as the expected significant capital projects in 2009 and their expected costs and time to complete; the expected impacts on Fortis of the downturn in the global economy; the expected increase in activities at Terasen Energy Services; no significant decrease in subsidiary operating cash flows is expected in 2009; the subsidiaries expect to be able to source the cash required to fund their 2009 capital expenditure programs; the Corporation and its subsidiaries expect to continue to have reasonable access to long-term capital in 2009; expected long-term debt maturities and repayments in 2009 and on average annually over the next five years; no material increase in interest expense and/or fees associated with renewed and extended credit facilities is expected in 2009; no material adverse credit rating actions are expected in the near term; the expected impact of a change in the US dollar-to-Canadian dollar foreign exchange rate on basic earnings per common share in 2009; the estimated impact a decease in revenue at Fortis Properties' Hospitality Division would have on basic earnings per common share; the expectation that counterparties to the Terasen Gas companies' gas derivative contracts will continue to meet their obligations; and the expectation of no material increase in defined benefit pension expense in 2009. The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major event; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no significant decline in capital spending in 2009; no severe and prolonged downturn in economic conditions; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the continued ability to hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas commodity prices; no significant variability in interest rates; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas supply; the continued ability to fund defined benefit pension plans; the absence of significant changes in government energy plans and environmental laws that may materially affect the operations and cash flows of the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; no material decrease in market energy sales prices; favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program. 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. Factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory risk; operating and maintenance risks; economic conditions; capital resources and liquidity risk; weather and seasonality; an ultimate resolution of the Exploits Partnership that differs from what is currently expected by Management; commodity price risk; derivative financial instruments and hedging; interest rate risk; counterparty risk; competitiveness of natural gas; natural gas supply; defined benefit pension plan performance and funding requirements; risks related to the development of the TGVI franchise; the Government of British Columbia's Energy Plan; environmental risks; insurance coverage risk; an unexpected outcome of legal proceedings currently against the Corporation; licences and permits; loss of service area; market *energy sales prices; transition to IFRS; changes in tax legislation; First Nations' lands; labour relations and human resources. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Risk Factors" in the 2008 Annual Information Form.*

All forward-looking information in the 2008 Annual Information Form is qualified in its entirety by the above cautionary statements 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.

1.1 Name and Incorporation

Fortis is a holding company that was incorporated as 81800 Canada Ltd. under the *Canada Business Corporations Act* on June 28, 1977 and continued under the *Corporations Act* (Newfoundland and Labrador) on August 28, 1987.

The articles of incorporation of the Corporation were amended to: (a) change its name to Fortis Inc. on October 13, 1987; (b) set out the rights, privileges, restrictions and conditions attached to the Common Shares on October 15, 1987; (c) designate 2,000,000 First Preference Shares, Series A on September 11, 1990; (d) replace the class rights, privileges, restrictions and conditions attaching to the First Preference Shares and the Second Preference Shares on July 22, 1991; (e) designate 2,000,000 First Preference Shares, Series B on December 13, 1995; (f) designate 5,000,000 First Preference Shares, Series C on May 27, 2003; (g) designate 8,000,000 First Preference Shares, Series D and First Preference Shares, Series E on January 23, 2004; (h) amend the redemption provisions attaching to the First Preference Shares, Series D on July 15, 2005; (i) designate 5,000,000 First Preference Shares, Series F on September 22, 2006; and (j) designate 9,200,000 First Preference Shares, Series G on May 20, 2008.

Fortis redeemed all of its outstanding First Preference Shares, Series A and First Preference Shares, Series B on September 30, 1997 and December 2, 2002, respectively. On June 3, 2003, Fortis issued 5,000,000 First Preference Shares, Series C. On January 29, 2004, Fortis issued 8,000,000 First Preference Units, each unit consisting of one First Preference Share, Series D and one Warrant. During 2004, 7,993,500 First Preference Units were converted into 7,993,500 First Preference Shares, Series E and 6,500 First Preference Shares, Series D remained outstanding. On September 20, 2005, the 6,500 First Preference Shares, Series D were redeemed by the Corporation. On September 28, 2006, Fortis issued 5,000,000 First Preference Shares, Series F. On May 23, 2008, Fortis issued 8,000,000 First Preference Shares, Series G and on June 4, 2008 issued an additional 1,200,000 First Preference Shares, Series G, following the exercise of an over-allotment option in connection with the offering of the 8,000,000 First Preference Shares, Series G.

The corporate head and registered office of Fortis is located at the Fortis Building, Suite 1201, 139 Water Street, P.O. Box 8837, St. John's, NL, Canada, A1B 3T2.

1.2 Inter-Corporate Relationships

Fortis is principally an international distribution utility holding company. Its regulated holdings include electric distribution utilities in five Canadian provinces and three Caribbean countries and a natural gas utility in British Columbia. As at December 31, 2008, regulated utility assets comprised approximately 92 per cent of the Corporation's total assets, with the balance primarily comprised of non-regulated generation assets, mainly hydroelectric, across Canada and in Belize and Upper New York State, and hotels and commercial real estate in Canada.

The following table lists the principal subsidiaries of the Corporation, their jurisdictions of incorporation and the percentage of votes attaching to voting securities held directly or indirectly by the Corporation as at March 13, 2009. This table excludes certain subsidiaries, the total assets of which individually constituted less than 10 per cent of the Corporation's consolidated assets as at December 31, 2008, or the total revenues of which individually constituted less than 10 per cent of the Corporation's 2008 consolidated revenues. Additionally, the principal subsidiaries together comprise 82 per cent of the Corporation's consolidated assets as at December 31, 2008 and 82 per cent of the Corporation's 2008 consolidated revenue.

Principal Subsidiaries		
Subsidiary	**Jurisdiction of Incorporation**	**Percentage of votes attaching to voting securities beneficially owned, controlled or directed by the Corporation**
Terasen	British Columbia	100
FortisAlberta (1)	Alberta	100
FortisBC Inc. (2)	British Columbia	100
Newfoundland Power	Newfoundland and Labrador	93.7 (3)
Caribbean Utilities	Cayman Islands	57 (4)

(1) FortisAlberta Holdings, an Alberta corporation, owns all of the shares of FortisAlberta. FortisWest, a Canadian corporation, owns all of the shares of FortisAlberta Holdings. Fortis owns all of the shares of FortisWest.

(2) Fortis Pacific Holdings, a British Columbia corporation, owns all of the shares of FortisBC Inc. FortisWest, a Canadian corporation, owns all of the shares of Fortis Pacific Holdings. Fortis owns all of the shares of FortisWest.

(3) Fortis owns all of the common shares; 182,300 First Preference Shares, Series G; 33,181 First Preference Shares, Series B; 13,000 First Preference Shares, Series D and 1,713 First Preference Shares, Series A of Newfoundland Power which, at March 13, 2009, represented 93.7 per cent of its voting securities. The remaining 6.3 per cent of Newfoundland Power's voting securities consist of First Preference Shares, Series A, B, D and G which are primarily held by the public.

(4) FEBL owns 15,989,329 of the Class A Ordinary Shares of Caribbean Utilities which, at March 13, 2009, represented approximately 57 per cent of its voting securities. The remaining 43 per cent of Caribbean Utilities' voting securities consist of Class A Ordinary Shares which are primarily held by the public. Fortis owns all of the shares of FEBL.

2.0 GENERAL DEVELOPMENT OF THE BUSINESS

2.1 Three-Year History

Over the past three years, the business operations of Fortis have increased significantly. Total assets have grown more than 2.4 times from $4.6 billion as at December 31, 2005 to $11.2 billion as at December 31, 2008. The Corporation's shareholders' equity has also grown 2.8 times from $1.2 billion as at December 31, 2005 to $3.4 billion as at December 31, 2008. Over the past three years, net earnings applicable to common shares have increased from $137 million in 2005 to $245 million in 2008.

The significant growth reflects the Corporation's profitable growth strategy for its principal businesses of regulated gas and electricity distribution. This strategy includes a combination of growth through acquisitions and organic growth through the Corporation's consolidated capital expenditure program.

The significant growth over the past three years primarily reflected the approximate $3.7 billion acquisition of Terasen in May 2007. The addition of Terasen's gas distribution business doubled the Corporation's investment in regulated rate base assets and marked the Corporation's expansion into natural gas distribution. In addition, Fortis has increased its regulated utility investments in the Caribbean through the acquisition of Fortis Turks and Caicos and the acquisition of a controlling interest in Caribbean Utilities, both of which occurred in 2006. The Corporation has increased its non-regulated investments over the last three years through the acquisition of six hotels in Canada.

Organic growth has been driven by the capital expenditure programs at FortisAlberta and FortisBC. Total assets at FortisAlberta and FortisBC have grown by approximately 50 per cent and 28 per cent, respectively, over the past three years.

2.2 Outlook

The Corporation maintains a profitable growth strategy for its principal businesses of regulated gas and electricity distribution. This strategy includes a combination of growth through acquisitions and organic growth through the Corporation's consolidated capital expenditure program.

The Corporation's principal businesses of regulated gas and electricity distribution are capital intensive. Over the next five years, the Corporation's consolidated gross capital expenditures are expected to total approximately $4.5 billion. Approximately $3.1 billion of the capital spending is expected be incurred at the regulated electric utilities, driven by FortisAlberta, FortisBC and regulated utility operations in the Caribbean. Approximately $1.2 billion is expected to be incurred at the regulated gas utilities. Capital expenditures at the regulated utilities are subject to regulatory approval. Non-regulated capital expenditures are expected to total approximately $200 million over the same period.

Consolidated gross capital expenditures for 2009 are expected to be approximately $1 billion, as summarized in the following table.

Fortis Forecast Gross Capital Expenditures Year Ending December 31, 2009	
	($ millions)
Terasen Gas Companies	287
FortisAlberta	292
FortisBC	142
Newfoundland Power	65
Other Canadian Electric Utilities	34
Regulated Electric Utilities – Caribbean	118
Non-Regulated Utility	56
Fortis Properties	33
Total	**1,027**

With its substantial credit facilities and conservative capital structure, Fortis believes it has the financial flexibility to respond to the global economic downturn and volatility in the capital markets anticipated to continue in 2009. The Corporation and its utilities also expect to continue to have reasonable access to long-term capital in 2009.

The Corporation's capital program should drive growth in earnings and dividends. The Corporation continues to pursue acquisitions for profitable growth, focusing on opportunities to acquire regulated natural gas and electric utilities in Canada, the United States and the Caribbean. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

3.0 DESCRIPTION OF THE BUSINESS

Fortis is principally an international distribution utility holding company. Its core business is highly regulated and is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation, and commercial real estate and hotels, which are treated as two separate segments. The Corporation's reporting segments allow Management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. Each reporting segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The operating segments of the Corporation are: (i) Regulated Gas Utilities - Canadian, (ii) Regulated Electric Utilities - Canadian, (iii) Regulated Electric Utilities - Caribbean, (iv) Non-Regulated - Fortis Generation; (v) Non-Regulated - Fortis Properties, and (vi) Corporate and Other.

The following sections describe the operations in each of the Corporation's reportable segments.

3.1 Regulated Gas Utilities - Canadian

3.1.1 *Terasen Gas Companies*

The Regulated Gas Utilities - Canadian segment comprises the gas distribution business of TGI, TGVI and TGWI, collectively referred to as the Terasen Gas companies, which Fortis acquired through the acquisition of Terasen on May 17, 2007.

TGI is the largest distributor of natural gas in British Columbia, serving approximately 834,000 residential, commercial and industrial customers in a service area that extends from Vancouver to the Fraser Valley and the interior of British Columbia.

TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast of British Columbia, serving approximately 95,000 residential, commercial and industrial customers.

In addition to providing transmission and distribution services to customers, TGI and TGVI also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through TGI's Southern Crossing Pipeline, from Alberta.

TGWI owns and operates the propane distribution system in Whistler, British Columbia, providing service to approximately 2,400 residential and commercial customers.

The Terasen Gas companies own and operate more than 46,000 kilometers of natural gas distribution and transmission pipelines and met a peak day demand of 1,402 TJ in 2008.

Market and Sales

The Terasen Gas companies' annual customer gas volumes increased to 221,122 TJ in 2008 from 220,977 TJ in 2007. Revenue was $1.90 billion in 2008 compared to $1.75 billion in 2007. Financial results for the Terasen Gas companies are included in the consolidated financial statements of the Corporation from the date of acquisition, May 17, 2007. The Terasen Gas companies' gas volumes and revenue from the date of acquisition to December 31, 2007 were 118,309 TJ and $905 million, respectively.

The following table compares the composition of 2008 and 2007 gas rate revenue and gas volumes by customer class of the Terasen Gas companies.

Terasen Gas Companies Gas Rate Revenue and Gas Volumes by Customer Class				
	Revenue *(per cent)*		**PJ Volumes** *(per cent)*	
	2008	2007 [(1)]	**2008**	2007 [(1)]
Residential	**57.7**	57.1	**35.5**	33.9
Commercial	**33.1**	32.9	**19.9**	19.1
Small industrial	**1.7**	1.9	**1.4**	1.6
Large industrial and other	**0.1**	0.1	**0.1**	0.1
Total natural gas sales	**92.6**	92.0	**56.9**	54.7
Transportation and other	**7.4**	8.0	**43.1**	45.3
Total	**100.0**	100.0	**100.0**	100.0

[(1)] *The 2007 figures are for the year ended December 31, 2007. The Corporation acquired the Terasen Gas companies on May 17, 2007; therefore, only revenue since May 17, 2007 is reflected in the consolidated financial statements of the Corporation.*

Gas Purchase Agreements

In order to acquire supply resources that ensure reliable natural gas deliveries to its customers, the Terasen Gas companies purchase supply from a select list of producers, aggregators and marketers by adhering to strict standards of counterparty creditworthiness and contract execution/management procedures. TGI contracts for approximately 113 PJ of baseload and seasonal supply, of which 81 PJ is delivered off the Spectra Energy Gas transmission system and 14 PJ is comprised primarily of Alberta-sourced supply transported into British Columbia via TransCanada Pipelines Limited's Alberta and British Columbia systems. The remaining 18 PJ of baseload and seasonal supply is sourced at Sumas, British Columbia. TGVI contracts for approximately 11 PJ of annual supply comprised of base load and seasonal contracts of which approximately 9 PJ is delivered off the Spectra Energy Gas transmission system and 2 PJ sourced directly at Sumas.

Through the operation of regulatory deferrals, any difference between the forecasted cost of natural gas purchases, as reflected in customer rates, and the actual cost of natural gas purchases is recovered from, or refunded to, customers in future rates. The majority of supply contracts in the current portfolio are seasonal for either the summer period (April to October) or winter period (November to March) with a few contracts one year or longer in length.

The Spectra Energy Gas transmission and TransCanada Pipeline Limited transportation tolls are regulated by the National Energy Board, whose responsibilities include regulating pipeline tolls. The Terasen Gas companies pay both fixed and variable charges for use of the pipelines, which are recovered through rates paid by its customers.

Peak Shaving Arrangements

TGI and TGVI incorporate peak shaving and gas storage facilities into its portfolio to:

i. manage the load factor of baseload supply contracts throughout the year;
ii. eliminate the risk of supply shortages during a peak throughput day;
iii. reduce the cost of gas during winter months; and
iv. balance daily supply and demand on the distribution system.

The Terasen Gas companies' peak shaving and storage assets and contracts for 2009 include up to 30 PJ in storage capacity at various locations throughout British Columbia, Alberta and the Pacific Northwest of the United States. These facilities can deliver a maximum daily rate of 574 TJ on a combined basis.

TGVI maintains storage contracts with Unocal Canada Limited at the Aitken Creek Storage facility in Northern British Columbia and Northwest Natural Gas Company at the Mist Storage facility in Oregon, United States. TGVI's Aitken Creek storage contract consists of 2 PJ of capacity with 14 TJ of daily deliverability and its Mist storage contract consists of 0.69 PJ of capacity with 26 TJ of daily deliverability. TGVI also has access to an estimated 26 TJ of daily peak supply deliverability from various peak supply arrangements.

Off-System Sales

TGI is in its 13th year of off-system sales activities, in which any daily excess supply of gas is sold at the market spot rate and allows for the recovery or mitigation of costs on unutilized supply and/or pipeline capacity. In 2007/2008, TGI marketed approximately 23.5 PJ of surplus gas and 43.7 PJ of excess pipeline capacity for a net pre-tax recovery of approximately $181.5 million. Through the Gas Supply Mitigation Incentive Plan established with the BCUC, $1.1 million (pre-tax) of these benefits accrued to shareholders with the remainder flowing through to customers in the form of reduced natural gas costs.

Unbundling

Over the past several years, TGI, the BCUC and other interested parties have laid the groundwork for the introduction of natural gas commodity unbundling in British Columbia. On November 1, 2004, commercial customers of TGI became eligible to buy their natural gas commodity supply from third-party suppliers. TGI continues to provide delivery of the natural gas. Approximately 80,000 commercial customers are eligible to participate in commodity unbundling. By December 31, 2008, approximately 19,800 customers had elected to participate in this program.

During 2006, the BCUC approved the offering of commodity supply choice to residential customers. The BCUC agreed to open a portion of the Province of British Columbia's residential natural gas market to competition, allowing homeowners to sign long-term fixed-price contracts for natural gas with companies other than TGI, effective May 2007. Consumers had the option to remain with TGI or sign with another market participant, in which case they began receiving gas at that market participant's rate beginning in November 2007. TGI continues to provide delivery service to unbundled customers and delivery margins are not expected to be impacted by migration of residential customers to alternative commodity suppliers. Approximately 748,000 residential customers are eligible to participate in commodity unbundling. By December 31, 2008, approximately 115,500 customers had elected to participate in this program. Neither residential nor commercial unbundling has had a material effect on the delivery margins of TGI.

Legal Proceedings

On March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform (the "Minister") in British Columbia issued a decision in respect of the appeal by TGI of an assessment of additional British Columbia Social Service Tax in the amount of approximately $37 million associated with the Southern Crossing Pipeline, which was completed in 2000. The Minister reduced the assessment to $7 million, including interest, which has been paid in full to avoid accruing further interest and recorded as a long-term regulatory deferral asset. The matter is currently under appeal to the Supreme Court of British Columbia.

During 2007 and 2008, a non-regulated subsidiary of Terasen received Notices of Assessment from CRA for additional taxes related to the taxations years 1999 through 2003. The exposure has been fully provided for in the Corporation's 2008 consolidated financial statements. Terasen has begun the appeal process associated with the assessments.

In 2008, the Vancouver Island Gas Joint Venture commenced a claim against TGVI seeking damages for alleged past overpayments and a future reduction in their tolls. The Statement of Claim does not quantify damages and, as such, the Company cannot determine the amount of the claim at this time. It is the Company's view that the claim is without merit. No amount, therefore, has been accrued in the Corporation's 2008 consolidated financial statements.

Human Resources

At December 31, 2008, the Terasen Gas companies employed 1,260 full-time equivalent employees. Approximately 75 per cent of the employees are represented by IBEW, Local 213 and COPE, Local 378 under collective agreements that expire on March 31, 2011 and March 31, 2012, respectively.

3.2 Regulated Electric Utilities - Canadian

3.2.1 *FortisAlberta*

FortisAlberta is a regulated electric distribution utility in the Province of Alberta. Its business is the ownership and operation of regulated electric distribution facilities that distribute electricity generated by other market participants from high-voltage transmission substations to end-use customers. FortisAlberta is not involved in the generation, transmission or direct sale of electricity. FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, totalling approximately 108,000 kilometres of distribution lines. The Company's distribution network serves approximately 461,000 customers, comprising residential, commercial, farm and industrial consumers of electricity, and met a peak demand of 3,150 MW in 2008.

Market and Sales

FortisAlberta's annual energy deliveries increased to 15,722 GWh in 2008 from 15,378 GWh in 2007. Revenue was $300 million in 2008 compared to $270 million in 2007.

The following table compares the composition of FortisAlberta's 2008 and 2007 electric rate revenue and energy deliveries by customer class.

FortisAlberta Electric Rate Revenue and Energy Deliveries by Customer Class				
	Revenue *(per cent)*		**GWh Deliveries** [(1)] *(per cent)*	
	2008	2007	**2008**	2007
Residential	**30.5**	30.8	**16.4**	16.2
Large commercial and industrial [(2)]	**22.6**	22.4	**60.9**	60.8
Farms	**12.9**	13.3	**8.2**	8.5
Small commercial	**11.6**	12.0	**8.0**	8.1
Small oil and gas	**9.6**	9.8	**6.0**	6.0
Other [(3)]	**12.8**	11.7	**0.5**	0.4
Total	**100.0**	100.0	**100.0**	100.0

(1) GWh percentages presented exclude FortisAlberta's GWh deliveries to "transmission-connected" customers. These deliveries consist primarily of large-scale industrial customers directly connected to the transmission grid. The Company collects energy delivery information and discloses it as the volume risk on transmission throughput that resides with the distribution utility. This transmission revenue is recorded net of expenses in other revenue in FortisAlberta's financial statements.

(2) Included in the large commercial and industrial customer class are large oil and gas customers

(3) Includes revenue from sources other than the delivery of electricity, including that related to street-lighting services, net transmission revenue, rate riders, deferrals and adjustments

Franchise Agreements

Most of FortisAlberta's residential, commercial and industrial customers located within a city, town, or village boundary are served through franchise agreements between the Company and the customers' municipality of residence. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta that are located in their municipal boundaries. In Alberta, the standard franchise agreement, which could include a franchise fee payable to the municipality, is generally for ten years and may be renewed for five years upon mutual consent of the parties. All municipal franchises are governed by legislation that requires the municipality or the utility to give notice and obtain AUC approval if it intends to terminate its franchise agreement. Any franchise agreement that is not renewed continues in effect until either the Company or the municipality terminates it with AUC permission. If a franchise agreement is terminated and the municipality subsequently exercises its right under the *Municipal Government Act* (Alberta) to purchase FortisAlberta's distribution network within the municipality's boundaries or annexed area, the Company must be compensated. Compensation would include payment for FortisAlberta's assets on the basis of replacement cost less depreciation.

FortisAlberta serves over 141 municipalities, of which 140 are on standardized individual franchise agreements. Substantially all of these agreements expire between 2011 and 2017. The Company is in the process of renewing or negotiating franchise agreements with one additional municipality and two summer villages.

Human Resources

At December 31, 2008, FortisAlberta had 991 full-time equivalent employees. Approximately 70 per cent of the employees of the Company are members of a labour association represented by UUWA, Local 200, under a three-year collective agreement that expires on December 31, 2010.

3.2.2 *FortisBC*

FortisBC includes FortisBC Inc., an integrated electric utility that owns a network of generation, transmission and distribution assets located in the southern interior of British Columbia. FortisBC Inc. serves a diverse mix of more than 157,000 customers, approximately 110,000 of whom are served directly by the Company's assets while the remainder are served through the wholesale supply of power to municipal distributors. In 2008, FortisBC Inc. met a record peak demand of 746 MW. Residential customers represent the largest customer segment of the Company. FortisBC's transmission and distribution assets include approximately 7,000 kilometres of transmission and distribution lines and 64 distribution substations.

FortisBC also includes operating, maintenance and management services relating to the 450-MW Waneta hydroelectric generation facility owned by Teck Cominco, the 149-MW Brilliant Hydroelectric Plant and 120-MW Brilliant Expansion Plant owned by CPC/CBT, the 185-MW Arrow Lakes Hydroelectric Plant owned by CPC/CBT, and the distribution system owned by the City of Kelowna.

Market and Sales

FortisBC has a diverse customer base composed primarily of residential, general service, industrial and municipal wholesale, and other industrial customers. Annual electricity sales were 3,087 GWh in 2008 compared to 3,091 GWh in 2007. Revenue increased to $237 million in 2008 from $229 million in 2007.

The following table compares the composition of FortisBC's 2008 and 2007 revenue and electricity sales by customer class.

FortisBC
Revenue and Electricity Sales by Customer Class

	Revenue *(per cent)*		**GWh Sales** *(per cent)*	
	2008	2007	**2008**	2007
Residential	**43.4**	40.7	**39.5**	37.5
General service	**24.6**	23.6	**23.4**	22.6
Wholesale	**19.3**	19.0	**28.9**	28.5
Industrial	**6.1**	8.4	**8.2**	11.4
Other (1)	**6.6**	8.3	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes revenue from sources other than from the sale of electricity, including revenue of Fortis Pacific Holdings associated with non-regulated operating, maintenance and management services*

Generation and Power Supply

FortisBC Inc. meets the electricity supply requirements of its customers through a mix of its own generation and power purchase contracts. FortisBC Inc. owns four regulated hydroelectric generating plants on the Kootenay River with an aggregate capacity of 223 MW and annual energy output of approximately 1,591 GWh, which provide approximately 45 per cent of the Company's energy needs and 30 per cent of its capacity needs. FortisBC Inc. meets the balance of its requirements through a portfolio of long-term and short-term power purchase contracts.

FortisBC Inc.'s four hydroelectric generation facilities are governed by the CPA. The CPA is a multi-party agreement that enables the five separate owners of eight major hydroelectric generating plants, with a combined capacity of more than 1,500 MW and located in relatively close proximity to each other, to coordinate the operation and dispatch of their plants.

The following table lists the plants and their owners.

Plant	Capacity (MW)	Owners
Canal Plant	580	BC Hydro
Waneta Dam	450	Teck Cominco
Kootenay River System	223	FortisBC Inc.
Brilliant Dam and Expansion	269	BPC and BEPC
Total	**1,522**	

BPC, BEPC, Teck Cominco and FortisBC Inc. are collectively defined in the CPA as the Entitlement Parties. 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 storage reservoirs, and through the coordinated operation of generating plants, to generate more power from their respective generating resources than they could if they operated independently. Under the CPA, BC Hydro takes into its system all power actually generated by all seven plants owned by the Entitlement Parties. In exchange for permitting BC Hydro to determine the output of these facilities, each of the Entitlement Parties is contractually entitled to a fixed annual entitlement of capacity and energy from BC Hydro, which is currently based on 50-year historical water flows. The Entitlement Parties receive their defined entitlements irrespective of actual water flows to the Entitlement Parties' generating plants and are, accordingly, insulated from the risk of water availability.

The majority of FortisBC Inc.'s remaining electricity supply is acquired through long-term power purchase contracts, consisting of the following:

i. a 149-MW long-term power purchase agreement with BPC terminating in 2056;
ii. a 200-MW power purchase agreement with BC Hydro terminating in 2013; and
iii. a number of small power purchase contracts with independent power producers.

The majority of these purchase contracts have been approved by the BCUC and prudently incurred costs thereunder flow through to customers through FortisBC Inc.'s electricity rates.

Although FortisBC Inc. can currently meet most of its customer supply requirements from its own generation and the long-term 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 incurred and accurately forecasted, are largely flowed through to customers. FortisBC Inc. generally makes arrangements prior to the winter season to acquire power at known prices should the need arise.

Legal Proceedings

The British Columbia Ministry of Forests has alleged breaches of the Forest Practices Code and negligence relating to a fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC. In addition, the Company has been served with a filed writ and statement of claim by a private landowner in relation to the same matter. The Company is currently communicating with its insurers and has filed a statement of defence in relation to all of the actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the Corporation's 2008 consolidated financial statements.

Human Resources

At December 31, 2008, FortisBC had 545 full-time equivalent employees. FortisBC had a collective agreement with IBEW, Local 213, which expired on January 31, 2009, and a collective agreement with COPE, Local 378, expiring on January 31, 2011. The two collective agreements cover approximately 75 per cent of employees. A new four-year collective agreement with IBEW, Local 213, was ratified by the union in February 2009.

3.2.3 *Newfoundland Power*

Newfoundland Power is the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving approximately 236,000 customers, or 85 per cent of the Province's electricity consumers. Newfoundland Power met a peak demand of 1,181 MW in 2008. The balance of the population is served by Newfoundland's other electric utility, Newfoundland Hydro, which also serves several larger industrial customers. Newfoundland Power owns and operates approximately 11,000 kilometres of transmission and distribution lines.

Market and Sales

Annual weather-adjusted electricity sales increased to 5,208 GWh in 2008 from 5,093 GWh in 2007. Revenue increased to $517 million in 2008 from $491 million in 2007.

The following table compares the composition of Newfoundland Power's 2008 and 2007 revenue and electricity sales by customer class.

Newfoundland Power
Revenue and Electricity Sales by Customer Class

	Revenue [(1)] *(per cent)*		**GWh Sales** [(1)] *(per cent)*	
	2008	2007	**2008**	2007
Residential	**58.9**	58.5	**60.1**	59.8
Commercial and Street Lighting	**37.3**	38.5	**39.9**	40.2
Other [(2)]	**3.8**	3.0	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Revenue and electricity sales reflect weather-adjusted values pursuant to Newfoundland Power's weather normalization reserve.*
(2) *Includes revenue from sources other than from the sale of electricity, the most significant being joint-use of pole revenue*

Power Supply

Approximately 92 per cent of Newfoundland Power's energy requirements is purchased from Newfoundland Hydro. The principal terms of the supply arrangements with Newfoundland Hydro are regulated by the PUB on a basis similar to that upon which Newfoundland Power's service to its customers is regulated.

Newfoundland Power operates 30 small generating stations which generate approximately 8 per cent of the electricity sold by Newfoundland Power. The Company's hydroelectric generating plants have a total capacity of 97 MW. The diesel plants and gas turbines have a total capacity of approximately 7 MW and 36 MW, respectively.

The City of St. John's has given formal notice of its intention to terminate Newfoundland Power's rights to use the Mobile River watershed for the generation of electricity. The effective date of the notice to terminate the lease was March 1, 2009. The Company held these rights under a lease dated November 23, 1946, which was amended by an agreement dated October 21, 1949. The two hydroelectric generating plants affected by the lease have a combined capacity of approximately 12 MW and generate annual production of 49 GWh, representing less than one per cent of the Company's total energy requirements. To exercise the termination provision of the lease, the City of St. John's is required to pay to the Company the value of all works and erections employed in the generation and transmission of electricity using the water of the Mobile River watershed. In accordance with the terms of the lease, an arbitration panel was appointed in 2008 for the purpose of determining the value of the affected assets. On March 9, 2009, the panel issued a ruling on certain preliminary questions. A majority of the panel ruled that termination of the lease will not be effective until payment to the Company of the value of the assets, and that the value payment is to be based on a valuation of the assets as a going concern, including the land and water rights. The ruling is subject to judicial review.

Human Resources

At December 31, 2008, Newfoundland Power had 551 full-time equivalent employees of which approximately 54 per cent were members of bargaining units represented by IBEW, Local 1620.

In September 2008, two collective agreements governing Newfoundland's unionized employees represented by IBEW, Local 1620, expired. In February 2009, one of the groups represented by IBEW, Local 1620, ratified a new collective agreement. This new collective agreement will be effective October 1, 2008 and will expire on September 30, 2011. The second collective agreement is subject to a conciliation process which began in March 2009.

3.2.4 *Other Canadian Electric Utilities*

Other Canadian Electric Utilities includes the operations of Maritime Electric and FortisOntario.

Maritime Electric

The Corporation, through Fortis Properties, holds all of the common shares of Maritime Electric. Maritime Electric operates an integrated electric utility which directly supplies approximately 73,000 customers, constituting 90 per cent of electricity consumers on Prince Edward Island. Maritime Electric purchases most of the energy it distributes to its customers from NB Power, a provincial Crown Corporation. Maritime Electric's system is connected to the mainland power grid via two submarine cables between Prince Edward Island and New Brunswick, which are leased from the Government of Prince Edward Island. Maritime Electric owns and operates generating plants with a combined capacity of 150 MW on Prince Edward Island and met a peak demand of 223 MW in 2008. Maritime Electric owns and operates approximately 5,300 kilometres of transmission and distribution lines.

FortisOntario

The Corporation's wholly owned regulated utility investments in Ontario, collectively FortisOntario, are composed of Canadian Niagara Power, including the operations of Port Colborne Hydro, and Cornwall Electric. Canadian Niagara Power services Fort Erie, Port Colborne and Gananoque, while Cornwall Electric services Cornwall. In total, FortisOntario's distribution operations serve approximately 52,000 customers. Canadian Niagara Power owns international transmission facilities at Fort Erie, Ontario and owns a 10 per cent interest in each of Westario Power Holdings Inc. and Rideau St. Lawrence, two regional electric distribution companies formed in 2000. FortisOntario met a combined peak demand of 227 MW in 2008. FortisOntario owns and operations approximately 1,570 kilometres of transmission and distribution lines.

Market and Sales

Annual electricity sales were 2,182 GWh in 2008 compared to 2,209 GWh in 2007. Revenue was $262 million in 2008 compared to $263 million in 2007.

The following table compares the composition of Other Canadian Electric Utilities' 2008 and 2007 revenue and electricity sales by customer class.

Other Canadian Electric Utilities Revenue and Electricity Sales by Customer Class				
	Revenue *(per cent)*		**GWh Sales** *(per cent)*	
	2008	2007	**2008**	2007
Residential	**43.4**	44.0	**42.4**	42.1
Commercial and industrial	**49.3**	49.8	**57.3**	57.6
Other [(1)]	**7.3**	6.2	**0.3**	0.3
Total	**100.0**	100.0	**100.0**	100.0

[(1)] *Includes revenue from sources other than from the sale of electricity*

Power Supply

Maritime Electric

Maritime Electric purchased more than 87 per cent of the electricity required to meet its customers' needs from NB Power in 2008. The balance was met through Maritime Electric's on-Island generation facilities and the purchase of wind energy produced on Prince Edward Island. Maritime Electric's generation facilities have a total installed capacity of 150 MW and are used primarily for peaking, submarine-cable loading issues and emergency purposes.

In 2008, approximately 5 per cent of the energy that Maritime Electric purchased from NB Power came from the Point Lepreau Station. The Point Lepreau Station began a major refurbishment in 2008 that will extend its estimated life to 2035. The cost of replacement energy during the refurbishment of the Point Lepreau Station is expected to be recovered from customers through the operation of the ECAM. To date, replacement costs for 2008 are being collected and costs for 2009 have been approved for deferral for future collection from customers, as approved by IRAC.

Legislation proclaimed by the Government of Prince Edward Island will see an increased reliance by Maritime Electric on renewable energy sources, such as wind-powered energy, located on Prince Edward Island. By 2013, Maritime Electric will be required to have a total of 30 per cent of its annual energy requirements from on-Island wind farms. In 2006, the Company signed an agreement with PEI Energy Corporation which will see the Company purchase 39 MW of wind-powered energy from PEI Energy Corporation's new wind farm. In 2008, 13 per cent of the Island's energy-supply requirements were generated by wind.

FortisOntario

The power requirements of FortisOntario's service areas are provided from various sources. Canadian Niagara Power purchases its power requirements for Fort Erie and Port Colborne from the IESO. Under the Standard Supply Code of the OEB, Canadian Niagara Power is obliged to provide Standard Service Supply to all its customers who do not choose to contract with an electricity retailer. This energy is provided to customers at either regulated or market prices.

Canadian Niagara Power purchases approximately 83 per cent of energy requirements for Gananoque through monthly energy purchases from Hydro One and the remaining 17 per cent is purchased from six hydroelectric generating plants owned by Fortis Properties.

Cornwall Electric purchases 100 per cent of its power requirements from Hydro-Québec Energy Marketing under two fixed-term contracts. The first contract, which represents approximately 37 per cent of the power supply, is a 45-MW contract with a 60 per cent capacity factor. The second contract, supplying the remainder of Cornwall Electric's energy requirement, is a 100-MW capacity and energy contract. Both contracts expire in December 2019.

Legal Proceedings

In April 2006, CRA reassessed Maritime Electric's 1997-2004 taxation years. The reassessment encompasses the Company's tax treatment, specifically the Company's timing of deductions, with respect to: (i) the ECAM in the 2001-2004 taxation years; (ii) customer rebate adjustments in the 2001 - 2003 taxation years; and (iii) the Company's payment of approximately $6 million on January 2, 2001 associated with a settlement with NB Power regarding its $450 million write-down of the Point Lepreau Station in 1998. Maritime Electric believes it has reported its tax position appropriately in all respects and has filed a Notice of Objection with the Chief of Appeals at CRA. In December 2008, the Appeals Division of CRA issued a Notice of Confirmation which confirmed the April 2006 reassessments. The Company will file an Appeal to the Tax Court of Canada.

Should the Company be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately $13 million in taxes and accrued interest. As at December 31, 2008, Maritime Electric has provided for this amount through future and current income taxes payable. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA. The amount currently on deposit with CRA arising from the reassessment is approximately $6 million.

Human Resources

At December 31, 2008, Maritime Electric had 179 full-time equivalent employees, of which approximately 70 per cent were represented by IBEW, Local 1432. The collective agreement with IBEW, Local 1432, expired on December 31, 2008. Maritime Electric and IBEW are currently negotiating a new collective agreement.

At December 31, 2008, FortisOntario had 125 full-time equivalent employees, of which approximately 64 per cent were represented by CUPE, Local 137, and IBEW, Local 636, in the Niagara Region and IBEW, Local 636, in Gananoque. The collective agreements governing these employees expire on April 30, 2009, May 31, 2009 and July 31, 2009, respectively.

3.3 Regulated Electric Utilities - Caribbean

Regulated Electric Utilities - Caribbean operations are comprised of Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos.

Belize Electricity, the principal distributor of electricity in Belize, Central America, serves approximately 74,000 customers, owns approximately 2,840 kilometres of transmission and distribution lines and met a peak demand of 74 MW in 2008. The Corporation holds an approximate 70 per cent controlling ownership interest in Belize Electricity.

Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 24,000 customers. The Company met a record peak demand of 94 MW in 2008. Caribbean Utilities owns and operates approximately 555 kilometres of transmission and distribution lines. Fortis has an approximate 57 per cent controlling ownership interest in Caribbean Utilities. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U). Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, its financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. Caribbean Utilities has changed its fiscal year end to December 31 which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008. Going forward, this change in the Company's fiscal year end will eliminate the previous two-month lag in consolidating its financial results.

Fortis Turks and Caicos, wholly owned by Fortis, serves more than 9,000 customers, or 85 per cent of electricity consumers, on the Turks and Caicos Islands and met a peak demand of 29 MW in 2008. Fortis Turks and Caicos owns and operates approximately 335 kilometres of transmission and distribution lines. The Company is the principal distributor of electricity on the Turks and Caicos Islands pursuant to 50-year licences that expire in 2036 and 2037.

Market and Sales

Annual electricity sales increased to 1,199 GWh in 2008 from 1,054 GWh in 2007. Annual revenue increased to $408 million in 2008 from $307 million in 2007.

The following table compares the composition of Regulated Electric Utilities - Caribbean's revenue and electricity sales by customer class for the years ended 2008 and 2007.

Regulated Electric Utilities – Caribbean *[(1) (2)]*
Revenue and Electricity Sales by Customer Class

	Revenue *[(3)]* *(per cent)*		**GWh Sales** *[(3)]* *(per cent)*	
	2008	2007	**2008**	2007
Residential	**46.8**	47.5	**47.2**	48.4
Commercial, industrial and street lighting	**51.9**	51.2	**52.8**	51.6
Other *[(4)]*	**1.3**	1.3	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) Includes Caribbean Utilities, Fortis Turks and Caicos, and Belize Electricity
(2) Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, its financial results were consolidated in the financial statements of Fortis on a two-month lag. Caribbean Utilities changed it fiscal year end to December 31 which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008. Revenue and GWh sales above include 14 months of data for Caribbean Utilities.
(3) The 2008 and 2007 figures are for the periods ended December 31, 2008 and 2007, respectively, and include 100 per cent of the revenue and electricity sales of Caribbean Utilities, Fortis Turks and Caicos, and Belize Electricity.
(4) Includes revenue from sources other than from the sale of electricity

Power Supply

In 2008, 67 per cent of the electricity needs of Regulated Electric Utilities - Caribbean were produced from gas and diesel-fired generation. The majority of the remainder was produced from hydroelectric generating facilities in Belize and purchased from CFE.

Belize Electricity meets its energy demand from multiple sources, which include power purchases from: (i) CFE, the Mexican state-owned power company; (ii) the Mollejon and Chalillo hydroelectric generating facilities owned and operated by BECOL; (iii) the Hydro Maya hydroelectric generating plant owned by Hydro Maya Limited; and (iv) its own diesel-fired and gas turbine generation. All major load centers are connected to Belize's national electricity system, which is connected with the Mexican national electricity grid, allowing Belize Electricity to optimize its power supply options. Belize Electricity purchased and produced 464 GWh of electricity in 2008, of which 98 per cent was purchased from CFE, the Mollejon and Chalillo hydroelectric generating facilities, and Hydro Maya Limited. The balance was produced by Belize Electricity's installed generating capacity of 34 MW, including a 23-MW gas-turbine generating facility.

Caribbean Utilities relies upon diesel-fired generation to produce electricity for Grand Cayman. Grand Cayman has neither hydroelectric potential nor inherent thermal resources and the Company must rely upon diesel fuel imported to Grand Cayman primarily from refineries in the Caribbean and the Gulf of Mexico. The Company has an installed generating capacity of approximately 137 MW.

Fortis Turks and Caicos relies upon diesel-fired generation, which has a combined generating capacity of 48 MW, to produce electricity for its customers.

Legal Proceedings

Belize Electricity is involved in a number of legal proceedings relating to the PUC's Final Decision on Belize Electricity's 2008/2009 Rate Application. For further information, refer to the "Material Regulatory Decisions and Applications" in section 4.0, "Regulation", of this 2008 Annual Information Form.

Human Resources

At December 31, 2008, Regulated Electric Utilities - Caribbean employed 570 full-time equivalent employees. The 197 employees at Caribbean Utilities and 95 employees at Fortis Turks and Caicos are non-unionized. Of the 278 full-time equivalent employees at Belize Electricity, approximately 59 per cent were represented by BEWU. The Company's collective agreement with BEWU was signed in July 2008 and is to be reviewed every five years.

3.4 Non-Regulated – Fortis Generation

The following table summarizes the Corporation's non-regulated generation assets by location.

Fortis Generation
Non-Regulated Generation Assets

Location	Plants	Fuel	Capacity (MW)
Belize [(1)]	2	hydro	32
Ontario	8	hydro, thermal	88
Central Newfoundland	2	hydro	36
British Columbia	1	hydro	16
Upper New York State	4	hydro	23
Total	**17**		**195**

(1) *Construction of a third plant, the 19-MW Vaca hydroelectric generating facility, commenced in 2007 and is expected to come into service at the beginning of 2010.*

The Corporation's non-regulated generation operations consist of its 100 per cent ownership interest in each of BECOL, FortisOntario Inc. and FortisUS Energy, as well as non-regulated generation assets owned by Fortis Properties and FortisBC Inc.

Non-regulated generation operations in Belize consist of the operations of the 25-MW Mollejon and the 7-MW Chalillo hydroelectric generating facilities. All of the output of these facilities is sold to Belize Electricity under a 50-year power purchase agreement expiring in 2055 and a franchise agreement with the Government of Belize. Under these agreements, the Mollejon hydroelectric generating facility will be transferred to the Government of Belize in 2036, after which it will be leased at an annually increasing rate for a term expiring in 2055.

Construction continued in 2008 on the US$53 million 19-MW hydroelectric generating facility at Vaca on the Macal River in Belize. The facility is being constructed downstream from the Chalillo and Mollejon hydroelectric generation facilities and is expected to increase average annual energy production from the Macal River by approximately 80 GWh to 240 GWh. Belize Electricity has signed a 50-year power purchase agreement for the purchase of the energy to be generated by the Vaca facility. At December 31, 2008, approximately $32 million (US$30 million) was incurred under this project.

Non-regulated generation operations of FortisOntario Inc. include 75 MW of water-right entitlement associated with the Niagara Exchange Agreement, which expires on April 30, 2009, and the operation of a 5-MW gas-fired cogeneration plant in Cornwall.

Fortis Properties, a non-regulated wholly owned subsidiary, holds a 51 per cent interest in the Exploits Partnership, the Corporation's non-regulated generation operations in central Newfoundland. The Exploits Partnership was established with Abitibi-Consolidated, which holds the remaining 49 per cent interest, to develop additional capacity at Abitibi-Consolidated's hydroelectric generating plant at Grand Falls-Windsor, Newfoundland and Labrador and redevelop Abitibi-Consolidated's hydroelectric generating plant at Bishop's Falls, Newfoundland and Labrador. These operations generate approximately 610 GWh annually, of which 470 GWh is utilized by Abitibi-Consolidated, while the remainder is sold to Newfoundland Hydro under a 30-year take-or-pay power purchase agreement, expiring in 2033, which is exempt from regulation. The assets of Fortis Properties also consist of six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW.

The non-regulated generation operations of FortisBC Inc., conducted through Walden, its wholly owned partnership, consist of the 16-MW run-of-river hydroelectric generating plant near Lillooet, British Columbia. This plant is a non-regulated operation that sells its entire output to BC Hydro under a power purchase agreement expiring in 2013.

Through FortisUS Energy, an indirect wholly owned subsidiary, the Corporation owns and operates four hydroelectric generating stations in Upper New York State with a combined capacity of approximately 23 MW operating under licences from FERC. All four hydroelectric generating stations sell energy at current market rates.

Market and Sales

Annual energy sales from non-regulated generation assets were 1,217 GWh in 2008 compared to 1,122 GWh in 2007. Revenue was $82 million in 2008 compared to $75 million in 2007.

The following table compares the composition of Fortis Generation's 2008 and 2007 revenue and energy sales by location.

Fortis Generation
Revenue and Energy Sales by Location

	Revenue *(per cent)*		**GWh Sales** *(per cent)*	
	2008	2007	**2008**	2007
Belize	**20.8**	21.2	**15.8**	14.9
Ontario	**42.7**	46.4	**58.8**	63.0
Central Newfoundland	**25.6**	23.0	**14.6**	12.2
British Columbia	**2.2**	2.3	**2.7**	3.0
Upper New York State	**8.7**	7.1	**8.1**	6.9
Total	**100.0**	100.0	**100.0**	100.0

Legal Proceedings

FortisUS Energy
During 2008, a statutory discontinuance and final release of FortisUS Energy was issued in relation to legal proceedings initiated by the Village of Philadelphia, New York. The Village had claimed that FortisUS Energy should honour a series of current and future payments set out in an agreement between the Village and a former owner of the hydroelectric site, located in the municipality of the Village, now owned by FortisUS Energy, totalling approximately $9 million (US$7 million). There was no impact on the Corporation's 2008 consolidated financial statements as a result of the settlement of these legal proceedings.

Exploits Partnership
On December 16, 2008, the Government of Newfoundland and Labrador passed legislation expropriating most of the Newfoundland assets of Abitibi-Consolidated. Prior to that date, Abitibi-Consolidated announced the closure of its Grand Falls-Windsor, Newfoundland newsprint mill, effective March 31, 2009. The hydroelectric generating facility assets of the Exploits Partnership were included as part of the expropriation legislation. The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi-Consolidated. The financial statements of the Exploits Partnership are consolidated in the financial statements of Fortis. The Exploits Partnership has a $61 million term loan, which is non-recourse to Fortis, with several lenders which is secured by the assets of the Exploits Partnership.

Discussions are ongoing with Exploits Partnership's lenders with respect to the above matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi-Consolidated. Pending resolution of these matters, the deferred financing costs of $2 million and utility capital assets of $61 million related to the Exploits Partnership have been reclassified to deferred charges and other assets and the $61 million term loan has been reclassified as current on the consolidated balance sheet of Fortis as at December 31, 2008.

Human Resources

At December 31, 2008, Fortis Generation employed 26 full-time equivalent personnel, none of whom participate in a collective agreement.

3.5 Non-Regulated – Fortis Properties

Fortis Properties owns and operates 20 hotels with more than 3,800 rooms in eight Canadian provinces and approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada. As a wholly owned subsidiary of Fortis, Fortis Properties is the Corporation's vehicle for non-utility diversification and growth.

Revenue was $207 million in 2008 compared to $191 million in 2007. In 2008, Fortis Properties derived approximately 30 per cent of its revenue from real estate operations and 70 per cent of its revenue from hotel operations. Fortis Properties derived approximately 43 per cent of its 2008 operating income from real estate operations and 57 per cent from hotel operations.

Fortis Properties' Real Estate Division is anchored by high-quality tenants under long-term leases. The Real Estate Division ended 2008 with 96.8 per cent occupancy, consistent with the rate at the end of 2007. In contrast, the average national occupancy rate was 93.3 per cent at the end of 2008 compared to 93.8 per cent at the end of 2007.

The following table sets out the office and retail properties owned by Fortis Properties.

Fortis Properties
Office and Retail Properties

Property	Location	Type of Property	Gross Lease Area *(square feet 000s)*
Fort William Building	St. John's, NL	Office	188
Cabot Place I	St. John's, NL	Office	135
TD Place	St. John's, NL	Office	94
Fortis Building	St. John's, NL	Office	83
Multiple Office	St. John's, NL	Office and Retail	75
Millbrook Mall	Corner Brook, NL	Retail	118
Fraser Mall	Gander, NL	Retail	99
Marystown Mall	Marystown, NL	Retail	87
Fortis Tower	Corner Brook, NL	Office	69
Viking Mall	St. Anthony, NL	Retail	69
Maritime Centre	Halifax, NS	Office and Retail	564
Brunswick Square	Saint John, NB	Office and Retail	512
Kings Place	Fredericton, NB	Office and Retail	292
Blue Cross Centre	Moncton, NB	Office and Retail	324
Delta Regina	Regina, SK	Office	52
Total			**2,761**

The Hospitality Division of Fortis Properties achieved higher revenue per available room for the 13th consecutive year increasing to $80.39 in 2008 from $79.31 in 2007. This increase was the result of improvements in average room rates in 2008, partially offset by lower average occupancy. The average daily rate increased to $120.23 in 2008 from $115.67 in 2007, while average occupancy for 2008 was 66.9 per cent, lower than the 68.6 per cent achieved in 2007.

In November 2008, Fortis Properties acquired the Fairmont Newfoundland hotel, increasing hospitality operations by 301 rooms and 16,000 square feet of convention space. The Fairmont Newfoundland hotel was rebranded the Sheraton Hotel Newfoundland in January 2009.

The hotels owned and managed by Fortis Properties are summarized as follows.

Fortis Properties Hotels			
Hotels	**Location**	**Number of Guest Rooms**	**Conference Facilities** *(square feet 000's)*
Delta St. John's	St. John's, NL	403	21
Holiday Inn St. John's	St. John's, NL	252	11
Sheraton Hotel Newfoundland [(1)]	St. John's, NL	301	16
Mount Peyton	Grand Falls-Windsor, NL	149	4
Greenwood Inn Corner Brook	Corner Brook, NL	102	5
Four Points by Sheraton Halifax	Halifax, NS	177	12
Delta Sydney	Sydney, NS	152	6
Delta Brunswick	Saint John, NB	254	18
Holiday Inn Kitchener-Waterloo	Kitchener-Waterloo, ON	184	13
Holiday Inn Peterborough	Peterborough, ON	153	7
Holiday Inn Sarnia	Point Edward, ON	217	11
Holiday Inn Cambridge	Cambridge, ON	143	7
Greenwood Inn Calgary	Calgary, AB	210	9
Greenwood Inn Edmonton	Edmonton, AB	224	8
Greenwood Inn Winnipeg	Winnipeg, MB	213	10
Ramada Hotel & Suites Lethbridge	Lethbridge, AB	119	5
Holiday Inn Express and Suites Medicine Hat	Medicine Hat, AB	93	1
Best Western Medicine Hat	Medicine Hat, AB	122	-
Holiday Inn Express Kelowna	Kelowna, BC	120	-
Delta Regina	Regina, SK	274	24
Total		**3,862**	**188**

[(1)] *Formerly Fairmont Newfoundland*

Human Resources

At December 31, 2008, Fortis Properties employed approximately 2,000 full-time equivalent employees, approximately 52 per cent of whom are represented by unions listed in the following table.

Fortis Properties Unions			
Property	**Union**	**Expiry of Agreement**	**Number of Unionized Employees**
Holiday Inn St. John's	CAW	August 31. 2009	53
Delta St. John's	UFCW	December 31, 2009	239
Greenwood Inn Corner Brook	CAW	March 11, 2010	41
East Side Mario's St. John's	CAW	July 31, 2010	80
Delta Sydney	CAW	September 30, 2008 [(1)]	81
Delta Brunswick & Brunswick Square	USW	June 10, 2010	133
Delta Regina	CEP	November 30, 2010	168
St. John's Real Estate	IBEW	April 17, 2010	11
Sheraton Newfoundland [(2)]	CAW	March 31, 2011	182
Mount Peyton	UFCW	December 1, 2011	45
Total			**1,033**

[(1)] *Delta Sydney has commenced union contract negotiations.*
[(2)] *Formerly Fairmont Newfoundland*

4.0 REGULATION

The nature of regulation and a summary of material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities are summarized as follows:

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2007	2008	2009	Supportive Features / Future or Historical Test Year Used to Set Rates
			ROE			
TGI	BCUC	35	8.37	8.62	8.47	COS/ROE PBR mechanism through 2009: TGI:50/50 sharing of earnings above or below the allowed ROE TGVI: 100 per cent retention of earnings from lower-than-forecasted operating and maintenance costs but no relief from increased operating and maintenance costs ROE automatic adjustment formula tied to long-term Canada bond yields
TGVI	BCUC	40	9.07	9.32	9.17	Future Test Year
FortisBC	BCUC	40	8.77	9.02	8.87	COS/ROE PBR mechanism for 2009 through 2011: 50/50 sharing of earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE – excess to deferral account ROE automatic adjustment formula tied to long-term Canada bond yields Future Test Year
FortisAlberta	AUC	37	8.51	8.75	8.51 [(1)]	COS/ROE ROE automatic adjustment formula tied to long-term Canada bond yields Future Test Year
Newfoundland Power	PUB	45	8.60 +/- 50 bps	8.95 +/- 50 bps	8.95 +/- 50 bps	COS/ROE ROE automatic adjustment formula tied to long-term Canada bond yields Future Test Year
Maritime Electric	IRAC	40	10.25	10.00	9.75	COS/ROE Future Test Year
FortisOntario	OEB (Canadian Niagara Power) Franchise Agreement (Cornwall Electric)	43.3 [(2)]	9.00	9.00	8.39	Canadian Niagara Power - COS/ROE Cornwall Electric - Price cap with commodity cost flow through Future Test Year – beginning in 2009
			ROA			
Belize Electricity	PUC	N/A	10.00 - 15.00	10.00	10.00 [(3)]	Four-year COS/ROA agreements Additional costs in the event of a hurricane would be deferred and the Company may apply for future recovery in customer rates. Future Test Year
Caribbean Utilities	ERA	N/A	15.00	9.00 - 11.00	9.00 - 11.00	COS/ROA Rate-cap adjustment mechanism based on published consumer price indices Under the new licences, the Company may apply for a special additional rate to customers in the event of a disaster, including a hurricane. Historical Test Year
Fortis Turks and Caicos	Utilities make annual filings with the Energy Commission	N/A	17.50 [(4)]	17.50 [(4)]	17.50 [(4)]	COS/ROA If the actual ROA is lower than the allowed ROA, due to additional costs resulting from a hurricane or other event, the Company may apply for an increase in customer rates in the following year. Future Test Year

(1) Interim ROE pending the outcome of the AUC's 2009 Generic Cost of Capital Proceeding
(2) Allowed deemed equity component of the capital structure for 2009. For 2008, the allowed deemed equity component of the capital structure was 46.7 per cent.
(3) Based on the June 2008 Final Decision on Belize Electricity's 2008/2009 rate application
(4) Amount provided under licence. Actual ROAs achieved in 2007 and 2008 were lower than the ROA allowed under the licence due to significant investment occurring at the utility.

Material Regulatory Decisions and Applications	
Regulated Utility	**Summary Description**
TGI/TGVI	• In December 2007, the BCUC approved various rates at TGI and TGVI, including those for mid-stream and delivery for residential customers in several service areas, effective January 1, 2008. Increased mid-stream costs are flowed through to customers without markup. The approved rates also reflected the impact of an increase in the allowed ROE for 2008 to 8.62 per cent and 9.32 per cent for TGI and TGVI, respectively. • On April 1, 2008, final regulatory approval for the construction of the 1.5 billion-cubic foot liquefied natural gas storage facility on Vancouver Island was received for a total estimated cost of approximately $200 million. • Every three months, TGI and TGVI review natural gas and propane commodity prices with the BCUC in order to ensure the flow-through rates charged to customers are sufficient to cover the cost of purchasing natural gas and propane. Effective April 1, 2008 and July 1, 2008, the BCUC approved increases in the commodity rates charged to TGI customers for natural gas and propane. Effective October 1, 2008, the BCUC approved decreases in the commodity rates charged to TGI customers for natural gas. The commodity cost of natural gas and propane are flowed through to customers without markup. During 2008, no commodity rate changes were made at TGVI. • In December 2008, the BCUC approved various rates at TGI and TGVI, including those for mid-stream and delivery for residential customers in several service areas, effective January 1, 2009. The approved rates also reflected the impact of a decrease in the allowed ROE for 2009 to 8.47 per cent and 9.17 per cent for TGI and TGVI, respectively, resulting from the application of automatic ROE adjustment mechanisms. The commodity rate for natural gas will remain unchanged and the commodity rate for propane will decrease effective January 1, 2009. • TGI filed an application with the BCUC in the fourth quarter of 2008 requesting approval to perform extensive rehabilitation of certain underwater transmission pipeline crossings of the South Arm of the Fraser River serving Vancouver and Richmond. TGI expects to receive regulatory approval for this $27 million project in early 2009 with completion of the project anticipated in 2010. • TGI and TGVI are currently preparing rate applications related to 2010 which are anticipated to be filed with the BCUC in the second quarter of 2009. The BCUC approval of rates for 2010 and future years will be required as the current PBR agreements expire at the end of 2009. As part of the rate filings, TGI and TGVI plan to seek a review of the current generic ROE adjustment mechanisms and the deemed equity component of the utilities' capital structures.
FortisBC	• In December 2007, regulatory approval was received for the NSA associated with 2008 revenue requirements, resulting in a customer rate increase of 2.9 per cent, effective January 1, 2008. The rate increase was primarily the result of the Company's capital expenditure program. Rates for 2008 reflected an allowed ROE of 9.02 per cent. • In April 2008, the BCUC approved an interim increase of 0.8 per cent to FortisBC's customer rates, effective May 1, 2008, as a result of BC Hydro's interim rate increase, which increased FortisBC's cost to purchase power from BC Hydro by 5.06 per cent. • In June 2008, FortisBC filed its 2009 and 2010 Capital Expenditure Plan for gross capital expenditures of approximately $193 million for 2009 and $196 million for 2010. In November 2008, the BCUC denied the costs relating to the Copper Conductor Replacement Project and Advanced Metering Infrastructure Project included in the 2009 and 2010 Capital Expenditure Plan. These projects would have totalled approximately $21 million in 2009 and $27 million in 2010. In February 2009, the BCUC issued its decision on the Company's 2009 and 2010 Capital Expenditure Plan. Total gross capital expenditures of $165 million were approved for 2009 and $156 million were approved for 2010. An additional $16 million of capital expenditures is subject to further regulatory processes. • In December 2008, the BCUC approved the Company's 2009 Revenue Requirements Application resulting in a general rate increase of 4.6 per cent, effective January 1, 2009. The rate increase is primarily the result of the Company's capital expenditure program and higher power purchases driven by customer growth and increased electricity demand. Rates for 2009 reflect an allowed ROE of 8.87 per cent as a result of the application of the automatic ROE adjustment mechanism. The approval of the 2009 Revenue Requirements Application also included an extension of the PBR mechanism for the years 2009 through 2011 under terms similar to the previous PBR agreement, except annual gross operating and maintenance expenses, before capitalized overhead, will be set by a formula incorporating customer growth and inflation, i.e., the 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 is to be added to the PIF, which effectively caps the CPI at 3 per cent.
FortisAlberta	• Effective January 1, 2008, FortisAlberta became regulated by the AUC due to the separation of the Alberta Energy and Utilities Board into two separate regulatory bodies. • In February 2008, regulatory approval was received of the NSA associated with 2008/2009 revenue requirements, resulting in distribution rate increases of 6.8 per cent, effective January 1, 2008, and 7.3 per cent, effective January 1, 2009. The approved NSA includes forecast gross capital expenditures of approximately $264 million for 2008 and $296 million for 2009, primarily to meet customer growth and improve system reliability. The 2008 revenue requirements included in the 2008/2009 NSA were determined using the 2007 allowed ROE of 8.51 per cent. The impact of the increase in the allowed ROE to 8.75 per cent for 2008 was subject to deferral-account treatment and, as such, was recognized as earned in 2008 and will be collected in customer rates in 2009.

Material Regulatory Decisions and Applications (continued)	
Regulated Utility	**Summary Description**
FortisAlberta (continued)	• In June 2008, the AUC ruled that a review of ROE levels, adjustment mechanisms and utility capital structures in a generic proceeding would be appropriate. In July 2008, the AUC issued its notice of application, preliminary scoping document and minimum filing requirements for the 2009 Generic Cost of Capital Proceeding. The proceeding applies to all gas, electric and pipeline utilities in Alberta that are regulated by the AUC. • In November 2008, FortisAlberta submitted its evidence with respect to the 2009 Generic Cost of Capital Proceeding as requested by the AUC. A hearing is scheduled for the second quarter of 2009. • In December 2008, FortisAlberta received regulatory approval for its 2009 distribution rates to recover approved distribution costs. The result is a distribution rate increase of 8.6 per cent, effective January 1, 2009. The rate increase is slightly higher than the rate increase of 7.3 per cent contemplated in the 2008/2009 NSA due to the deferred recovery in customer rates in 2009 of the increase in the allowed ROE to 8.75 per cent in 2008. The approved rates for 2009 also reflect the impact of the Company's union agreement, which was settled after the 2008/2009 NSA was approved. As directed by the AUC, the Company is to continue using the 2007 allowed ROE of 8.51 per cent for 2009, pending the outcome of the 2009 Generic Cost of Capital Proceeding. • FortisAlberta expects to file a 2010 and 2011 revenue requirements application during the second quarter of 2009.
Newfoundland Power	• In December 2007, the PUB approved the Company's NSA associated with the 2008 general rate application, resulting in an average 2.8 per cent increase in customer rates, effective January 1, 2008. The rate increase was largely driven by higher amortization costs. The rate increase also reflected the impact of an increase in the allowed ROE to 8.95 per cent for 2008. • The PUB-approved NSA also results in, among other things: (i) the amortization of $7.2 million in 2008 and $4.6 million in each of 2009 and 2010 of the remaining $16.4 million balance of the original December 2005 unbilled revenue liability; (ii) amortization of approximately $3.9 million in each of 2008, 2009 and 2010 of previously deferred amortization expense; (iii) amortization over a period of three years to five years of certain deferred regulatory balances; and (iv) for 2008 through 2010, the deferral of variations in purchase power expense caused by differences in the actual unit cost of energy and the unit cost reflected in customer rates to be recovered from, or refunded to, customers through operation of the Company's rate stabilization account. • Effective July 1, 2008, the PUB approved an average 5.9 per cent increase in customer electricity rates, reflecting the flow through to customers, by operation of the rate stabilization account, of variances in the cost of fuel used to generate electricity that Newfoundland Hydro sells to Newfoundland Power. The increase in customer rates had no impact on Newfoundland Power's earnings in 2008. • In November 2008, the PUB approved, as filed, the Company's 2009 Capital Budget Application for approximately $62 million, with approximately half of the proposed capital expenditures relating to replacing aged and deteriorated components of the electricity system. • The Company's allowed ROE of 8.95 per cent remains unchanged for 2009 and, consequently, there has been no change in basic customer rates for 2009.
Maritime Electric	• In January 2008, IRAC approved, as filed, an increase in basic electricity rates of 1.8 per cent, effective April 1, 2008, and approved a maximum allowed ROE of 10.0 per cent for 2008. • In April 2008, IRAC ordered the ECAM amortization period of 12 months to be set at 8 months, effective May 1, 2008. The result is an increase in the flow through in customer rates of the recovery of ECAM over the shorter amortization period. • In September 2008, IRAC approved, as filed, the Company's amendment of approximately $14 million to its 2008 Capital Budget to reflect the construction of a new transmission line to facilitate the expansion of merchant wind development. The project is being financed entirely by customer contributions. • In November 2008, IRAC approved, as filed, the Company's 2009 Capital Budget Application for approximately $20 million, before customer contributions. • In March 2009, IRAC approved Maritime Electric's 2009 Rate Application, which will result in an increase in the amount of energy-related costs to be collected from customers through the basic rate component of customer billings, effective April 1, 2009. The increase in the reference cost of energy in basic rates from 6.73 cents per kWh to 7.7 cents per kWh will result in a decrease in the amount of energy costs to be collected from customers through the operation of the ECAM. Additionally, IRAC approved the deferral of Point Lepreau Station replacement energy costs for 2009 and an increase in the amortization of the ECAM to 12 months, effective April 1, 2009. IRAC also approved, as filed, a maximum allowed ROE of 9.75 per cent for 2009, down from an allowed ROE of 10.00 per cent for 2008. The overall impact on residential customer rates for 2009 will be an increase of 5.3 per cent based on average consumption of 650 kWh per month.
FortisOntario	• In March 2008, the OEB issued its decision relating to the 2008 IRM application filed by Canadian Niagara Power. The result was an average 1.1 per cent increase in electricity distribution rates for operations in Fort Erie, Port Colborne and Gananoque, effective May 1, 2008. The increase was comprised of a 2.1 per cent increase for inflation, partially offset by a 1.0 per cent decrease for a productivity adjustment. Under the 2008 IRM, Canadian Niagara Power's capital structure for 2008 was deemed at 53.3 per cent debt and 46.7 per cent equity, as part of the OEB's plan to move to a 60 per cent debt and 40 per cent equity capital structure over a three-year period. • Effective July 1, 2008, retail rates at Cornwall Electric decreased by approximately 6.2 per cent, attributable to a new 11.5-year wholesale electricity supply contract negotiated with Hydro-Québec Energy Marketing by Cornwall Electric on behalf of its customers. The new long-term agreement replaces an existing short-term contract and ensures reliability of supply and rate stability.

Material Regulatory Decisions and Applications (continued)	
Regulated Utility	**Summary Description**
FortisOntario (continued)	• In August 2008, Canadian Niagara Power filed a 2009 Cost of Service Application requesting the rebasing of distribution rates using 2009 as a forward test year. The application assumes a deemed capital structure of 56.7 per cent debt and 43.3 per cent equity and, as required by the OEB, reflects a preliminary ROE of 8.39 per cent. The application proposes distribution rate increases of 4.9 per cent, 9.4 per cent and 7.1 per cent for Fort Erie, Gananoque and Port Colborne, respectively, effective May 1, 2009. The proposed increases are primarily driven by the impact of distribution system upgrades. The hearing process associated with the application commenced during the fourth quarter of 2008 and the Company expects a decision on the application to be received in April 2009.
Belize Electricity	• In March 2008, the newly elected Government of Belize repealed December 2007 amendments to the *Electricity (Tariffs, Charges and Quality of Services Standards) Bylaws*. The amendments had simplified Belize Electricity's rate-setting methodology, allowed for improved rate stabilization and settled outstanding matters related to the PUC's Final Decision on electricity rates for the period July 1, 2007 through June 30, 2008. • In March 2008, Belize Electricity filed an application requesting an increase in the cost of power component of the average electricity rate by 15 per cent, or BZ6.5 cents per kWh, as a result of the rapid increase in the cost of power due to increasing world oil prices. The application was disallowed by the PUC which cited that, in the interim, a decrease in the Company's operating expenses and capital expenditure levels would help offset the impact on cash flow of the increasing cost of power. Additionally, the PUC indicated it would defer its detailed analysis of the high deferrals of cost of power into Belize Electricity's CPRSA until the Annual Tariff Review Proceeding for the annual tariff period for July 1, 2008 to June 30, 2009. • In April 2008, Belize Electricity filed its Annual Tariff Review Application for the annual tariff period from July 1, 2008 to June 30, 2009 ("2008/2009 Rate Application") requesting a 13.4 per cent increase in the average electricity rate, as a result of an increase in the cost of power component of the rate and an increase in the recovery of the CPRSA. • In May 2008, the PUC issued its Initial Decision on Belize Electricity's 2008/2009 Rate Application. The Initial Decision denied any average rate increase and approved, among other things, a retroactive adjustment to Belize Electricity's CPRSA. Belize Electricity objected to the Initial Decision, which resulted in a review of the Initial Decision by a PUC-appointed Independent Expert. The report of the Independent Expert reiterated many of Belize Electricity's concerns pertaining to the Initial Decision. • In June 2008, the PUC issued its Final Decision on Belize Electricity's 2008/2009 Rate Application which rejected most of the recommendations of the Independent Expert and failed to increase the overall average electricity rate. The PUC also ordered a BZ$36 million retroactive adjustment associated with Belize Electricity's prior years' financial results. The adjustment, in substance, represented the disallowance of previously incurred fuel and purchased power costs. The PUC also reduced Belize Electricity's targeted allowed ROA to 10 per cent from 12 per cent through a reduction in the VAD component of the average electricity rate. The Final Decision would have the impact of reducing the Corporation's share of Belize Electricity's earnings by approximately $5 million over a 12-month period. The Final Decision does not impact the Corporation's non-regulated generation operations in Belize. • As a direct result of the Final Decision, Belize Electricity recorded an $18 million (BZ$36 million) charge ($13 million of which was the Corporation's share) to energy supply costs during the second quarter of 2008. • The Final Decision also proposed the use of an automatic mechanism, to be finalized by the PUC, to adjust monthly, on a two-month lag basis, the cost of power component of the rate to reflect actual costs of power. The automatic adjustment mechanism, which was retroactive effective September 1, 2008, allows for the collection from, or rebate to, customers of actual costs of power which vary from a reference cost of power by more than a threshold of 10 per cent. • In February 2009, the PUC amended the Final Decision on Belize Electricity's 2008/2009 Rate Application (the "Amendment"), effective for the period from January 1, 2009 through June 30, 2009. The Amendment provides for an increase in the VAD component of the average electricity rate to allow Belize Electricity to earn a targeted allowed ROA of 12 per cent but reduces the reference cost of power component of the average electricity rate, due to an overall decline in the cost of power. The Amendment, therefore, allows for an overall decrease in the average electricity rate from BZ44.1 cents per kWh to BZ37.5 cents per kWh. The Amendment also provides for a lower regulated asset value upon which the allowed ROA is calculated, while increasing operating expenses by the same amount, and reduces depreciation, taxes and fees and the related revenue requirement. • Changes made in electricity legislation by the Government of Belize and the PUC and the June 2008 Final Decision and Amendment, which were based on the changed legislation, have been judicially challenged by Belize Electricity in several proceedings. The judicial process is ongoing with interim rulings, judgments and appeals. The timing or likely outcome of the proceedings is indeterminable at this time.

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<tr><th colspan="2">Material Regulatory Decisions and Applications (continued)</th></tr>
<tr><th>Regulated Utility</th><th>Summary Description</th></tr>
<tr><td>Caribbean Utilities</td><td>
In December 2007, an AIP was reached with the Government of the Cayman Islands on the terms of a new exclusive T&D licence and a new non-exclusive generation licence.
In April 2008, the new licences were granted. The terms of the new licences included competition for future generation capacity and general promotion of renewable sources of energy. The T&D licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. The generation licence is for a period of 21.5 years, expiring September 2029. The terms of the new licences remained substantially the same as the terms outlined in the AIP.
Effective January 1, 2008, as a result of the AIP and subsequent granting of the new licences, basic customer rates were reduced by 3.25 per cent, the hurricane CRS was removed, a fuel-duty rebate funded by the Government of the Cayman Islands was implemented for residential customers consuming less than 1,500 kWh monthly, and basic rates were restructured to extract all fuel costs and licence fee amounts, which are now being flowed through to customers. The 3.25 per cent reduction in basic rates reduced annual revenue by approximately US$2.1 million. Additionally, Caribbean Utilities has forgone US$2.6 million of revenue in 2008, as a result of the early elimination of the hurricane CRS. A new fuel and oil rate factor was also established to provide for the full flow through of fuel and oil costs to customers.
Following the initial basic rate reduction, customer rates will be frozen until May 31, 2009 and will be subject to annual review and adjustment each June thereafter. Under the new T&D licence, a mechanism will be used to adjust basic rates in accordance with a formula that is based on published CPIs, thereby taking inflation into account. The rate-adjustment mechanism is designed to maintain Caribbean Utilities' allowed ROA in a targeted range of 9 per cent to 11 per cent, down from an allowed ROA of 15 per cent permitted under the previous licence. The recently amended Electricity Regulatory Authority Law (2005 Revision) provides for the conduct of a competitive bid process to be managed by the ERA for new generating capacity and the replacement of retired generating capacity. The first competitive process under the new generation licence began in May 2008 with a filing of a Certificate of Need by Caribbean Utilities for the installation of 16 MW of additional generating capacity in each of 2011 and 2012. Based on slowing economic growth, the Company has advised the ERA that the capacity is not required until a year later. In March 2009, the ERA approved the Certificate of Need for 16 MW of generating capacity in each of 2012 and 2013.
In July 2008, Caribbean Utilities began a formal request for expressions of interest from qualified wind-generation developers for a wind-generation project for up to 10 MW. The ERA has endorsed this initiative and any power purchase agreements or generating licence arising from this initiative will be subject to ERA approval.
In July 2008, Caribbean Utilities filed with the regulator a Five-Year CIP totalling US$255 million.
In December 2008, Caribbean Utilities filed with the regulator a revised Five-Year CIP as a result of the change in the Company's fiscal year end. The revised CIP still totalled US$255 million, including approximately US$72 million related to new generation that is expected to be solicited. In January 2009, the regulator requested that the Company further review its non-generation capital expenditures to reflect the current economic environment and lower growth projections. A revised CIP totaling US$246 million was subsequently submitted to the ERA. A decision on the revised CIP is expected during the first quarter of 2009.
In January 2009, the ERA approved a new customer-owned renewable energy tariff that will allow customers on Grand Cayman to connect renewable energy systems to the Company's distribution system and generate their own power from renewable energy while remaining connected to Caribbean Utilities' grid. The Company expects to be able to connect customers to the grid by the end of the first quarter of 2009.
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<tr><td>Fortis Turks and Caicos</td><td>
In May 2008, Fortis Turks and Caicos received approval from the Government of the Turks and Caicos Islands to supply wholesale electricity under an exclusive licence to Dellis Cay on the Turks and Caicos Islands.
In March 2009, Fortis Turks and Caicos submitted its 2008 annual regulatory filing outlining the Company's performance in 2008 and its capital expansion plans for 2009.
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5.0 ENVIRONMENTAL MATTERS

The Corporation and its Canadian subsidiaries are subject to federal, provincial and municipal laws, regulations and guidelines relating to the protection of the environment including, but not limited to, wildlife, water and land protection and the proper storage, transportation, recycling and disposal 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 their commencement.

Several key Canadian federal environmental laws and regulations affecting the operations of the Corporation's Canadian subsidiaries include, but are not limited to, the (i) *Canadian Environmental Assessment Act;* (ii) *Canadian Environmental Protection Act*; (iii) *Transportation of Dangerous Goods Act and Regulations*; (iv) *Hazardous Product Act*; (v) *Canada Wildlife Act*; (vi) *Navigable Waters Protection Act*; (vii) *Canada National Parks Act*; (viii) *Fisheries Act; (ix) Canada Water Act; (x) National Emission Guidelines for Stationary Combustion Turbines; (xi) National Fire Code of Canada; (xii) Pest Control Products Act and Regulations; (xiii) Storage of PCB Material Regulations; (xiv) Canadian Species at Risk Act; and (xv) Ozone Depleting Substances Regulations.*

There are many Canadian provincial and municipal laws, regulations and guidelines that address similar environmental risks as the federal laws, regulations and guidelines, but at a local level.

In British Columbia, the *Carbon Tax Act* and *Greenhouse Gas Reduction Targets Act* specifically affect, or may potentially affect, the operations of the Terasen Gas companies and FortisBC as is described later.

While there are environmental laws, regulations and guidelines affecting the Corporation's operations in Grand Cayman and Turks and Caicos, and Belize, they are less extensive than the laws, regulations and guidelines in Canada.

Environmental risks affecting the Corporations' utility operations include, but are not limited to: (i) hazards associated with the storage and handling of large volumes of fuel at fuel-fired electricity generating plants, including leeching of the fuel into the ground and nearby watershed areas; (ii) risk of spilling or leaking petroleum-based products, including PCB-contaminated oil, which are used in the cooling and lubrication of transformers, capacitors and other electrical equipment; (iii) greenhouse gas emissions, including natural gas and propane leaks and spills and emissions from the combustion of fuel required to generate electricity; (iv) risk of fire; (v) risk of contamination of air, soil or land associated with the improper handling, storage, transportation and disposal of other hazardous substances; (vi) risk of disruption to vegetation; (vii) risk of contamination of soil and water near chemically treated poles; (viii) risk of disruption to fish, animals and their habitat as a result of the creation of artificial water flows and levels associated with hydroelectric water storage and utilization; and (ix) risk of responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner.

The key focus of the utilities is to provide reliable cost-effective service with full regard for the safety of employees and the public while operating in an environmentally responsible manner. A focus on safety and the environment is, therefore, an integral and continuing component of the Corporation's operating activities. The environmental policies vary among the Corporation's utilities depending on the specific environmental laws, regulations and guidelines applicable to their operations and jurisdiction. However, the policies are implemented and reinforced through the use of environmental management systems. Common elements of the utilities' environmental management systems include: (i) regular inspections of fuel and oil-filled equipment in order to identify and correct for potential spills, and spill response systems to ensure that all spills are addressed, and the associated cleanup is conducted in a prompt and environmentally responsible manner; (ii) greenhouse gas emissions management; (iii) procedures for handling, transporting, storing and disposing of hazardous substances, including chemically treated poles, asbestos, lead and mercury; (iv) programs to mitigate fire-related incidents; (v) programs for the management and/or elimination of PCBs; (vi) vegetation management programs; (vii) training of and communicating of environmental policies to employees to ensure work is conducted in an environmentally responsible manner; (viii) review of work practices that affect the environment; (ix) waste management programs; (x) environmental emergency response procedures; (xi) environmental site assessments; and (xii) environmental incident reporting procedures.

The Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario have developed their respective environmental management systems consistent with the guidelines of ISO 14001, an internationally recognized standard for environmental management systems. Caribbean Utilities operates an environmental management system associated with its generation operations, which is ISO 14001 certified, and uses an environmental management system for its transmission and distribution operations, which is consistent with ISO 14001 guidelines. Belize Electricity has implemented an environmental management system with the intention of it becoming consistent with ISO 14001 guidelines by the end of 2010. Fortis Turks and Caicos plans to implement an environmental management system in 2009 that will be consistent with ISO 14001 standard by 2012. As part of their respective environmental management systems, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor performance. External and internal audits of the environmental management systems are performed on a periodic basis. Based on audits completed in 2008, the environmental management systems continue to be effective and materially consistent with ISO 14001 guidelines. In 2008, an external audit conducted on Caribbean Utilities' environmental management system associated with its generation operations verified the system remained ISO 14001 certified.

Environmental risks associated with the Corporation's non-regulated generation operations are either addressed by environmental management systems of the Corporation's regulated electric utilities or by environmental practices and procedures followed by Fortis Properties.

For the Corporation's regulated gas utilities, air emissions management is the main environmental concern primarily due to the uncertainties relating to emerging federal and provincial greenhouse gas regulations. While governmental policy direction is starting to unfold, it remains to be determined to what extent a greenhouse air emissions cap will impact these utilities. To mitigate this uncertainty, the Terasen Gas companies participate in sectoral and industry groups to help develop the emerging regulation. In addition, TGI was an active participant in Canada's Voluntary Climate Change Challenge and Registry and, its successor, the Canadian Greenhouse Gas Challenge Registry.

Recent updates to the Government of British Columbia's Energy Plan and greenhouse gas reduction targets present risks and opportunities to the Terasen Gas companies and, to a lesser degree, FortisBC. The *Greenhouse Gas Reduction Targets Act* mandates a province-wide reduction in greenhouse gases of 33 per cent from 2007 levels. This is coupled with mandates for all new electricity generation to be net carbon neutral, and for British Columbia to be electrically self-sufficient by 2016.

Energy and emissions policies in British Columbia also present a number of opportunities. The policies have created incentives to expand Terasen's deployment of renewable energy, such as biogas, and to expand the Company's Energy Efficiency and Conservation Program. Additionally, the introduction of the *Carbon Tax Act* improves the position of natural gas relative to other fossil energy, as the tax is based on the amount of carbon dioxide equivalent emitted per unit energy. Natural gas, therefore, has a lower tax rate than oil or coal products.

British Columbia is a participant in the Western Climate Initiative. The participants, consisting of several states and provinces, plan to implement a cap-and-trade program to reduce greenhouse gas emissions. The program begins on January 1, 2012. At that time, Terasen expects to have one facility, the Terasen Gas (Vancouver Island) Inc. transmission system, covered under the program. This facility will be required to reduce emissions to meet a declining cap on emissions, or to purchase emissions allowances to cover emissions over the capped amount. While allowance costs are based on market prices that have little clarity at present, it appears likely that this facility will be a net purchaser of allowances over the near and medium term. Allowances will likely be issued to mirror the emission reduction mandate of the Government of British Columbia, such that emissions will need to be reduced by 33 per cent over 2007 amounts by 2020.

The key environmental risks affecting the Corporation's hospitality and real estate operations include, but are not limited to: (i) risk of asbestos and urea-formaldehyde contamination in buildings; (ii) risk of release of ozone-depleting substances from air conditioning and refrigeration equipment; (iii) fuel tank leaks; and (iv) risk of responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. Fortis Properties is committed to meeting the requirements of environmental standards related to its hospitality and real estate operations. In assessing new properties, all buildings and hotels must meet environmental standards, including, but not limited to, the appropriate federal, provincial and municipal standards for asbestos, fuel storage, urea-formaldehyde and chlorofluorocarbon-based refrigerants in air conditioning and refrigerating equipment. This process is also applied to existing properties, ensuring environmental compliance by all facilities.

The Corporation has asset-retirement obligations as disclosed in the Notes to the 2008 consolidated financial statements of Fortis. However, liabilities with respect to these asset retirements obligations have not been recorded in the Corporation's 2008 Consolidated Financial Statements as they could not be reasonably estimated or were determined to be immaterial (including asset retirement obligations associated with PCBs, asbestos and chemically treated poles) to the Corporation's consolidated results of operations, cash flows or financial position.

Costs associated with environmental protection initiatives (including the development, implementation and maintenance of environmental management systems), compliance with environmental laws, regulations and guidelines, and environmental damage were not material to the Corporation's consolidated results of operations, cash flows or financial position and, based on current laws, facts and circumstances, are not expected to have a material effect in the future. At the Corporation's regulated utilities, prudently incurred operating and capital costs associated with environmental protection initiatives, compliance with environmental laws, regulations and guidelines, and environmental damage are eligible for recovery in customer rates. The Corporation believes that it and its subsidiaries are materially compliant with environmental laws and regulations applicable to them in the various jurisdictions in which they operate.

6.0 RISK FACTORS

The following is a summary of the Corporation's significant business risks.

Regulatory Risk: The Corporation's key business risk is regulation. Each of the Corporation's regulated utilities is subject to some form of regulation that can affect future revenue and earnings. Management at each utility is responsible for working closely with regulators and local governments to ensure both compliance with existing regulations and the proactive management of regulatory issues.

Approximately 93 per cent of the Corporation's operating revenue was derived from regulated utility operations in 2008 (2007 - 90 per cent), while approximately 83 per cent of the Corporation's operating earnings, before corporate and other net expenses, were derived from regulated utility operations in 2008 (2007 - 81 per cent). The regulated utilities - Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity, Caribbean Utilities, and Fortis Turks and Caicos - are subject to the normal uncertainties faced by regulated entities. The uncertainties include regulatory approvals of gas and electricity rates that permit a reasonable opportunity to recover, on a timely basis, the estimated costs of providing services, including a fair rate of return on rate base. Generally, the ability of the utilities to recover the actual costs of providing services and earn the approved rates of return depends on achieving the forecasts established in the rate-setting processes. Upgrades of existing gas and electricity systems and facilities and the addition of new infrastructure and facilities require the approval of the regulatory authorities either through the approval of capital expenditure plans or through regulatory approval of revenue requirements for the purpose of setting rates, which include the impact of capital expenditures on rate base and/or cost of service. There is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed. Capital cost overruns subject to such approvals might not be recoverable. In addition, there is no assurance that the regulated utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

Rate applications that establish revenue requirements may be subject to negotiated settlement procedures, as well as pursued through public hearing processes. There can be no assurance that rate orders issued will permit the Corporation's utilities to recover all costs actually incurred and earn the expected rates of return. A failure to obtain acceptable rate orders may adversely affect the business carried on by the utilities, the undertaking or timing of proposed capital projects, ratings assigned by rating agencies, the issuance and sale of securities, and other matters, which may, in turn, negatively affect the results of operations and financial position of the Corporation's utilities.

Although Fortis considers the regulatory frameworks in most of the jurisdictions it operates in to be fair and balanced, uncertainties do exist at the present time. The June 2008 regulatory decision on Belize Electricity's 2008/2009 rate application and changes in electricity legislation made by the Government of Belize and the PUC create uncertainty in the regulatory regime and the rate-setting process in Belize and violate both established regulatory practice and contractual obligations made by the Government of Belize at the time Fortis made its initial investment in Belize Electricity.

Regulatory frameworks in Alberta and Ontario have undergone significant changes since the deregulation of electricity generation and the introduction of retail competition. The regulations and market rules in these jurisdictions, which govern the competitive wholesale and retail electricity markets, are relatively new and there may be significant changes in these regulations and market rules that could adversely affect the ability of FortisAlberta and FortisOntario to recover costs or earn reasonable returns on capital. As these companies and their applicable regulators work through the regulatory processes, it is expected that there will be more certainty in evolving regulatory frameworks and environments.

Although all of the Corporation's regulated utilities currently operate under traditional cost of service and/or rate of return on rate base methodologies, PBR and other rate-setting mechanisms, such as automatic rate of return formulas, are also being employed to varying degrees. A discussion of the impacts of interest rates on allowed ROEs is provided in the "Risk Factors – Interest Rate Risk" section of this 2008 Annual Information Form.

TGI, TGVI and FortisBC are regulated by the BCUC and are subject to approved PBR mechanisms. The PBR mechanisms at TGI and TGVI expire in 2009. In December 2008, the PBR mechanism at FortisBC was extended for the periods from 2009 to 2011 under terms similar to the previous PBR agreement, except annual gross operating and maintenance expenses, before capitalized overhead, will be set by a different formula. The PBR mechanisms provide the utilities an opportunity to earn returns in excess of the allowed ROEs determined by the BCUC. Upon expiry of the PBR mechanisms, there is no certainty as to whether new PBR mechanisms will be entered into or what the particular terms of any renewed PBR mechanisms will be. For further information on FortisBC's PBR mechanism, refer to "Material Regulatory Decisions and Applications" in section 4.0, "Regulation", of this 2008 Annual Information Form.

Operating and Maintenance Risks: The Terasen Gas companies are exposed to various operational risks, such as pipeline leaks; accidental damage to, or fatigue cracks in mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks; and any other accidents involving natural gas which could result in significant operational and/or environmental liability. The business of electricity transmission and distribution is also subject to operational risks including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. The infrastructure of the subsidiaries is also exposed to the effects of severe weather conditions and other acts of nature. In addition, a significant portion of the infrastructure is located in remote areas, which may make access difficult for repair of damage due to weather conditions and other acts of nature. The Terasen Gas companies and FortisBC operate facilities in a terrain with a risk of loss or damage from earthquakes, forest fires, floods, washouts, landslides, avalanches and similar acts of nature. The Corporation and its subsidiaries have insurance that provides coverage for business interruption, liability and property damage, although the coverage offered by this insurance is limited. In the event of a large uninsured loss caused by severe weather conditions or other natural disasters, application will be made to the respective regulatory authority for the recovery of these costs through higher rates to offset any loss. However, there can be no assurance that the regulatory authorities would approve any such application in whole or in part. See the "Risks Factors – Insurance Coverage Risk" section of this 2008 Annual Information Form for a further discussion on insurance.

The Corporation's gas and electricity systems require ongoing maintenance, improvement and replacement. Accordingly, to ensure the continued performance of the physical assets, the utilities determine expenditures that must be made to maintain and replace the assets. If the systems are not able to be maintained, service disruptions and increased costs may be experienced. The inability to obtain regulatory approval to reflect in rates the expenditures the utilities believe are necessary to maintain, improve and replace their assets; the failure by the utilities to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures, despite maintenance programs, could have a material effect on the operations of the utilities.

The Corporation's utilities continually develop capital expenditure programs and assess current and future operating and maintenance expenses that will be incurred in the ongoing operation of their gas and electricity systems. 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 regulator-approved capital expenditures, it is uncertain as to whether any 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 utilities.

Economic Conditions: Typical of utilities, economic conditions in the Corporation's service territories influence energy sales. Energy sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices and housing starts. Also, in the service territories in which the Terasen Gas companies operate, the growth of new multi-family housing starts is continuing to outpace that of new single-family housing starts. Natural gas has a lower penetration rate in multi-family housing; therefore, gas distribution volumes may not grow as quickly as in the past. In the Caribbean, the level of and fluctuations in tourism and related activities, which are closely tied to economic conditions, influence electricity sales as they affect electricity demand of the large hotels and condominium complexes that are serviced by the Corporation's regulated utilities in that region.

Higher energy prices can result in reduced consumption by customers. Natural gas and crude oil exploration and production activity in certain of the Corporation's service territories are closely correlated with natural gas and crude oil prices. The level of these activities can influence energy demand.

An extended decline in economic conditions would be expected to have the effect of reducing demand for energy over time. The regulated nature of utility operations, including various mitigating measures approved by regulators, helps to reduce the impact that lower energy demand, associated with poor economic conditions, may have on the utilities' earnings. However, a severe and prolonged downturn in economic conditions could materially affect the utilities, despite regulatory measures available for compensating for reduced demand. For instance, significantly reduced energy demand in the Corporation's service territories could reduce capital spending which would, in turn, impact rate base and earnings' growth.

In addition to the impact of reduced energy demand, an extended decline in economic conditions could also impair the ability of customers to pay for gas and electricity consumed, thereby affecting the aging and collection of the utilities' trade receivables.

Fortis also holds investments in both commercial real estate and hotel properties. The hotel properties, in particular, are subject to operating risks associated with industry fluctuations and local economic conditions. Fortis Properties' real estate exposure to lease expiries averages approximately 11 per cent per annum over the next five years. Approximately 57 per cent of Fortis Properties' operating income was derived from hotel investments in 2008 (2007 - 58 per cent). Achieving organic revenue and earnings' growth at the Hospitality Division may prove challenging in 2009 as a result of the anticipated continued downturn in the global economy and its overall impact on leisure and business travel and hotel stays. It is estimated that a 10 per cent decrease in revenue at the Hospitality Division would decrease annual basic earnings per common share of Fortis by approximately 2 cents.

Capital Resources and Liquidity Risk: The Corporation's financial position could be adversely affected if it, or its subsidiaries, 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 the financial position of the Corporation and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions. 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, as well as all anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to fund capital expenditures and to repay existing debt.

Generally, the Corporation and its currently rated regulated utilities are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings affect the level of credit risk spreads on new long-term debt issues and on the Corporation's and its utilities' credit facilities. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease the finance charges of the Corporation and its utilities. Also, a significant downgrade in TGI or Terasen Inc.'s credit ratings could trigger margin calls and other cash requirements under TGI's natural gas purchase and natural gas derivative contracts. The Corporation's corporate investment-grade credit ratings were confirmed and maintained during the fourth quarter of 2008. Fortis and its regulated utilities do not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, the current global financial crisis has placed increased scrutiny on rating agencies and rating agency criteria which may result in changes to credit rating practices and policies.

The 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 and its utilities in 2009. While the cost of borrowing is expected to increase, as new long-term debt is expected to be issued at higher rates due to an increase in credit spreads, the Corporation and its utilities expect to continue to have reasonable access to capital in the near to medium terms. Due to the regulated nature of the Corporation's utilities, increased borrowing costs are eligible to be recovered in future customer rates.

To help mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements. The committed credit facility at the Corporation is available for interim financing of acquisitions and for general corporate purposes. The cost of renewed and extended credit facilities may also increase going forward; however, any increased interest expense and/or fees are not expected to have a material financial impact on the Corporation and its utilities in 2009 as the majority of the total committed credit facilities have maturities beyond 2009.

Weather and Seasonality: The physical assets of the Corporation and its subsidiaries are exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed and are operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. At Newfoundland Power, exposure to climatic factors is addressed through the operation of a regulator-approved weather normalization reserve. The operation of this reserve mitigates year-to-year volatility in earnings that would otherwise be caused by variations in weather conditions. At TGI, a BCUC-approved rate stabilization account serves to mitigate the effect on earnings of volume volatility, caused principally by weather, by allowing TGI to accumulate the margin impact of variations in the actual-versus-forecast gas volumes consumed by customers.

At the Terasen Gas companies, weather has a significant impact on distribution volume, as a major portion of the gas distributed is ultimately used for space heating for residential customers. Because of gas-consumption patterns, the Terasen Gas companies normally generate quarterly earnings that vary by season and may not be an indicator of annual earnings. Virtually all of the annual earnings of the Terasen Gas companies are generated in the first and fourth quarters.

Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather. In Canada, cool summers may reduce air conditioning demand while warm winters may reduce electric heating load. In the Caribbean, the impact of seasonal changes in weather on air conditioning demand is less pronounced due to less variable climatic conditions that exist in the region. Significant fluctuations in weather-related demand for electricity could materially impact the operations, financial condition and results of operations of the electric utilities.

Despite preparation for severe weather, extraordinary conditions such as hurricanes and other natural disasters will always remain a risk to utilities. The Corporation uses a centralized insurance management function to create a higher level of insurance expertise and reduce its liability exposure.

The assets and earnings of Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos are subject to hurricane risk. Similar to other Fortis utilities, these companies manage weather risks through insurance on generation assets, business-interruption insurance and self-insurance on transmission and distribution assets. In Belize, additional costs in the event of a hurricane would be deferred and

Belize Electricity may apply for future recovery in customer rates. Under its new transmission and distribution licence, Caribbean Utilities may apply for a special additional customer rate in the event of a disaster, including a hurricane. Fortis Turks and Caicos does not have a specific hurricane cost recovery mechanism; however, the Company may apply for an increase in customer rates in the following year if the actual ROA is lower than the allowed ROA due to additional costs resulting from a hurricane or other significant event.

Earnings from non-regulated generation assets are sensitive to rainfall levels but the geographic diversity of the Corporation's generation assets mitigates the risk associated with rainfall levels.

Commodity Price Risk: The Terasen Gas companies are exposed to commodity price risk associated with changes in the market price of natural gas. The companies employ a number of tools to reduce exposure to natural gas price volatility. These tools include purchasing gas for storage and adopting hedging strategies to reduce price volatility and ensure, to the extent possible, that natural gas commodity costs remain competitive with electricity rates. The use of natural gas derivatives effectively fixes the price of natural gas purchases. Activities related to the hedging of gas prices are currently approved by the BCUC and gains or losses effectively accrue entirely to customers. The operation of BCUC-approved rate stabilization accounts, to flow through in customer rates the commodity cost of natural gas, serves to mitigate the effect on earnings of natural gas cost volatility.

Most of the Corporation's regulated electric utilities are exposed to commodity price risk associated with changes in world oil prices, which affects the cost of fuel and purchased power. The risk is substantially mitigated through the utilities' ability to flow through to customers the cost of fuel and purchased power through basic rates and/or through the use of rate-stabilization and other mechanisms, as approved by the various regulatory authorities. The ability to flow through to customers the cost of fuel and purchased power alleviates the effect on earnings of the variability in the cost of fuel and purchased power.

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of the cost of natural gas, fuel and purchased power will continue to exist in the future. An inability of the regulated utilities to flow through the full cost of natural gas, fuel and/or purchased power could materially affect the utilities' results of operations, financial position and cash flows.

Derivative Financial Instruments and Hedging: From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas commodity prices through the use of derivative financial instruments. The derivative financial instruments, such as interest rate swap contracts, foreign exchange future contracts and natural gas commodity swaps and options, are used by the Corporation and its subsidiaries only to manage risk. The Corporation and its subsidiaries do not hold or issue derivative financial instruments for trading purposes. All derivative financial instruments must be measured at fair value. If a derivative financial instrument is designated as a hedging item in a qualifying cash flow hedging relationship, the effective portion of changes in fair value is recorded in other comprehensive income. Any change in fair value relating to the ineffective portion is recorded immediately in earnings. At the Terasen Gas companies, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a qualifying hedging relationship, and the amount recovered from customers in current rates is subject to regulatory deferral treatment to be recovered from, or refunded to, customers in future rates.

The Corporation's earnings from, and net investment in, its self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars or a currency pegged to the US dollar. Belize Electricity's reporting currency is the Belizean dollar, while the reporting currency of Caribbean Utilities, FortisUS Energy, BECOL, and Fortis Turks and Caicos is the US dollar. The Corporation has also designated all of its US$403 million corporately held US dollar-denominated long-term debt as a hedge of a portion of the Corporation's foreign net investments. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately held US dollar borrowings designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which are also recorded in other comprehensive income. As at December 31, 2008, the Corporation had approximately US$119 million in foreign net investments remaining to be hedged.

Interest Rate Risk: Generally, allowed returns for regulated utilities in North America are exposed to changes in the general level of long-term interest rates. Earnings of such regulated utilities are exposed to changes in long-term interest rates associated with rate-setting mechanisms. The rate of return is affected either directly through automatic adjustment mechanisms or indirectly through regulatory determinations of what constitutes an appropriate rate of return on investment. Automatic adjustment mechanisms currently apply to the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power. Due to a decline in long-term Canada bond yields during 2008 and the operation of the automatic adjustment mechanisms, the allowed ROEs for TGI and FortisBC have been reset for 2009. The 2008 allowed ROEs for the Corporation's four largest utilities, TGI, FortisAlberta, FortisBC and Newfoundland Power, were 8.62 per cent, 8.75 per cent, 9.02 per cent and 8.95 per cent, respectively. Effective January 1, 2009, the allowed ROEs for TGI and FortisBC have decreased to 8.47 per cent and 8.87 per cent, respectively, while the allowed ROE for Newfoundland Power remains unchanged at 8.95 per cent. FortisAlberta is currently engaged in a Generic Cost of Capital Proceeding with its regulator to review, among other things, 2009 ROE calculations and capital structures for regulated gas, electric and pipeline utilities in Alberta. In the interim, as directed by its regulator, customer rates for 2009 for FortisAlberta have been set using the utility's 2007 allowed ROE of 8.51 per cent. The National Energy Board is also undertaking a review of existing ROE levels.

A continuation of current ROE adjustment mechanisms, combined with declining long-term Canada bond yields in an environment where the cost of capital is increasing, could materially affect the ability of the Corporation's utilities to earn reasonable ROEs, the absence of which could negatively impact the regulated utilities' financial condition, results of operations and cash flows.

The Corporation and its subsidiaries are also exposed to interest rate risk associated with short-term borrowings and floating rate debt. However, the Terasen Gas companies and FortisBC have regulatory approval to defer any increase or decrease in interest expense resulting from fluctuations in interest rates associated with variable rate debt for recovery from, or refund to, customers in future rates. The Corporation and its subsidiaries may also enter into interest rate swap agreements from time to time to help reduce interest rate risk.

As at December 31, 2008, approximately 84 per cent of the Corporation's consolidated long-term debt facilities and capital lease obligations had maturities beyond five years. With a significant portion of the Corporation's consolidated debt having long-term maturities, interest rate risk on debt refinancing has been reduced for the near and medium terms.

The following table outlines the nature of the Corporation's consolidated debt at December 31, 2008.

Total Debt as at December 31, 2008		
	($ millions)	(%)
Short-term borrowings	410	7.4
Utilized variable-rate credit facilities classified as long-term	224	4.0
Variable-rate long-term debt and capital lease obligations (including current portion)	22	0.4
Fixed-rate long-term debt and capital lease obligations (including current portion)	4,878	88.2
Total	5,534	100.0

A change in the level of interest rates could materially affect the measurement and recording of changes in the fair value of interest rate swaps. The impact of a material change in interest rates on the fair value measurement of the interest rate swaps outstanding as at December 31, 2008 is not expected to materially affect the Corporation's consolidated earnings and comprehensive income due the low notional value of the interest rate swaps and their near-term maturities.

It is estimated that a 6 cent, or 5 per cent, increase (decrease) in the US dollar-to-Canadian dollar exchange rate from the exchange rate of 1.22, as at December 31, 2008, would increase (decrease) basic earnings per common share of Fortis by 1 cent in 2009.

Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar and Belizean dollar earnings' streams, where possible, through future US dollar borrowings and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Counterparty Risk: The Terasen Gas companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments. The Terasen Gas companies are also exposed to significant credit risk on physical off-system sales. The Terasen Gas companies deal with high credit-quality institutions in accordance with established credit approval practices. Due to recent events in the capital markets, including significant government intervention in the banking system, the Terasen Gas companies have further limited the financial counterparties they transact with and have reduced available credit to, or taken additional security from, the physical off-system sales counterparties with which they transact. To date, the Terasen Gas companies have not experienced any counterparty defaults and they do not expect any counterparties to fail to meet their obligations; however, the credit quality of counterparties, as recent events have indicated, can change rapidly.

FortisAlberta is exposed to credit risk associated with sales to retailers. Significantly all of FortisAlberta's distribution-service billings are to a relatively small group of retailers. As required under regulation, FortisAlberta minimizes its credit exposure associated with retailer billings by obtaining from the retailer a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency, or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating. See also the "Risk Factors – Economic Conditions" section of this 2008 Annual Information Form.

Competitiveness of Natural Gas: In recent years, the price of natural gas has been only marginally lower than the comparable price for electricity for residential customers in British Columbia, especially on Vancouver Island. There is no assurance that natural gas will continue to maintain a competitive price advantage in the future. If natural gas pricing becomes uncompetitive with electricity pricing or pricing for alternative energy sources, the ability of the Terasen Gas companies to add new customers could be impaired and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. This may result in higher rates and, in an extreme case, could ultimately lead to an inability to fully recover the cost of service of the Terasen Gas companies in rates charged to customers. The ability of the Terasen Gas companies to add new customers and increase sales volumes could also be affected by lower prices of other competitive energy sources, as some commercial and industrial customers have the ability to switch to an alternative fuel. See also the "Risk Factors – Risks Related to TGVI" and "Risk Factors – Government of British Columbia's Energy Plan" sections of this 2008 Annual Information Form.

Natural Gas Supply: The Terasen Gas companies are dependent on a limited number of pipeline and storage providers, particularly in the Vancouver, Fraser Valley and Vancouver Island service areas where the majority of the natural gas distribution customers of the Terasen Gas companies are located. Regional market prices have been higher from time to time than prices elsewhere in North America, as a result of insufficient seasonal and peak storage and pipeline capacity to serve the increasing demand for natural gas in British Columbia and the US Pacific Northwest. In addition, the Terasen Gas companies are critically dependent on a single-source transmission pipeline. In the event of a prolonged service disruption of the Spectra Pipeline System, residential customers of the Terasen Gas companies could experience outages, thereby affecting revenue and incurring costs to safely relight customers.

Defined Benefit Pension Plan Performance and Funding Requirements: Each of Terasen, FortisAlberta, FortisBC, Newfoundland Power, FortisOntario, Caribbean Utilities and Fortis maintain defined benefit pension plans for certain of their employees; however, only 61 per cent of the above utilities' total employees are members of such plans. The recent volatility in the global financial and capital markets is expected to affect the Corporation's consolidated future defined benefit pension funding requirements. Future pension benefit obligations and related pension expense may also be affected. The Corporation's and subsidiaries' defined benefit pension plans are subject to judgments utilized in the actuarial determination of the accrued pension benefit obligation and related pension expense. The primary assumptions utilized by Management are the expected long-term rate of return on pension plan assets and the discount rate used to value the accrued pension benefit obligation.

There is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future. With the exception of Newfoundland Power and Terasen, the pension plan assets are valued at fair value. At Newfoundland Power and Terasen, the pension plan assets are valued using the market-related value. Market-driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the assumed long-term return on the assets. This may cause material changes in future pension funding requirements from current estimates and material changes in future pension expense.

Market-driven changes impacting the discount rate, which is used to value the accrued pension benefit obligation as at the measurement date of each of the defined benefit pension plans, may result in material changes in future pension funding requirements from current estimates and material changes in future pension expense.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process as it affects the measurement of pension expense, future funding requirements, the accrued benefit asset, accrued benefit liability and benefit obligation.

The above risks are mitigated as any increase or decrease in future pension funding requirements and/or pension expense at the regulated utilities is expected to be recovered from, or refunded to, customers in future rates, subject to forecast risk. At the Terasen Gas companies and FortisBC, however, actual pension expense above or below the forecast pension expense approved for recovery in customer rates for the year is subject to deferral account treatment for recovery from, or refund to, customers in future rates, subject to regulatory approval. Also mitigating the above risks is the fact that the defined benefit pension plans at FortisAlberta and Newfoundland Power are closed to all new employees.

Risks Related to TGVI: TGVI is a franchise under development in the price-competitive service area of Vancouver Island, with a customer base and revenue that is insufficient to meet the Company's current cost of service and to recover revenue deficiencies from prior years. Recovery of accumulated revenue deficiencies from prior years puts gas at a cost disadvantage relative to electricity. To assist with competitive rates during franchise development, the VINGPA provides royalty revenues from the Government of British Columbia, which currently cover approximately 20 per cent of the current cost of service. These revenues are due to expire at the end of 2011, after which time TGVI's customers will be required to absorb the full commodity cost of gas, all other costs of service and the recovery of any remaining accumulated revenue deficiencies. When VINGPA expires in 2011, the remaining amount outstanding under non-interest bearing senior government loans, which is currently treated as a government contribution against rate base, will be required to be fully repaid. As at December 31, 2008, the balance outstanding under these loans was $61 million. As the debt is repaid, the cost of the higher rate base will increase the cost of service and customer rates, making gas less competitive with electricity on Vancouver Island.

Government of British Columbia's Energy Plan: The Government of British Columbia released its Energy Plan in February 2007. The Energy Plan is a progression from the previous plan with a focus on environmental leadership, energy conservation and efficiency, and investing in innovation. The Energy Plan outlines various measures to address the challenges of global warming, including that all electricity produced in British Columbia will be required to have zero net greenhouse gas emissions by 2016. The Energy Plan places a significant responsibility on British Columbians to conserve energy by requiring 50 per cent of British Columbia's incremental resource needs to be achieved through conservation by 2020. The Energy Plan emphasizes efficiency by requiring BC Hydro to eliminate electricity imports and become fully self-sufficient by 2016. The Energy Plan also states that 90 per cent of British Columbia's electricity will come from renewable sources and British Columbia will become the first jurisdiction in North America to require 100 per cent carbon sequestration for any coal-fired electricity project. FortisBC and the Terasen Gas companies continue to assess the impacts and opportunities provided by the Energy Plan and will consider which policy actions they may support. Many of the principles of the Energy Plan were adopted when *Bill 15-2008, the Utilities Commission Amendment Act, 2008*, received Royal Assent by the Legislative Assembly of British Columbia on May 1, 2008. In addition, the *Carbon Tax Act*, which received Royal Assent by the Legislative Assembly of British Columbia on May 29, 2008, introduced a consumption tax on carbon-based fuels which impacts the competitiveness of natural gas versus non-carbon-based energy sources. The legislation did not, however, introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. The future impact of the Government of British Columbia's Energy Plan and the recent legislation may have a material impact on the competitiveness of natural gas relative to other energy sources.

Environmental Risks: The Corporation and its subsidiaries are subject to numerous laws, regulations and guidelines governing the generation, management, storage, transportation, recycling and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment. Environmental damage and associated costs could potentially arise due to a variety of events, including the impact of severe weather and natural disasters on facilities and equipment and equipment failure. Costs arising from environmental protection initiatives, compliance with environmental laws, regulations and guidelines, or damages may become material to the Corporation and its subsidiaries. In addition, the process of obtaining environmental regulatory approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. During 2008, costs arising from environmental protection, compliance or damages were not material to the Corporation's consolidated results of operations, cash flows or financial position. The Corporation believes that it and its subsidiaries are materially compliant with environmental laws, regulations and guidelines applicable to them in the various jurisdictions in which they operate.

As at December 31, 2008, there were no material environmental liabilities recorded in the Corporation's 2008 consolidated financial statements and there were no material unrecorded environmental liabilities known to Management. The regulated utilities would seek to recover in customer rates the costs associated with environmental protection, compliance or damages; however, there is no assurance that the regulators will agree with the utilities' requests and, therefore, unrecovered costs, if substantial, could materially affect the results of operations, cash flows and financial position of the utilities.

From time to time, it is possible that the Corporation and its subsidiaries may become subject to government orders, investigations, inquiries or other proceedings relating to environmental matters. The occurrence of any of these events, or any changes in applicable environmental laws, regulations and guidelines or their enforcement or regulatory interpretation, could materially impact the results of operations, cash flows and financial position of the Corporation and its subsidiaries.

The Corporation's gas and electricity businesses are subject to inherent risks, including risk of fires and contamination of air, soil or water from hazardous substances. Risks associated with fire damage relate to the extent of forest and grassland cover, habitation and third-party facilities located on or near the land on which the utilities' facilities are situated. The utilities may become liable for fire-suppression costs, regeneration and timber value costs and third-party claims in connection with fires on lands on which its facilities are located if it is found that such facilities were the cause of a fire, and such claims, if successful, could be material. Risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to the storage and handling of large volumes of fuel, the use and disposal of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity. The risk of contamination of air, soil or water at the natural gas utilities primarily relates to natural gas and propane leaks and other accidents involving these substances. The management of greenhouse gas emissions is the main environmental concern of the Corporation's regulated gas utilities, primarily due to recent changes to the Government of British Columbia's Energy Plan and related legislation as discussed above. Any changes in environmental laws, regulations or guidelines governing contamination could lead to significant increases in costs to the Corporation and its subsidiaries.

The key environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purpose of electricity generation.

Scientists and public health experts in Canada, the United States and other countries are studying the possibility that exposure to electric and magnetic fields from power lines, household appliances and other electricity sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health hazard, litigation could result and the electric utilities could be required to pay damages and take mitigation measures on its facilities. The costs of litigation, damages awarded and mitigation measures, if not approved by regulators for recovery in customer rates, could materially impact the results of operations, cash flows and financial condition of the electric utilities.

While the Corporation and its subsidiaries maintain insurance, there can be no assurance that all possible types of liabilities that may arise related to environmental matters will be covered by the insurance. For further information on insurance, refer to the "Risks Factors – Insurance Coverage Risk" section of this 2008 Annual Information Form.

The Corporation's utilities address environmental matters in their operations through the use of environmental management systems. As part of their respective environmental management systems, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor environmental performance.

Insurance Coverage Risk: While the Corporation and its subsidiaries maintain insurance, a significant portion of the Corporation's regulated electric utilities' transmission and distribution assets are not covered under insurance, as is customary in North America, as the cost of the coverage is not considered economical. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions, and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its subsidiaries will be covered by insurance. The Corporation's regulated utilities would likely apply to their respective regulatory authorities to recover the loss or liability through increased customer rates. However, there can be no assurance that regulatory authorities would approve any such application in whole or in part. Any major damage to the physical assets of the Corporation and its subsidiaries could result in repair costs and customer claims that are substantial in amount and which could have an adverse effect on the Corporation's and subsidiaries' business, results of operations and financial condition. In addition, the occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by the Corporation and its subsidiaries, or claims that fall within a significant self-insured retention could have a material adverse effect on the Corporation's and subsidiaries' business, results of operations and financial position.

It is anticipated that such insurance coverage will be maintained. However, there can be no assurance that the Corporation and its subsidiaries will be able to obtain or maintain adequate insurance in the future at rates considered reasonable or that insurance will continue to be available on terms as favourable as the existing arrangements or that the insurance companies will meet their obligations to pay claims.

Licences and Permits: The acquisition, ownership and operation of gas and electric utilities and assets require numerous licences, permits, approvals and certificates from various levels of government and government agencies. The Corporation's regulated utilities and non-regulated generation operations 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 there is a failure to obtain or maintain any required approval or to comply with any applicable law, regulation or condition of an approval, the operation of the assets and the sale of gas and electricity could be prevented or become subject to additional costs, any of which could materially affect the subsidiaries.

Loss of Service Area: FortisAlberta serves customers residing within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta that are located within their municipal boundaries. Upon the termination of its franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government A*ct (Alberta). Under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric utility expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides for compensation, including payment for FortisAlberta's assets on the basis of replacement cost less depreciation. Given the historical growth of Alberta and its municipalities, FortisAlberta may be affected by transactions of this type.

The consequence to FortisAlberta of a municipality purchasing its distribution assets would be an erosion of the Company's rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. No transactions are currently in progress with FortisAlberta pursuant to the *Municipal Government Act* (Alberta). However, upon expiration of franchise agreements, there is a risk that municipalities will opt to purchase the distribution assets existing within their boundaries, the loss of which could materially affect the financial condition and results of operations of FortisAlberta.

Market Energy Sales Prices: The Corporation's primary exposure to changes in market energy sales prices at its electricity operations has related to its non-regulated energy sales in Ontario, where energy is sold to the Independent Electricity System Operator at market prices. Non-regulated energy sales in Ontario largely relate to a power-for-water exchange agreement, known as the Niagara Exchange Agreement, associated with the Rankine hydroelectric generating station. In accordance with this agreement, FortisOntario's water entitlement on the Niagara River will expire on April 30, 2009 and, as a result, the Corporation's exposure to market price fluctuations in Ontario will be substantially reduced and earnings related to the Niagara Exchange Agreement will cease after that date. During 2008, earnings' contribution associated with the Niagara Exchange Agreement was approximately $16 million. The Corporation is also exposed to changes in energy prices related to energy sales from its non-regulated generation assets in Upper New York State. All energy produced by these assets is sold to the National Grid at market prices. Energy from the Corporation's non-regulated generation assets in Belize, central Newfoundland and British Columbia is sold under medium- and long-term fixed-price contracts.

Transition to IFRS: Effective January 1, 2011, Canadian publicly accountable enterprises are required to adopt IFRS as issued by the International Accounting Standards Board. IFRS will require increased financial statement disclosure compared to Canadian GAAP and accounting policy differences between Canadian GAAP and IFRS will need to be addressed by Fortis. The Corporation is currently assessing the impact a conversion to IFRS would have on its future financial reporting. In the event regulated assets and liabilities are not permissible under IFRS, this could result in increased volatility in the Corporation's consolidated earnings and balance sheet from that reported under Canadian GAAP.

Changes in Tax Legislation: The Government of Canada has enacted legislative changes that will challenge the continuation of the tax-deferred status of offshore earnings derived from foreign affiliates. The legislative changes will require that the governments of these tax-free jurisdictions enter into tax treaties or other comprehensive TIEAs with Canada before 2015. If the jurisdictions are unable to establish these treaties or agreements, the earnings of Canadian subsidiaries operating in these jurisdictions will be taxed on an accrual basis after 2014 as if they were in Canada. Conversely, if treaties or agreements can be reached, the earnings from these jurisdictions will be able to be repatriated to Canada tax free. In the event that the offshore earnings become taxable, earnings' contribution from the Corporation's Caribbean Regulated Electric utilities and BECOL will decrease.

On December 10, 2008, the Advisory Panel provided its recommendations to the Minister of Finance of the Government of Canada in its final report, "Enhancing Canada's International Tax Advantage". The Advisory Panel was formed by the Government of Canada in November 2007 to provide recommendations to improve Canada's international tax policy respecting foreign investment by Canadian businesses and investment in Canada by foreign businesses. The Advisory Panel's recommendations seek to improve Canada's tax system regarding outbound and inbound business investment, non-resident withholding taxes, and administration, compliance and legislative processes. Specifically, the Advisory Panel recommended that the Government of Canada pursue TIEAs on a government-to-government basis without resorting to accrual taxation for foreign active business income if a TIEA is not obtained. The Advisory Panel also recommended that the Government of Canada broaden the existing exemption system to cover all foreign active business income earned by foreign affiliates.

On January 27, 2009, the Government of Canada introduced its 2009 Budget. In the budget documents, the Government of Canada indicated that it is studying the Advisory Panel's report and will provide a response in due course on which consultations will be held. The Government of Canada also indicated that it will consider the Advisory Panel's recommendations relating to foreign affiliates before proceeding with the remaining foreign affiliate measures announced in February 2004, as modified to take into account consultations and deliberations since their release.

Any future changes in other tax legislation could also materially affect the Corporation's consolidated earnings.

First Nations' Lands: The Terasen Gas companies and FortisBC provide service to customers on First Nations' lands and maintain gas and electric distribution facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the Government of British Columbia is underway, but the basis upon which settlements might be reached in the service areas of the Terasen Gas companies and FortisBC is not clear. Furthermore, not all First Nations 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 Terasen Gas companies and FortisBC. However, there can be no certainty that the settlement process will not materially affect the business of the Terasen Gas companies and FortisBC. In addition, FortisAlberta has distribution assets on First Nations' lands with access permits to these lands held by FortisAlberta's predecessor, TransAlta Utilities Corporation. In order for FortisAlberta to acquire these access permits, both the Department of Indian and Northern Affairs Canada and the individual Band councils must grant approval. FortisAlberta may not be able to acquire the access permits from TransAlta Utilities Corporation and may not be able to negotiate land-usage agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to FortisAlberta and, therefore, may have a material effect on the business of FortisAlberta.

Labour Relations: Approximately 60 per cent of the employees of the Corporation's subsidiaries are members of labour unions or associations which have entered into collective bargaining agreements with the subsidiaries. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the businesses carried out by the subsidiaries. The Corporation considers the relationships of its subsidiaries with its labour unions and associations 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 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 rate orders at the regulated utilities and which could have a material effect on the results of operations, cash flow and earnings of the utilities.

Human Resources: The ability of Fortis to deliver superior operating performance in a cost-effective manner is dependent on the ability of the Corporation's subsidiaries to attract, develop and retain skilled workforces. Like other utilities across Canada and the Caribbean, the Corporation's utilities are faced with demographic challenges relating to trades, technical staff and engineers. The growing size of the Corporation and an increasingly competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program over the next several years will present challenges in ensuring the Corporation's utilities have the qualified workforce necessary to complete the capital work initiatives.

7.0 GENERAL DESCRIPTION OF SHARE CAPITAL STRUCTURE

The authorized share capital of the Corporation consists of the following:

(a) an unlimited number of Common Shares without nominal or par value;
(b) an unlimited number of First Preference Shares without nominal or par value; and
(c) an unlimited number of Second Preference Shares without nominal or par value.

At March 12, 2009, the following Common Shares and First Preference Shares were issued and outstanding.

Share Capital	Issued and Outstanding	Votes per Share
Common Shares	169,758,654	One
First Preference Shares, Series C	5,000,000	None
First Preference Shares, Series E	7,993,500	None
First Preference Shares, Series F	5,000,000	None
First Preference Shares, Series G	9,200,000	None

The following table summarizes the cash dividends declared per share for each of the Corporation's class of share for the past three years.

	Dividends Declared *(per share)*		
Share Capital	**2006**	**2007**	**2008**
Common Shares	$0.70	$0.88	$1.01
First Preference Shares, Series C	$1.3625	$1.3625	$1.3625
First Preference Shares, Series E	$1.2250	$1.2250	$1.2250
First Preference Shares, Series F [(1)]	$0.5211	$1.2250	$1.2250
First Preference Shares, Series G [(2)]	-	-	$1.0184

[(1)] The First Preference Shares, Series F were issued in September 2006.
[(2)] The First Preference Shares, Series G were issued in May and June 2008.

For purposes of the enhanced dividend tax credit rules contained in the Income Tax Act (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on Common and Preferred Shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends." Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

On December 10, 2008, the Board declared an increase in the regular quarterly dividend to $0.26 per Common Share, with the first payment occurring on March 1, 2009, which was paid to holders of record on February 6, 2009. Also on December 10, 2008, the Board declared a first quarter 2009 dividend on the First Preference Shares, Series C, E, F and G in accordance with the applicable annual prescribed rate and was paid to holders of record on February 6, 2009.

On March 11, 2009, the Board declared a second quarter 2009 dividend of $0.26 per Common Share and a second quarter 2009 dividend on the First Preference Shares, Series C, E, F and G in accordance with the applicable annual prescribed rate. In each case, the second quarter 2009 dividends will be paid on June 1, 2009 to holders of record on May 8, 2009.

Common Shares

Dividends on Common Shares are declared at the discretion of the Board. Holders of Common Shares are entitled to dividends on a pro rata basis if, as, and when declared by the Board. Subject to the rights of the holders of the First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive dividends in priority to or rateably with the holders of the Common Shares, the Board may declare dividends on the Common Shares to the exclusion of any other class of shares of the Corporation.

On the liquidation, dissolution or winding-up of Fortis, holders of Common Shares are entitled to participate rateably in any distribution of assets of Fortis, subject to the rights of holders of First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or rateably with the holders of the Common Shares.

Holders of the Common Shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Fortis, other than separate meetings of holders of any other class or series of shares, and are entitled to one vote in respect of each Common Share held at such meetings.

First Preference Shares, Series C

The 5,000,000 First Preference Shares, Series C are entitled to fixed cumulative preferential cash dividends at a rate of $1.3625 per share per annum. On or after June 1, 2010, the Corporation may, at its option, redeem for cash the First Preference Shares, Series C, in whole at any time, or in part from time to time, at $25.75 per share if redeemed before June 1, 2011; at $25.50 per share if redeemed on or after June 1, 2011 but before June 1, 2012; at $25.25 per share if redeemed on or after June 1, 2012 but before June 1, 2013; and at $25.00 per share if redeemed on or after June 1, 2013 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. On or after June 1, 2010, the Corporation may, at its option, convert all, or from time to time, any part of the outstanding First Preference Shares, Series C into fully paid and freely tradable Common Shares of the Corporation. The number of Common Shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per Preference Share, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95 per cent of the then-current market price of the Common Shares. On or after September 1, 2013, each First Preference Share, Series C will be convertible at the option of the holder on the first day of September, December, March and June of each year into freely tradable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95 per cent of the then-current market price of the Common Shares. If a holder of First Preference Shares, Series C elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference Shares, Series C for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series E

The 7,993,500 First Preference Shares, Series E are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. On or after June 1, 2013, the Corporation may, at its option, redeem all, or from time to time any part of, the outstanding First Preference Shares, Series E by the payment in cash of a sum per redeemed share equal to $25.75 if redeemed during the 12 months commencing June 1, 2013; $25.50 if redeemed during the 12 months commencing June 1, 2014; $25.25 if redeemed during the 12 months commencing June 1, 2015; and $25.00 if redeemed on or after June 1, 2016 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. On or after June 1, 2013, the Corporation may, at its option, convert all, or from time to time any part of the outstanding First Preference Shares, Series E into fully paid and freely tradable Common Shares of the Corporation. The number of Common Shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per First Preference Share, Series E, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95 per cent of the then-current market price of the Common Shares at such time. On or after September 1, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first business day of September, December, March and June of each year, into fully paid and freely tradable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95 per cent of the then-current market price of the Common Shares. If a holder of First Preference Shares, Series E elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference, Shares E for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series F

The 5,000,000 First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. On or after December 1, 2011, the Corporation may, at its option, redeem for cash the First Preference Shares, Series F, in whole at any time or in part from time to time, at $26.00 per share if redeemed before December 1, 2012, at $25.75 per share if redeemed on or after December 1, 2012 but before December 1, 2013, at $25.50 per share if redeemed on or after December 1, 2013 but before December 1, 2014, at $25.25 per share if redeemed on or after December 1, 2014 but before December 1, 2015, and at $25.00 per share if redeemed on or after December 1, 2015 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series G

The 9,200,000 First Preference Shares, Series G are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.3125 per share per annum for each year up to and including August 31, 2013. For each five-year period after that date, the holders of First Preference Shares, Series G are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying the $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13 per cent. On September 1, 2013, and on September 1 every five years thereafter, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series G, in whole at any time, or in part from time to time, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

Convertible Debentures

The Corporation’s US$40 million 5.50% Unsecured Subordinated Convertible Debentures, due 2016, are redeemable by the Corporation at par at any time on or after November 7, 2011 and are convertible, at the option of the holder, into the Corporation’s Common Shares at US$29.11 per share. The debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the debentures. There is no provision associated with these debentures that restricts the payment of dividends.

Debt Covenant Restrictions on Dividend Distributions

The Trust Indenture pertaining to the Corporation's $100 million Senior Unsecured Debentures contains a covenant which provides that Fortis shall not declare or pay any dividends (other than stock dividends or cumulative preferred dividends on preferred shares not issued as stock dividends) or make any other distribution on its shares if, immediately thereafter, its consolidated funded obligations would be in excess of 75 per cent of its total consolidated capitalization.

The Corporation has a $600 million unsecured committed credit facility, maturing in May 2012, that can be used for general corporate purposes, including acquisitions. The credit facility contains a covenant which provides that Fortis shall not declare or pay any dividends or make any other restricted payments if, immediately thereafter, consolidated debt to consolidated capitalization ratio would exceed 70 per cent at any time.

8.0 CREDIT RATINGS

Securities issued by Fortis and its currently rated utilities are rated by one or more credit rating agencies, namely, DBRS, S&P and/or Moody's. The ratings assigned to securities issued by Fortis and its currently rated utilities are reviewed by the agencies on an ongoing basis. Credit ratings and stability ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are not recommendations to buy, sell or hold securities. Ratings may be subject to revision or withdrawal at any time by the rating organization. The following table summarizes the Corporation's credit ratings as at March 12, 2009.

Fortis
Credit Ratings

Company	DBRS	S&P	Moody's
Fortis	BBB (high), stable (unsecured debt)	A-, stable (unsecured debt)	N/A
Terasen	BBB (high), stable (unsecured debt)	BBB+, stable [(1)] (unsecured debt)	Baa 2, stable (unsecured debt)
TGI	A, stable (secured & unsecured debt)	A, stable [(1)] (unsecured debt)	A3, stable (unsecured debt)
TGVI	BBB (high), stable (unsecured debt)	N/A	A3, stable (unsecured debt)
FortisAlberta	A (low), stable (senior unsecured debt)	A-, stable (senior unsecured debt)	Baa 1, stable (senior unsecured debt)
FortisBC	BBB (high), stable (secured & unsecured debt)	N/A	Baa 2, stable (unsecured debt)
Newfoundland Power	A, stable (first mortgage bonds)	N/A	Baa 1, stable (first mortgage bonds)
Maritime Electric	N/A	A, stable (senior secured debt)	N/A
Caribbean Utilities	A (low), stable (senior unsecured debt)	A, stable (senior unsecured debt)	N/A

[(1)] Unsolicited

DBRS rates debt instruments by rating categories ranging from AAA to D, which represents the range from highest to lowest quality of such securities. DBRS states that: (a) 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; (b) its 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; and (c) every rating is based on quantitative and qualitative considerations that are relevant for the borrowing entity. According to DBRS, a rating of A by DBRS is in the middle of three subcategories within the third highest of nine major categories. Such rating is assigned to debt instruments considered to be of satisfactory credit quality and for which protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. Entities in the BBB category are considered to have long-term debt 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. The assignment of a (high) or (low) modified within each rating category indicates relative standing within such category.

S&P long-term debt ratings are on a ratings scale that ranges from AAA to C, which represents the range from highest to lowest quality of such securities. S&P uses '+' or '-' designations to indicate the relative standing of securities within a particular rating category. S&P states that its credit ratings are

current opinions of the financial security characteristics with respect to the ability to pay under contracts in accordance with their terms. This opinion is not specific to any particular contract, nor does it address the suitability of a particular contract for a specific purpose or purchaser. An issuer rated A is regarded as having financial security characteristics to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than those in higher-rated categories.

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 states that its long-term debt ratings are opinions of relative risk of fixed-income obligations with an original maturity of one year or more and that 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 and such a debt rating is assigned to debt instruments considered to be of medium-grade quality. Debt instruments rated Baa are subject to moderate credit risk and may possess certain speculative characteristics.

9.0 MARKET FOR SECURITIES

The Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; and First Preference Shares, Series G of Fortis are listed on the Toronto Stock Exchange under the symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F and FTS.PR.G, respectively.

The following table sets forth the reported high and low trading prices and trading volumes for the Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; and First Preference Shares, Series G on a monthly basis for the year ended December 31, 2008.

Fortis
2008 Trading Prices and Volumes

	Common Shares			First Preference Shares, Series C		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
Jan	29.50	26.52	11,699,266	27.39	26.27	23,148
Feb	29.89	27.77	9,436,783	27.39	26.31	20,357
Mar	29.24	26.36	7,245,917	26.50	25.60	28,658
Apr	29.94	26.85	10,311,561	27.75	25.76	18,972
May	28.34	26.80	11,864,145	26.75	25.37	123,787
Jun	28.02	27.05	7,651,899	26.64	25.76	44,426
Jul	27.65	24.11	10,918,974	26.25	25.80	25,580
Aug	27.15	24.51	8,347,786	26.24	25.50	91,043
Sep	26.23	23.50	8,047,826	26.20	25.26	19,704
Oct	26.75	20.70	19,490,343	26.25	20.44	54,921
Nov	28.00	24.51	13,933,581	25.50	23.56	124,621
Dec	27.46	23.15	13,159,441	25.95	24.55	98,670
	First Preference Shares, Series E			**First Preference Shares, Series F**		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
Jan	26.62	25.98	115,209	22.50	21.33	206,795
Feb	26.96	26.49	10,705	23.50	22.00	111,470
Mar	26.89	25.50	43,889	23.20	21.25	103,475
Apr	26.50	25.51	33,454	22.88	21.09	116,137
May	25.97	25.00	330,602	22.40	21.40	86,078
Jun	26.70	24.80	52,730	21.87	19.00	166,441
Jul	26.50	24.50	31,794	20.00	18.00	159,824
Aug	26.49	24.55	39,848	20.35	19.75	100,320
Sep	26.39	24.85	89,850	20.50	18.50	113,705
Oct	24.50	23.00	44,208	18.99	16.57	224,945
Nov	24.99	22.50	28,650	19.78	16.00	100,535
Dec	25.99	21.00	108,907	17.85	15.50	241,520

	First Preference Shares, Series G [(1)]		
Month	**High ($)**	**Low ($)**	**Volume**
May	25.10	24.84	426,990
Jun	25.50	24.95	263,022
Jul	25.52	25.01	124,660
Aug	25.98	25.25	114,417
Sep	25.80	25.10	156,866
Oct	25.45	20.00	70,985
Nov	24.00	18.00	181,916
Dec	22.00	17.00	296,675

[(1)] The First Preference Share, Series G were issued in May and June 2008.

10.0 DIRECTORS AND OFFICERS

The Board adopted a director tenure policy in 1999 which is reviewed on a periodic basis and was most recently affirmed at a meeting of the Board held in September 2007. The tenure policy provides that Directors of the Corporation are to be elected for a term of one year and, except in exceptional circumstances determined by the Board, be eligible for re-election until the Annual Meeting of Shareholders next following the earlier of the date on which they achieve age 70 or the 10th anniversary of their initial election to the Board. This policy became effective prospectively in 1999 and did not apply to Dr. Inkpen's service prior to 1999. The policy does not apply to Mr. Marshall whose service on the Board is related to his tenure as CEO. The following chart sets out the name and municipality of residence of each of the Directors of Fortis and indicates their principal occupations within five preceding years.

Fortis Directors	
Name	**Principal Occupations Within Five Preceding Years**
PETER E. CASE (1) Freelton, Ontario	Mr. Case, 54, a Corporate Director, retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. During his 17-year career as senior investment analyst with CIBC World Markets and BMO Nesbitt Burns and its predecessors, Mr. Case's coverage of Canadian and selected US pipeline and energy utilities was consistently rated among the top rankings. He was awarded a Bachelor of Arts and a Master of Business Administration from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto. Mr. Case was first elected to the Board in May 2005. Mr. Case was appointed to the Board of Directors of FortisOntario Inc. in March 2003 and assumed the Chair of the FortisOntario Inc. Audit Committee in January 2004. Mr. Case does not serve as a director of any other reporting issuer.
FRANK J. CROTHERS Nassau, Bahamas	Mr. Crothers, 64, is Chairman and Chief Executive Officer of Island Corporate Holdings Limited, Nassau, Bahamas. Over the past 35 years, he has served on many public and private sector boards. For over a decade he was on the Board of Harvard University Graduate School of Education and also served a three-year term as Chairman of CARILEC, the Caribbean Association of Electrical Utilities. Mr. Crothers is the former President of P.P.C. Limited, which was acquired by the Corporation on August 28, 2006. Mr. Crothers is the Vice Chair of the Board of Caribbean Utilities and serves on the Board of Belize Electricity Limited. Mr. Crothers was first elected to the Fortis Board in May 2007. He is also a director of reporting issuers Franklin Templeton Resources, Fidelity Merchant Bank & Trust (Cayman) Limited, Talon Metals Corp. and Victory Nickel Inc.
GEOFFREY F. HYLAND (1)(2)(3) Caledon, Ontario	Mr. Hyland, 64, a Corporate Director, retired as President and Chief Executive Officer of ShawCor Ltd. in June 2005 after 37 years of service. He graduated from McGill University with a Bachelor of Engineering (Chemical) and York University with a Master of Business Administration. Mr. Hyland was first elected to the Board in May 2001 and was appointed Chair of the Board in May 2008. Mr. Hyland is a director of FortisOntario Inc. He continues to serve on the board of ShawCor Ltd. and is a director of Enerflex Systems Income Fund, SCITI Total Return Trust and Exco Technologies Limited.
LINDA L. INKPEN (2)(4) St. Philips, Newfoundland and Labrador	Dr. Inkpen, 61, retired from her medical practice in December 2008 after 35 years of service. She has served as a Commissioner of the Royal Commission on Employment and Unemployment, Province of Newfoundland and Labrador and is past President of the College of the North Atlantic. She is past Chair of the Medical Advisory Committee for the St. John's hospitals for Eastern Health, Newfoundland and Labrador. Dr. Inkpen was named a member of the Order of Canada in 1998 and awarded the Queen's Jubilee Medal. She graduated from Memorial University of Newfoundland with a Bachelor of Science, a Bachelor of Education, a Bachelor of Medical Science and a Doctor of Medicine. Dr. Inkpen was first elected to the Board in April 1994. Dr. Inkpen is past Chair of the Boards of Fortis Properties Corporation and Newfoundland Power. She does not serve as a director of any other reporting issuer. Dr. Inkpen will be retiring from the Fortis Board at the Annual Meeting on May 5, 2009.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
H. STANLEY MARSHALL Paradise, Newfoundland and Labrador	Mr. Marshall, 58, is President and Chief Executive Officer of the Corporation. He joined Newfoundland Power in 1979 and was appointed President and Chief Executive Officer of Fortis in 1996. Mr. Marshall graduated from the University of Waterloo with a Bachelor of Applied Science (Chem. Eng.) and Dalhousie University with a Bachelor of Laws. He is a member of the Law Society of Newfoundland and Labrador and a Registered Professional Engineer in the Province of Newfoundland and Labrador. Mr. Marshall was first elected to the Board in October 1995. Mr. Marshall serves on the boards of all Fortis utilities in western Canada and the Caribbean (including Caribbean Utilities) and the Board of Fortis Properties Corporation. He is also a director of Toromont Industries Ltd.
JOHN S. McCALLUM (1)(2) Winnipeg, Manitoba	Mr. McCallum, 65, has been a Professor of Finance at the University of Manitoba since July 1973. He served as Chairman of Manitoba Hydro from 1991 to 2000 and as Policy Advisor to the Federal Minister of Finance from 1984 to 1991. Mr. McCallum graduated from the University of Montreal with a Bachelor of Arts (Economics) and a Bachelor of Science (Mathematics). He was awarded a Master of Business Administration from Queen's University and a PhD in Finance from the University of Toronto. Mr. McCallum was first elected to the Board in July 2001 and was appointed Chair of the Governance and Nominating Committee of the Corporation in May 2005. He is a director of FortisBC Inc. and FortisAlberta Inc. and chairs the Audit, Risk and Environment Committees of both companies. He also serves as a director of IGM Financial Inc., Toromont Industries Ltd. and Wawanesa.
HARRY McWATTERS (2) Summerland, British Columbia	Mr. McWatters, 63, is the founder and past President of Sumac Ridge Estate Wine Group, a leader in the British Columbia Wine industry. He is President of Vintage Consulting Group Inc. and Harry McWatters Inc., Okanagan Wine Academy and Black Sage Vineyards Ltd., all of which are engaged in various aspects of the British Columbia wine industry. Mr. McWatters was first elected to the Board in May 2007. He was elected to the Board of FortisBC Inc. in September 2005 and appointed as Chair of that company's Board in 2006. Mr. McWatters became a director of Terasen Inc. in November 2007 and does not serve as a director of any other reporting issuer.
DAVID G. NORRIS (1)(3) St. John's, Newfoundland and Labrador	Mr. Norris, 61, a Corporate Director, has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited. Previously, he held Deputy Minister positions with the Department of Finance and Treasury Board, Government of Newfoundland and Labrador. Mr. Norris graduated with a Bachelor of Commerce from Memorial University of Newfoundland and a Master of Business Administration from McMaster University. Mr. Norris was first elected to the Board in May 2005 and, in May 2006, he was appointed Chair of the Audit Committee of the Board. He has been a director of Newfoundland Power since 2003 and was appointed Chair of that company's Board in April 2006. Mr. Norris was appointed to the Board of Fortis Properties Corporation in 2006. He does not serve as a director of any other reporting issuer.
MICHAEL A. PAVEY (3) Moncton, New Brunswick	Mr. Pavey, 61, a Corporate Director, retired as Executive Vice-President and Chief Financial Officer of Major Drilling Group International Inc. in September 2006. Prior to joining Major Drilling Group International Inc. in 1999, he held senior executive positions with a major integrated electric utility in western Canada. Mr. Pavey graduated from the University of Waterloo with a Bachelor of Applied Science (Mechanical Engineering) and from McGill University with a Master of Business Administration. He retired from the Board of Maritime Electric in February 2007 after a six-year term, which included three years' service as Chair of that company's Audit and Environment Committee. Mr. Pavey was first elected to the Board in May 2004. Mr. Pavey does not serve as a director of any other reporting issuer.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
ROY P. RIDEOUT [(2)(3)] Halifax, Nova Scotia	Mr. Rideout, 61, a Corporate Director, retired as Chairman and Chief Executive Officer of Clarke Inc. in October 2002. Prior to 1998, he served as President of Newfoundland Capital Corporation Limited and held senior executive positions in the Canadian airline industry. Mr. Rideout graduated with a Bachelor of Commerce from Memorial University of Newfoundland and obtained designation as a Chartered Accountant. Mr. Rideout was first elected to the Board in March 2001. He is the Chair of the Human Resources Committee of the Board and has held that position since May 2003. Mr. Rideout serves as a director of the Halifax International Airport Authority and NAV CANADA.

(1) Serves on the Audit Committee
(2) Serves on the Governance and Nominating Committee
(3) Serves on the Human Resources Committee
(4) Dr. Inkpen will not be standing for re-election as director at the Annual Meeting of Shareholders on May 5, 2009, in accordance with Board policy.

The following table sets out the name and municipality of residence of each of the officers of Fortis and indicates the office held.

Fortis Officers	
Name and Municipality of Residence	**Office Held**
H. Stanley Marshall Paradise, Newfoundland and Labrador	President and Chief Executive Officer [(1)]
Barry V. Perry Mount Pearl, Newfoundland and Labrador	Vice President, Finance and Chief Financial Officer [(2)]
Ronald W. McCabe St. John’s, Newfoundland and Labrador	Vice President, General Counsel and Corporate Secretary [(3)]
Donna G. Hynes St. John’s, Newfoundland and Labrador	Assistant Secretary [(4)]

(1) Mr. Marshall was appointed President and Chief Operating Officer, effective October 1, 1995. Effective May 1, 1996, Mr. Marshall became Chief Executive Officer.
(2) Mr. Perry was appointed Vice President, Finance and Chief Financial Officer, effective January 1, 2004. Prior to that time, Mr. Perry was Vice President, Finance and Chief Financial Officer of Newfoundland Power.
(3) Mr. McCabe was appointed General Counsel and Corporate Secretary, effective January 1, 1997. Effective May 6, 2008, Mr. McCabe became Vice President, General Counsel and Corporate Secretary.
(4) Ms. Hynes was appointed Assistant Secretary, effective December 8, 1999. She joined Fortis as Manager, Investor and Public Relations in October 1999 and, prior to that time, was employed by Newfoundland Power.

As at December 31, 2008, the directors and officers of Fortis, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 682,714 Common Shares, representing 0.4 per cent of the issued and outstanding Common Shares of Fortis. The Common Shares are the only voting securities of the Corporation.

11.0 AUDIT COMMITTEE

11.1 Education and Experience

The education and experience of each Audit Committee Member that is relevant to such Member's responsibilities as a Member of the Audit Committee are set out below. As at December 31, 2008, the Audit Committee was composed of the following persons.

Fortis Audit Committee	
Name	**Relevant Education and Experience**
PETER E. CASE Freelton, Ontario	Mr. Case retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. Mr. Case was awarded a Bachelor of Arts and a Master of Business Administration from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto.
GEOFFREY F. HYLAND Caledon, Ontario	Mr. Hyland retired as President and Chief Executive Officer of ShawCor Ltd. in June 2005 after 37 years of service. Mr. Hyland graduated from McGill University with a Bachelor of Engineering (Chemical) and from York University with a Master of Business Administration.
JOHN S. McCALLUM Winnipeg, Manitoba	Mr. McCallum is a Professor of Finance at the University of Manitoba. Mr. McCallum graduated from the University of Montreal with a Bachelor of Arts (Economics) and a Bachelor of Science (Mathematics). He was awarded a Master of Business Administration from Queen's University and a PhD in Finance from the University of Toronto.
DAVID G. NORRIS *(Chair)* St. John's, Newfoundland and Labrador	Mr. Norris graduated with a Bachelor of Commerce from Memorial University of Newfoundland and a Master of Business Administration from McMaster University. Mr. Norris has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited.

The Board has determined that each of the Audit Committee Members is independent and financially literate. Independent means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110 - Audit Committees. Financially literate means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

11.2 Audit Committee Mandate

The text of the Corporation’s Audit Committee Mandate is detailed below.

Objective

The Audit Committee shall provide assistance to the Board by overseeing the external audit of the Corporation’s annual financial statements and the accounting and financial reporting and disclosure processes and policies of the Corporation.

Definitions

In this mandate:

“AIF” means the Annual Information Form filed by the Corporation;

“Committee” means the Audit Committee appointed by the Board pursuant to this mandate;

“Board” means the board of directors of the Corporation;

“CICA” means the Canadian Institute of Chartered Accountants or any successor body;

“Corporation” means Fortis Inc.;

“**Director”** means a member of the Board;

“Financially Literate” means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be present in the Corporation’s financial statements;

“External Auditor” means the firm of chartered accountants, registered with the Canadian Public Accountability Board or its successor, and appointed by the shareholders of the Corporation to act as External Auditor of the Corporation;

“Independent” means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member’s independent judgment as more particularly described in Multilateral Instrument 52-110;

“Internal Auditor” means the person employed or engaged by the Corporation to perform the internal audit function of the Corporation;

“Management” means the senior officers of the Corporation;

“MD&A” means the Corporation’s management discussion and analysis prepared in accordance with National Instrument 51-102F1 in respect of the Corporation’s annual and interim financial statements; and

“Member” means a Director appointed to the Committee.

Composition and Meetings

1. The Committee shall be appointed annually by the Board and shall be comprised of three (3) or more Directors; each of whom is Independent and Financially Literate and none of whom is a member of Management or an employee of the Corporation or of any affiliate of the Corporation.

2. The Board shall appoint a Chair of the Committee on the recommendation of the Corporation's Governance and Nominating Committee, or such other committee as the Board may authorize.

3. The Committee shall meet at least four (4) times each year and shall meet at such other times during the year as it deems appropriate. Meetings of the Committee shall be held at the call of: (i) the Chair of the Committee, or (ii) any two (2) Members, or (iii) the External Auditor.

4. The President and Chief Executive Officer, the Vice President, Finance and Chief Financial Officer, the External Auditor and the Internal Auditor shall receive notice of, and (unless otherwise determined by the Chair of the Committee) shall attend all meetings of the Committee.

5. A quorum at any meeting of the Committee shall be three (3) Members.

6. The Chair of the Committee shall act as chair of all meetings of the Committee at which the Chair is present. In the absence of the Chair from any meeting of the Committee, the Members present at the meeting shall appoint one of their Members to act as Chair of the meeting.

7. Unless otherwise determined by the Chair of the Committee, the Secretary of the Corporation shall act as secretary of all meetings of the Committee.

Oversight of the External Audit and the Accounting and Financial Reporting and Disclosure Processes and Policies

The primary purpose of the Committee is oversight of the Corporation's external audit and the accounting and financial reporting and disclosure processes and policies on behalf of the Board. Management of the Corporation is responsible for maintaining appropriate accounting and financial reporting principles, policies, internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations. Management is responsible for the preparation and integrity of the financial statements of the Corporation.

1. Oversight of the External Audit

   The oversight of the external audit pertains to the audit of the Corporation's annual financial statements.

   1.1. The Committee is responsible for the evaluation and recommendation of the External Auditor to be proposed by the Board for appointment by the shareholders.

   1.2. In advance of each audit, the Committee shall review the External Auditor's audit plan including the general approach, scope and areas subject to risk of material misstatement.

   1.3. The Committee is responsible for approving the terms of engagement and fees of the External Auditor.

   1.4. The Committee shall review and discuss the Corporation's annual audited financial statements, together with the External Auditor's report thereon, and MD&A with Management and the External Auditor to gain reasonable assurance as to the accuracy, consistency and completeness thereof. The Committee shall meet privately with the External

Auditor. The Committee shall oversee the work of the External Auditor and resolve any disagreements between Management and the External Auditor.

1.5. The Committee shall use reasonable efforts, including discussion with the External Auditor, to satisfy itself as to the External Auditor's independence as defined in the CICA Assurance Handbook Section 5751.

2. Oversight of the Accounting and Financial Reporting and Disclosure Processes

2.1. The Committee shall recommend the annual audited financial statements together with the MD&A for approval by the Board.

2.2. The Committee shall review the interim unaudited financial statements with the External Auditor and Management, together with the External Auditor's review engagement report thereon.

2.3. The Committee shall review and approve publication of the interim unaudited financial statements, together with the interim MD&A and earnings media release on behalf of the Board.

2.4. The Committee shall review and recommend approval by the Board of the Corporation's AIF, Management Information Circular, any prospectus and other financial information or disclosure documents to be issued by the Corporation prior to their public release.

2.5. The Committee shall use reasonable efforts to satisfy itself as to the integrity of the Corporation's financial information systems, internal control over financial reporting and the competence of the Corporation's accounting personnel and senior financial management responsible for accounting and financial reporting.

2.6. The Committee shall be responsible for the oversight of the Internal Auditor.

3. Oversight of the Audit Committee Mandate and Policies

On a periodic basis, the Committee shall review and report to the Board on the Audit Committee Mandate as well as on the following policies:

3.1. Reporting Allegations of Suspected Improper Conduct and Wrongdoing Policy;

3.2. Derivative Financial Instruments and Hedging Policy;

3.3. Pre-Approval of Audit and Non-Audit Services Policy;

3.4. Hiring of Employees from Independent Auditing Firms Policy;

3.5. The Internal Audit Role and Function Policy; and

3.6. any other policies that may be established, from time to time, relating to accounting and financial reporting and disclosure processes; oversight of the external audit of the Corporation's financial statement; and oversight of the internal audit function.

Reporting

The Chair of the Committee, or another designated Member, shall report to the Board at each regular meeting on those matters which were dealt with by the Committee since the last regular meeting of the Board.

Other

1. The Committee shall perform such other functions as may, from time to time, be assigned to the Committee by the Board.

2. The Committee may approve, in circumstances that it considers appropriate, the engagement by the Committee or any Director of outside advisors or persons having special expertise at the expense of the Corporation.

11.3 Pre-Approval Policies and Procedures

The Audit Committee has established a policy which requires pre-approval of all audit and non-audit services provided to the Corporation and its subsidiaries by the Corporation's External Auditor. The Pre-Approval of Audit and Non-Audit Services Policy describes the services which may be contracted from the External Auditor and the limitations and authorization procedures related thereto. This policy defines services such as bookkeeping, valuations, internal audit and management functions which may not be contracted from the External Auditor and establishes an annual limit for permissible non-audit services not greater than the total fee for audit services. Audit Committee pre-approval is required for all audit and non-audit services.

11.4 External Auditor Service Fees

The fees paid by the Corporation to Ernst & Young LLP, the Corporation's External Auditors, during each of the last two fiscal years for audit, audit-related, tax and non-audit services were as follows:

Fortis
External Auditor Service Fees
($ thousands)

Ernst & Young LLP	**2008**	2007
Audit Fees	**$ 2,467.3**	$ 1,822.1
Audit-Related Fees	**853.0**	603.7
Tax Fees	**125.8**	181.9
Total	**$ 3,446.1**	$ 2,607.7

The increase in audit fees in 2008, as compared to 2007, primarily related to Caribbean Utilities associated with its change in auditors to Ernst & Young LLP for the fiscal year ended April 30, 2008, the requirement for an additional year-end audit associated with the change in the utility's year end to December 31, 2008 and increased audit work arising from the full year of Terasen inclusion as a subsidiary.

12.0 TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares and First Preference Shares of Fortis is Computershare Trust Company of Canada in Halifax, Montréal and Toronto.

Computershare Trust Company of Canada
9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
E: service@computershare.com
W: www.computershare.com/fortisinc

13.0 AUDITORS

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants, The Fortis Building, 7th Floor, 139 Water Street, St. John's, NL, A1C 1B2. The financial statements of the Corporation for the fiscal year ended December 31, 2008 have been audited by Ernst & Young LLP. Ernst & Young LLP report that they are independent of the Corporation in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Newfoundland.

14.0 ADDITIONAL INFORMATION

Reference is made to the MD&A on pages 20 through 79 of the 2008 Fortis Inc. Annual Report to Shareholders, which pages are incorporated herein by reference. Additional information relating to the Corporation can be found on SEDAR at www.sedar.com.

Further additional information, including officers' and directors' remuneration and indebtedness, principal holders of the securities of Fortis, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in the Management Information Circular of Fortis dated April 3, 2009 for the May 5, 2009 Annual Meeting of Shareholders. Additional financial information is also provided in the comparative consolidated financial statements and MD&A of Fortis for the year ended December 31, 2008.

Requests for additional copies of the above-mentioned documents, as well as the 2008 Annual Information Form, should be directed to the Corporate Secretary, Fortis, P.O. Box 8837, St. John's, NL, A1B 3T2 (telephone: 709.737.2800). In addition, such documentation and additional information relating to the Corporation is contained on the Corporation's website at www.fortisinc.com.

FORTIS INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2009

March 8, 2010

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2009

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DEFINITIONS OF CERTAIN TERMS

Certain terms used in the Annual Information Form for the year ended December 31, 2009 are defined below:

"2009 Annual Information Form" means the Fortis Inc. Annual Information Form for the year ended December 31, 2009;

"Abitibi" means AbitibiBowater Inc.;

"Advisory Panel" means the Advisory Panel on Canada's System of International Taxation;

"Algoma Power" means Algoma Power Inc.;

"AUC" means Alberta Utilities Commission;

"BAL" means Belize Aquaculture Limited;

"BC Hydro" means BC Hydro and Power Authority;

"BCUC" means British Columbia Utilities Commission;

"BELCOGEN" means Belize Cogeneration Energy Limited;

"BECOL" means Belize Electric Company Limited;

"Belize Electricity" means Belize Electricity Limited;

"BEPC" means Brilliant Expansion Power Corporation;

"BEWU" means Belize Energy Workers Union;

"Board" means Board of Directors of Fortis Inc.;

"BPC" means Brilliant Power Corporation;

"BZ" means Belizean currency, which is pegged to the United States currency (BZ$2.00=US$1.00);

"Canadian GAAP" means Canadian generally accepted accounting principles;

"Canadian Niagara Power" means Canadian Niagara Power Inc.;

"Caribbean Utilities" means Caribbean Utilities Company, Ltd.;

"CAW" means Canadian Auto Workers-Retail/Wholesale;

"CEP" means Communications, Energy and Paperworkers Union of Canada;

"CFE" means Comisión Federal de Electricidad;

"CICA" means Canadian Institute of Chartered Accountants;

"CIP" means Capital Investment Plan;

"COPE" means Canadian Office & Professional Employees Union;

"Cornwall Electric" means Cornwall Street Railway, Light and Power Company, Limited;

"Corporation" means Fortis Inc.;

"COS" means cost of service;

"CPA" means Canal Plant Agreement;

"CPC/CBT" means Columbia Power Corporation and the Columbia Basin Trust;

"CPI" means consumer price index;

"CRA" means Canada Revenue Agency;

"CUPE" means Canadian Union of Public Employees;

"DBRS" means DBRS Limited;

"ECAM" means energy cost adjustment mechanism;

"ERA" means Electricity Regulatory Authority;

"Exploits Partnership" means Exploits River Hydro Partnership between Abitibi and Fortis Properties Corporation;

"External Auditor" means the firm of chartered accountants registered with the Canadian Public Accountability Board or its successor and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

"FERC" means United States Federal Energy Regulatory Commission;

"First Preference Share, Series H" means Cumulative Redeemable Five-Year Fixed Rate Reset First Preference Shares, Series H;

"Fortis" means Fortis Inc.;

"FortisAlberta" means FortisAlberta Inc.;

"FortisAlberta Holdings" means FortisAlberta Holdings Inc.;

"FortisBC" means, collectively, the operations of FortisBC Inc. and its parent company, Fortis Pacific Holdings Inc., but excluding its wholly owned partnership, Walden Power Partnership;

"FortisOntario" means, collectively, the operations of Canadian Niagara Power, Cornwall Electric and Algoma Power. Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc.;

"FortisOntario Inc." means the successor to Canadian Niagara Power Company, Limited and the parent company of Canadian Niagara Power, Cornwall Electric and Algoma Power;

"Fortis Pacific Holdings" means Fortis Pacific Holdings Inc.;

“Fortis Properties” means Fortis Properties Corporation;

“Fortis Turks and Caicos” means, collectively, P.P.C. Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd.;

“FortisUS Energy” means FortisUS Energy Corporation;

“FortisWest” means FortisWest Inc.;

“GWh” means gigawatt hour(s);

“Hydro One” means Hydro One Networks Inc.;

“IASB” means International Accounting Standards Board;

“IBEW” means International Brotherhood of Electrical Workers;

“IESO” means Independent Electricity System Operator of Ontario;

“IFRS” means International Financial Reporting Standards;

“IRAC” means Island Regulatory and Appeals Commission;

“IRM” means Incentive Regulation Mechanism;

“ISO” means International Organization for Standardization;

“kWh” means kilowatt hour(s);

“MD&A” means the Corporation’s Management Discussion and Analysis, located on pages 20 through 81 of the Corporation’s 2009 Annual Report to Shareholders, prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations,* in respect of the Corporation’s annual and interim financial statements;

“Management” means, collectively, senior officers of the Corporation;

“Maritime Electric” means Maritime Electric Company, Limited;

“Moody’s” means Moody’s Investors Service;

“MW” means megawatt(s);

“NB Power” means New Brunswick Power Corporation;

“NEB” means National Energy Board;

“Newfoundland Hydro” means Newfoundland and Labrador Hydro;

“Newfoundland Power” means Newfoundland Power Inc.;

“NSA” means Negotiated Settlement Agreement;

“OEB” means Ontario Energy Board;

“Other Canadian Electric Utilities” means, collectively, the operations of FortisOntario and Maritime Electric;

“PBR” means performance-based rate-setting methodology for regulation of public utilities;

“PCB” means polychlorinated biphenyl;

“PIF” means productivity improvement factor;

“PJ” means petajoule(s);

“Point Lepreau” means NB Power Point Lepreau Nuclear Generating Station;

“Port Colborne Hydro” means Port Colborne Hydro Inc.;

“PUB” means Newfoundland and Labrador Board of Commissioners of Public Utilities;

“PUC” means Public Utilities Commission (Belize);

“PWU” means Power Workers Union, a CUPE affiliate as CUPE Local 1000;

“ROA” means regulated rate of return on rate base assets;

“ROE” means rate of return on common shareholders’ equity;

“S&P” means Standard & Poor’s;

“Teck Cominco” means Teck Cominco Metals Ltd.;

“Terasen Gas companies” means, collectively, the operations of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.;

“Terasen” means Terasen Inc., the holding company of the Terasen Gas companies;

“TGI” means Terasen Gas Inc.;

“TGVI” means Terasen Gas (Vancouver Island) Inc.;

“TGWI” means Terasen Gas (Whistler) Inc.;

“TIEA” means tax information-exchange agreements;

“TJ” means terajoule(s);

“TQM” means Trans Quebec & Maritimes Inc.;

“TransAlta” means TransAlta Utilities Corporation;

“UFCW” means United Food and Commercial Workers;

“USW” means United Steel Workers;

“UUWA” means United Utility Worker’s Association;

“VAD” means value added delivery;

“VIGJV” means Vancouver Island Gas Joint Venture;

“VINGPA” means Vancouver Island Natural Gas Pipeline Agreement;

“Walden” means Walden Power Partnership; and

“Whistler” means the Resort Municipality of Whistler.

1.0 CORPORATE STRUCTURE

The 2009 Annual Information Form has been prepared in accordance with National Instrument 52-102 – *Continuous Disclosure Obligations*. Financial information has been prepared in accordance with Canadian GAAP and is presented in Canadian dollars unless otherwise specified.

Except as otherwise stated, the information in the 2009 Annual Information Form is given as of December 31, 2009.

Fortis includes forward-looking information in the 2009 Annual Information Form within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. 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 2009 Annual Information Form, including the 2009 MD&A incorporated herein by reference, includes, but is not limited to, statements regarding: the expected increase in average annual energy production from the Macal River in Belize by the Vaca hydroelectric generating facility; the expected timing of regulatory decisions; negligible electricity sales growth is expected at the Corporation's regulated utilities in the Caribbean for 2010; organic revenue growth at Fortis Properties' Hospitality Division is expected to continue to be challenged in 2010; consolidated forecasted gross capital expenditures for 2010 and in total over the five-year period from 2010 through 2014; the nature, timing and amount of certain capital projects and their expected costs and time to complete; the expected impacts on Fortis of the economic downturn; the expectation of no significant decrease in annual consolidated operating cash flows in 2010 as a result of any continuation of the economic downturn; the expectation that the subsidiaries will be able to source the cash required to fund their 2010 capital expenditure programs; the expectation that the Corporation and its utilities will continue to have reasonable access to capital in the near to medium terms; expected consolidated long-term debt maturities and repayments in 2010 and on average annually over the next five years; no material increase in consolidated interest expense and/or fees associated with renewed and extended credit facilities is expected in 2010; no material adverse credit rating actions are expected in the near term; the expected impact of a change in the US dollar-to-Canadian dollar foreign exchange rate on basic earnings per common share in 2010; the estimated impact a decrease in revenue at Fortis Properties' Hospitality Division would have on basic earnings per common share; the expectation that counterparties to the Terasen Gas companies' gas derivative contracts will continue to meet their obligations; and the expectation of an increase in consolidated defined benefit net pension cost for 2010. The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major event; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no significant decline in capital spending in 2010; no severe and prolonged downturn in economic conditions; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the continued ability to hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas commodity prices; no significant variability in interest rates; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas supply; the continued ability to fund defined benefit pension plans; the absence of significant changes in government energy plans and environmental laws that may materially affect the operations and cash flows of the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; no material decrease in market energy sales prices; maintenance of information technology infrastructure; favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program. 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. Factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory risk; operating and maintenance risks; economic conditions; capital resources and liquidity risk; weather and seasonality; commodity price risk; derivative financial instruments and hedging; interest rate risk; counterparty risk; competitiveness of natural gas; natural gas supply; defined benefit pension plan performance and funding requirements; risks related to the development of the Terasen Gas

(Vancouver Island) Inc. franchise; the Government of British Columbia's Energy Plan; environmental risks; insurance coverage risk; loss of licences and permits; loss of service area; market energy sales prices; changes in the current assumptions and expectations associated with the transition to IFRS; changes in tax legislation; information technology infrastructure; an ultimate resolution of the expropriation of the assets of the Exploits Partnership that differs from what is currently expected by management; an unexpected outcome of legal proceedings currently against the Corporation; relations with First Nations; labour relations and human resources. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Risk Factors" in this 2009 Annual Information Form.

All forward-looking information in this 2009 Annual Information Form is qualified in its entirety by the above cautionary statements 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.

1.1 Name and Incorporation

Fortis is a holding company that was incorporated as 81800 Canada Ltd. under the *Canada Business Corporations Act* on June 28, 1977 and continued under the *Corporations Act* (Newfoundland and Labrador) on August 28, 1987.

The articles of incorporation of the Corporation were amended to: (a) change its name to Fortis on October 13, 1987; (b) set out the rights, privileges, restrictions and conditions attached to the Common Shares on October 15, 1987; (c) designate 2,000,000 First Preference Shares, Series A on September 11, 1990; (d) replace the class rights, privileges, restrictions and conditions attaching to the First Preference Shares and the Second Preference Shares on July 22, 1991; (e) designate 2,000,000 First Preference Shares, Series B on December 13, 1995; (f) designate 5,000,000 First Preference Shares, Series C on May 27, 2003; (g) designate 8,000,000 First Preference Shares, Series D and First Preference Shares, Series E on January 23, 2004; (h) amend the redemption provisions attaching to the First Preference Shares, Series D on July 15, 2005; (i) designate 5,000,000 First Preference Shares, Series F on September 22, 2006; (j) designate 9,200,000 First Preference Shares, Series G on May 20, 2008; and (k) designate 10,000,000 First Preference Shares, Series H on January 20, 2010.

Fortis redeemed all of its outstanding First Preference Shares, Series A and First Preference Shares, Series B on September 30, 1997 and December 2, 2002, respectively. On June 3, 2003, Fortis issued 5,000,000 First Preference Shares, Series C. On January 29, 2004, Fortis issued 8,000,000 First Preference Units, each unit consisting of one First Preference Share, Series D and one Warrant. During 2004, 7,993,500 First Preference Units were converted into 7,993,500 First Preference Shares, Series E and 6,500 First Preference Shares, Series D remained outstanding. On September 20, 2005, the 6,500 First Preference Shares, Series D were redeemed by the Corporation. On September 28, 2006, Fortis issued 5,000,000 First Preference Shares, Series F. On May 23, 2008, Fortis issued 8,000,000 First Preference Shares, Series G and on June 4, 2008 issued an additional 1,200,000 First Preference Shares, Series G, following the exercise of an over-allotment option in connection with the offering of the 8,000,000 First Preference Shares, Series G. On January 26, 2010, Fortis issued 10,000,000 First Preference Shares, Series H.

The corporate head and registered office of Fortis is located at the Fortis Building, Suite 1201, 139 Water Street, P.O. Box 8837, St. John's, NL, Canada, A1B 3T2.

1.2 Inter-Corporate Relationships

Fortis is principally an international distribution utility holding company. Its regulated holdings include electric distribution utilities in five Canadian provinces and three Caribbean countries and a natural gas utility in British Columbia. As at December 31, 2009, regulated utility assets comprised approximately 93 per cent of the Corporation's total assets, with the balance primarily comprised of non-regulated generation assets, mainly hydroelectric, across Canada and in Belize and Upper New York State, and hotels and commercial office and retail space in Canada.

The following table lists the principal subsidiaries of the Corporation, their jurisdictions of incorporation and the percentage of votes attaching to voting securities held directly or indirectly by the Corporation as at March 8, 2010. This table excludes certain subsidiaries, the total assets of which individually constituted less than 10 per cent of the Corporation's consolidated assets as at December 31, 2009, or the total revenue of which individually constituted less than 10 per cent of the Corporation's 2009 consolidated revenue. Additionally, the principal subsidiaries together comprise 79 per cent of the Corporation's consolidated assets as at December 31, 2009 and 76 per cent of the Corporation's 2009 consolidated revenue.

Principal Subsidiaries

Subsidiary	Jurisdiction of Incorporation	Percentage of votes attaching to voting securities beneficially owned, controlled or directed by the Corporation
Terasen	British Columbia	100
FortisAlberta [(1)]	Alberta	100
FortisBC Inc. [(2)]	British Columbia	100
Newfoundland Power	Newfoundland and Labrador	93.9[(3)]

(1) *FortisAlberta Holdings, an Alberta corporation, owns all of the shares of FortisAlberta. FortisWest, a Canadian corporation, owns all of the shares of FortisAlberta Holdings. Fortis owns all of the shares of FortisWest.*

(2) *Fortis Pacific Holdings, a British Columbia corporation, owns all of the shares of FortisBC Inc. FortisWest, a Canadian corporation, owns all of the shares of Fortis Pacific Holdings. Fortis owns all of the shares of FortisWest.*

(3) *Fortis owns all of the common shares; 182,300 First Preference Shares, Series G; 33,181 First Preference Shares, Series B; 13,000 First Preference Shares, Series D and 1,713 First Preference Shares, Series A of Newfoundland Power which, at March 8, 2010, represented 93.9 per cent of its voting securities. The remaining 6.1 per cent of Newfoundland Power's voting securities consist of First Preference Shares, Series A, B, D and G which are primarily held by the public.*

2.0 GENERAL DEVELOPMENT OF THE BUSINESS

2.1 Three-Year History

Over the past three years, the business operations of Fortis have increased significantly. Total assets have grown more than 2.2 times from $5.4 billion as at December 31, 2006 to $12.2 billion as at December 31, 2009. The Corporation's shareholders' equity has also grown 2.5 times from $1.4 billion as at December 31, 2006 to $3.5 billion as at December 31, 2009. Net earnings applicable to common shares have increased from $147 million in 2006 to $262 million in 2009.

The significant growth reflects the Corporation's profitable growth strategy for its principal businesses of regulated gas and electricity distribution. This strategy includes a combination of growth through acquisitions and organic growth through the Corporation's consolidated capital expenditure program.

The significant growth over the past three years primarily reflected the approximate $3.7 billion acquisition of Terasen in May 2007. The addition of Terasen's gas distribution business doubled the Corporation's investment in regulated rate base assets and marked the Corporation's expansion into natural gas distribution. In addition, Fortis increased its regulated utility investments in Canada through the acquisition of Algoma Power, in October 2009, for $75 million and increased its investment in Caribbean Utilities, over the three-year period, from approximately 54 per cent in 2006 to approximately 59 per cent held as at December 31, 2009. Algoma Power is a regulated electric distribution utility servicing approximately 12,000 customers in the District of Algoma in northern Ontario. The Corporation also increased its non-regulated investments, over the last three years, through the acquisition of three hotels in Canada.

Organic growth has been driven by the capital expenditure programs at FortisAlberta, FortisBC and the Terasen Gas companies. Total assets at FortisAlberta and FortisBC have grown by approximately 53 per cent and 33 per cent, respectively, over the past three years. Total assets at Terasen have grown approximately 22 per cent since May 17, 2007, the date of acquisition.

2.2 Outlook

The Corporation maintains a profitable growth strategy for its principal businesses of regulated gas and electricity distribution. This strategy includes a combination of growth through acquisitions and organic growth through the Corporation's consolidated capital expenditure program.

The Corporation's principal businesses of regulated gas and electricity distribution are capital intensive. Over the next five years, the Corporation's consolidated gross capital expenditures are expected to approach $5 billion. Approximately 70 per cent of the capital spending is expected be incurred at the regulated electric utilities, driven by FortisAlberta and FortisBC. Approximately 27 per cent of the capital spending is expected to be incurred at the regulated gas utilities and 3 per cent is expected to be incurred at the non-regulated operations. Capital expenditures at the regulated utilities are subject to regulatory approval.

Gross consolidated capital expenditures for 2010 are expected to be approximately $1.1 billion, as summarized in the following table. 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.

Forecast Gross Capital Expenditures *(1)* **Year Ending December 31, 2010**	
	($ millions)
Terasen Gas Companies	327
FortisAlberta *(2)*	363
FortisBC	168
Newfoundland Power	69
Other Canadian Electric Utilities	47
Regulated Electric Utilities – Caribbean	82
Non-Regulated Utility *(3)*	16
Fortis Properties	26
Total	**1,098**

(1) *Relates to utility capital assets, income producing properties and intangible assets and includes forecast capital expenditures associated with assets under construction. Includes forecast asset removal and site restoration expenditures, net of salvage proceeds, for those utilities where such expenditures are permissible in rate base. Excludes forecast capitalized non-cash equity component of the Allowance for Funds Used During Construction.*

(2) *Includes forecast payments to be made to the Alberta Electric System Operator for investment in transmission capital projects*

(3) *Includes forecast non-regulated utility and Corporate capital expenditures*

The Corporation's subsidiaries expect to have reasonable access to long-term capital in 2010 to fund their 2010 capital expenditure programs.

The Corporation continues to pursue acquisitions for profitable growth, focusing on strategic opportunities to acquire regulated natural gas and electric utilities in the United States, Canada and the Caribbean. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

3.0 DESCRIPTION OF THE BUSINESS

Fortis is principally an international distribution utility holding company. Its core business is highly regulated and is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation, and commercial office and retail space and hotels, which are treated as two separate segments. The Corporation's reporting segments allow Management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. Each reporting segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The operating segments of the Corporation are: (i) Regulated Gas Utilities - Canadian; (ii) Regulated Electric Utilities - Canadian; (iii) Regulated Electric Utilities - Caribbean; (iv) Non-Regulated - Fortis Generation; (v) Non-Regulated - Fortis Properties; and (vi) Corporate and Other.

The following sections describe the operations in each of the Corporation's reportable segments.

3.1 Regulated Gas Utilities - Canadian

3.1.1 *Terasen Gas Companies*

The Regulated Gas Utilities - Canadian segment comprises the natural gas transmission and distribution business of TGI, TGVI and TGWI, collectively referred to as the Terasen Gas companies.

TGI is the largest distributor of natural gas in British Columbia, serving approximately 839,000 residential, commercial and industrial customers in a service area that extends from Vancouver to the Fraser Valley and the interior of British Columbia.

TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island, and the distribution system on Vancouver Island and along the Sunshine Coast of British Columbia, serving approximately 98,000 residential, commercial and industrial customers.

In addition to providing transmission and distribution services to customers, TGI and TGVI also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through TGI's Southern Crossing Pipeline, from Alberta.

TGWI owns and operates the newly converted natural gas distribution system in Whistler, British Columbia, which provides service to approximately 2,600 residential and commercial customers.

The Terasen Gas companies own and operate more than 46,000 kilometres of natural gas distribution and transmission pipelines and met a peak day demand of 1,234 TJ in 2009.

Market and Sales

The Terasen Gas companies' annual customer gas volumes decreased to 207,230 TJ in 2009 from 221,122 TJ in 2008. Revenue was approximately $1.7 billion in 2009 compared to $1.9 billion in 2008.

The following table compares the composition of 2009 and 2008 revenue and gas volumes by customer class of the Terasen Gas companies.

Terasen Gas Companies Revenue and Gas Volumes by Customer Class				
	Revenue *(per cent)*		**PJ Volumes** *(per cent)*	
	2009	2008	**2009**	2008
Residential	**56.9**	57.7	**37.6**	35.5
Commercial	**33.9**	33.1	**22.9**	19.9
Small industrial	**1.7**	1.7	**2.8**	1.4
Large industrial and other	**0.1**	0.1	**0.1**	0.1
	92.6	92.6	**63.4**	56.9
Transportation and other	**7.4**	7.4	**36.6**	43.1
Total	**100.0**	100.0	**100.0**	100.0

Gas Purchase Agreements

In order to acquire supply resources that ensure reliable natural gas deliveries to its customers, the Terasen Gas companies purchase supply from a select list of producers, aggregators and marketers by adhering to strict standards of counterparty creditworthiness and contract execution and/or management procedures. TGI contracts for approximately 109 PJ of baseload and seasonal supply, of which 80 PJ is delivered off the Spectra Energy Gas transmission system. Approximately 11 PJ is comprised primarily of Alberta-sourced supply transported into British Columbia via TransCanada Pipeline Limited's Alberta and British Columbia systems. The remaining 18 PJ of baseload and seasonal supply is sourced at Sumas, British Columbia. TGVI contracts for approximately 11 PJ of annual supply comprised of base load and seasonal contracts, of which approximately 9 PJ is delivered off the Spectra Energy Gas transmission system and 2 PJ is sourced directly at Sumas.

Through the operation of regulatory deferrals, any difference between forecasted cost of natural gas purchases, as reflected in customer rates, and the actual cost of natural gas purchases is recovered from, or refunded to, customers in future rates. The majority of supply contracts in the current portfolio are seasonal for either the summer period (April to October) or winter period (November to March) with a few contracts one year or longer in length.

The Spectra Energy Gas transmission and TransCanada Pipeline Limited transportation tolls are regulated by the NEB, whose responsibilities include regulating pipeline tolls. The Terasen Gas companies pay both fixed and variable charges for use of the pipelines, which are recovered through rates paid by its customers.

Peak Shaving Arrangements

TGI and TGVI incorporate peak shaving and gas storage facilities into its portfolio to:

i. manage the load factor of baseload supply contracts throughout the year;
ii. eliminate the risk of supply shortages during a peak throughput day;
iii. reduce the cost of gas during winter months; and
iv. balance daily supply and demand on the distribution system.

The Terasen Gas companies' peak shaving and storage assets and contracts for 2010 include up to 30 PJ in storage capacity at various locations throughout British Columbia, Alberta and the Pacific Northwest of the United States. These storage facilities and supply from peak shaving contracts can deliver a maximum daily rate of 562 TJ on a combined basis during the coldest months of December through February.

TGVI maintains storage contracts with Unocal Canada Limited at the Aitken Creek Storage facility in Northern British Columbia and Northwest Natural Gas Company at the Mist Storage facility in Oregon, United States. TGVI's Aitken Creek storage contract consists of 2.1 PJ of capacity with 14.1 TJ of daily deliverability and its Mist storage contract consists of 0.69 PJ of capacity with 26.4 TJ of daily deliverability. TGVI also has access to an estimated 27.0 TJ of daily peak supply deliverability from various peak supply arrangements.

Off-System Sales

TGI is in its fourteenth year of off-system sales activities, in which any daily excess supply of gas is sold at the market-spot rate that allows for the recovery or mitigation of costs on unutilized supply and/or pipeline capacity. In 2008/2009, TGI marketed approximately 23.8 PJ of surplus gas and 41.3 PJ of excess pipeline capacity for a net pre-tax recovery of approximately $136 million. Through the Gas Supply Mitigation Incentive Plan established with the BCUC, $1.1 million (pre-tax) of these benefits accrued to shareholders with the remainder flowing through to customers in the form of reduced natural gas costs.

Unbundling

Over the past several years, TGI, the BCUC and other interested parties have laid the groundwork for the introduction of natural gas commodity unbundling in British Columbia. On November 1, 2004, commercial customers of TGI became eligible to buy their natural gas commodity supply from third-party suppliers. TGI continues to provide delivery of the natural gas. Approximately 80,000 commercial customers are eligible to participate in commodity unbundling. By December 31, 2009, approximately 19,800 customers had elected to participate in this program.

During 2006, the BCUC approved the offering of commodity supply choice to residential customers. The BCUC agreed to open a portion of the province of British Columbia's residential natural gas market to competition, allowing homeowners to sign long-term fixed-price contracts for natural gas with companies other than TGI, effective May 2007. Consumers had the option to remain with TGI or sign with another market participant, in which case they began receiving gas at that market participant's rate beginning in November 2007. TGI continues to provide delivery service to unbundled customers and delivery margins are not expected to be impacted by migration of residential customers to alternative commodity suppliers. Approximately 752,000 residential customers are eligible to participate in commodity unbundling. By December 31, 2009, approximately 118,300 customers had elected to participate in this program. Neither residential nor commercial unbundling has had a material effect on the delivery margins of TGI.

Legal Proceedings

On March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform (the "Minister") in British Columbia issued a decision in respect of the appeal by TGI of an assessment of additional British Columbia Social Service Tax in the amount of approximately $37 million associated with the Southern Crossing Pipeline, which was completed in 2000. The Minister reduced the assessment to $7 million, including interest, which has been paid in full to avoid accruing further interest and recorded as a long-term regulatory deferral asset. TGI was successful in its appeal to the Supreme Court of British Columbia in June 2009. The province of British Columbia has been granted leave to appeal the decision to the British Columbia Court of Appeal.

During 2007 and 2008, a non-regulated subsidiary of Terasen received Notices of Assessment from CRA for additional taxes related to the taxations years 1999 through 2003. The exposure has been fully provided for in the Corporation's 2009 consolidated financial statements. Terasen has begun the appeal process associated with the assessments.

On July 16, 2009, Terasen was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to a pipeline rupture in July 2007. Terasen has filed a statement of defence but the claim is in its early stages and the amount and outcome of it is indeterminable at this time and, accordingly, no amount has been accrued in the Corporation's 2009 consolidated financial statements.

In 2008, the VIGJV commenced a lawsuit against TGVI seeking damages for alleged overpayments of past tolls and declarations for reduction of its future tolls. The Statement of Claim did not quantify damages and the case did not reach the stage where either party formally quantified VIGJV's claims. In December 2009, VIGJV abandoned its claim and in January 2010, the lawsuit was dismissed by consent dismissal order. The matter is now fully concluded.

Human Resources

As at December 31, 2009, the Terasen Gas companies employed 1,295 full-time equivalent employees. Approximately 68 per cent of the employees are represented by IBEW, Local 213 and COPE, Local 378 under collective agreements that expire on March 31, 2011 and March 31, 2012, respectively.

3.2 Regulated Electric Utilities - Canadian

3.2.1 *FortisAlberta*

FortisAlberta is a regulated electric distribution utility in the province of Alberta. Its business is the ownership and operation of regulated electric distribution facilities that distribute electricity generated by other market participants from high-voltage transmission substations to end-use customers. FortisAlberta is not involved in the generation, transmission or direct sale of electricity. FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, totalling approximately 110,000 kilometres of distribution lines. The Company's distribution network serves approximately 480,000 customers, comprising residential, commercial, farm and industrial consumers of electricity, and met a record peak demand of 3,365 MW in 2009.

Market and Sales

FortisAlberta's annual energy deliveries increased to 15,865 GWh in 2009 from 15,722 GWh in 2008. Revenue was $331 million in 2009 compared to $300 million in 2008.

The following table compares the composition of FortisAlberta's 2009 and 2008 revenue and energy deliveries by customer class.

FortisAlberta
Revenue and Energy Deliveries by Customer Class

	Revenue *(per cent)*		**GWh Deliveries** [(1)] *(per cent)*	
	2009	2008	**2009**	2008
Residential	**30.7**	30.5	**16.9**	16.4
Large commercial and industrial [(2)]	**22.7**	22.6	**60.3**	60.9
Farms	**12.9**	12.9	**8.6**	8.2
Small commercial	**11.4**	11.6	**8.0**	8.0
Small oilfield	**9.4**	9.6	**5.8**	6.0
Other [(3)]	**12.9**	12.8	**0.4**	0.5
Total	**100.0**	100.0	**100.0**	100.0

(1) GWh percentages presented exclude FortisAlberta's GWh deliveries to "transmission-connected" customers. These deliveries consist primarily of large-scale industrial customers directly connected to the transmission grid. The related transmission revenue is recorded net of expenses in other revenue in FortisAlberta's financial statements.
(2) Included in the large commercial and industrial customer class are large oilfield customers
(3) Includes revenue from sources other than the delivery of electricity, including that related to street-lighting services, net transmission revenue, rate riders, deferrals and adjustments

Franchise Agreements

Most of FortisAlberta's residential, commercial and industrial customers, located within a city, town, or village boundary, are served through franchise agreements between the Company and the customers' municipality of residence. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta that are located in their municipal boundaries. In Alberta, the standard franchise agreement, which could include a franchise fee payable to the municipality, is generally for ten years and may be renewed for five years upon mutual consent of the parties. All municipal franchises are governed by legislation that requires the municipality or the utility to give notice and obtain AUC approval if it intends to terminate its franchise agreement. Any franchise agreement that is not renewed continues in effect until either the Company or the municipality terminates it with AUC permission. If a franchise agreement is terminated and the municipality subsequently exercises its right under the *Municipal Government Act* (Alberta) to purchase FortisAlberta's distribution network within the municipality's boundaries or annexed area, the Company must be compensated. Compensation would include payment for FortisAlberta's assets on the basis of replacement cost less depreciation.

FortisAlberta serves 141 municipalities, of which 140 are on standardized individual franchise agreements. Substantially all of these agreements expire between 2011 and 2017. The Company is in the process of renewing or negotiating franchise agreements with one additional municipality and two summer villages.

Human Resources

As at December 31, 2009, FortisAlberta had 996 full-time equivalent employees. Approximately 73 per cent of the employees of the Company are members of a labour association represented by UUWA, Local 200, under a three-year collective agreement that expires on December 31, 2010.

3.2.2 *FortisBC*

FortisBC includes FortisBC Inc., an integrated electric utility that owns a network of generation, transmission and distribution assets located in the southern interior of British Columbia. FortisBC Inc. serves a diverse mix of approximately 159,000 customers, of whom approximately 111,000 are served directly by the Company's assets while the remainder are served through the wholesale supply of power to municipal distributors. In 2009, FortisBC Inc. met a peak demand of 714 MW. Residential customers represent the largest customer segment of the Company. FortisBC's transmission and distribution assets include approximately 7,000 kilometres of transmission and distribution lines and 66 distribution substations.

FortisBC also includes operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Cominco, the 149-MW Brilliant hydroelectric plant and 120-MW Brilliant expansion plant, both owned by CPC/CBT, the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT, and the distribution system owned by the City of Kelowna.

Market and Sales

FortisBC has a diverse customer base composed primarily of residential, general service, industrial and municipal wholesale, and other industrial customers. Annual electricity sales were 3,157 GWh in 2009 compared to 3,087 GWh in 2008. Revenue increased to $253 million in 2009 from $237 million in 2008.

The following table compares the composition of FortisBC's 2009 and 2008 revenue and electricity sales by customer class.

FortisBC
Revenue and Electricity Sales by Customer Class

	Revenue *(per cent)*		**GWh Sales** *(per cent)*	
	2009	2008	**2009**	2008
Residential	**44.0**	43.4	**41.0**	39.5
General service	**24.5**	24.6	**23.2**	23.4
Wholesale	**19.6**	19.3	**29.4**	28.9
Industrial	**5.5**	6.1	**6.4**	8.2
Other [(1)]	**6.4**	6.6	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) Includes revenue from sources other than from the sale of electricity, including revenue of Fortis Pacific Holdings associated with non-regulated operating, maintenance and management services

Generation and Power Supply

FortisBC Inc. meets the electricity supply requirements of its customers through a mix of its own generation and power purchase contracts. FortisBC Inc. owns four regulated hydroelectric generating plants on the Kootenay River with an aggregate capacity of 223 MW and annual energy output of approximately 1,591 GWh, which provide approximately 45 per cent of the Company's energy needs and 30 per cent of its capacity needs. FortisBC Inc. meets the balance of its requirements through a portfolio of long-term and short-term power purchase agreements.

FortisBC Inc.'s four hydroelectric generating facilities are governed by the CPA. The CPA is a multi-party agreement that enables the five separate owners of eight major hydroelectric generating plants, with a combined capacity of approximately 1,600 MW and located in relatively close proximity to each other, to coordinate the operation and dispatch of their plants.

The following table lists the plants and their owners.

Plant	Capacity (MW)	Owners
Canal Plant	580	BC Hydro
Waneta Dam	493	Teck Cominco
Kootenay River System	223	FortisBC Inc.
Brilliant Dam and Expansion	269	BPC and BEPC
Total	**1,565**	

BPC, BEPC, Teck Cominco and FortisBC Inc. are collectively defined in the CPA as the Entitlement Parties. 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 storage reservoirs, and through the coordinated operation of generating plants, to generate more power from their respective generating resources than they could if they operated independently. Under the CPA, BC Hydro takes into its system all power actually generated by all seven plants owned by the Entitlement Parties. In exchange for permitting BC Hydro to determine the output of these facilities, each of the Entitlement Parties is contractually entitled to a fixed annual entitlement of capacity and energy from BC Hydro, which is currently based on 50-year historical water flows. The Entitlement Parties receive their defined entitlements irrespective of actual water flows to the Entitlement Parties' generating plants and are, accordingly, insulated from the risk of water availability.

The majority of FortisBC Inc.'s remaining electricity supply is acquired through long-term power purchase contracts, consisting of the following:

i. a 149-MW long-term power purchase agreement with BPC terminating in 2056;
ii. a 200-MW power purchase agreement with BC Hydro terminating in 2013; and
iii. a number of small power purchase contracts with independent power producers.

The majority of these purchase contracts have been approved by the BCUC and prudently incurred costs thereunder flow through to customers through FortisBC Inc.'s electricity rates.

Although FortisBC Inc. can currently meet most of its customer supply requirements from its own generation and the long-term 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 incurred and accurately forecasted, are largely flowed through to customers. FortisBC Inc. generally makes arrangements prior to the winter season to acquire power at known prices should the need arise.

Legal Proceedings

The British Columbia Ministry of Forests has alleged breaches of the Forest Practices Code and negligence relating to a fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC Inc. In addition, the Company has been served with a filed writ and statement of claim by private landowners in relation to the same matter. The Company is communicating with its insurers and has filed a statement of defence in relation to both of the actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the Corporation's 2009 consolidated financial statements.

Human Resources

As at December 31, 2009, FortisBC had 540 full-time equivalent employees. FortisBC has a collective agreement with COPE, Local 378, expiring on January 31, 2011, and a collective agreement with IBEW, Local 213, expiring on January 31, 2013. The two collective agreements cover approximately 76 per cent of employees.

3.2.3 *Newfoundland Power*

Newfoundland Power is the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving more than 239,000 customers, or 85 per cent, of the province's electricity consumers. Newfoundland Power met a peak demand of 1,219 MW in 2009. The balance of the population is served by Newfoundland's other electric utility, Newfoundland Hydro, which also serves several larger industrial customers. Newfoundland Power owns and operates approximately 11,000 kilometres of transmission and distribution lines.

Market and Sales

Annual weather-adjusted electricity sales increased to 5,299 GWh in 2009 from 5,208 GWh in 2008. Revenue increased to $527 million in 2009 from $517 million in 2008.

The following table compares the composition of Newfoundland Power's 2009 and 2008 revenue and electricity sales by customer class.

Newfoundland Power
Revenue and Electricity Sales by Customer Class

	Revenue [(1)] *(per cent)*		**GWh Sales** [(1)] *(per cent)*	
	2009	2008	**2009**	2008
Residential	**59.0**	58.9	**60.4**	60.1
Commercial and Street Lighting	**37.0**	37.3	**39.6**	39.9
Other [(2)]	**4.0**	3.8	-	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Revenue and electricity sales reflect weather-adjusted values pursuant to Newfoundland Power's weather normalization reserve.*
(2) *Includes revenue from sources other than from the sale of electricity, the most significant being joint-use of pole revenue*

Power Supply

Approximately 92 per cent of Newfoundland Power's energy requirements is purchased from Newfoundland Hydro. The principal terms of the supply arrangements with Newfoundland Hydro are regulated by the PUB on a basis similar to that upon which Newfoundland Power's service to its customers is regulated.

Newfoundland Power operates 30 small generating facilities, which generate approximately 8 per cent of the electricity sold by Newfoundland Power. The Company's hydroelectric generating plants have a total capacity of 97 MW. The diesel plants and gas turbines have a total capacity of approximately 7 MW and 36 MW, respectively.

Legal Proceedings

The City of St. John's has given formal notice of its intention to terminate Newfoundland Power's rights to use the Mobile River watershed for the generation of electricity. The effective date of the notice to terminate the lease was March 1, 2009. The Company held these rights under a lease dated November 23, 1946, which was amended by an agreement dated October 21, 1949. The two hydroelectric generating plants affected by the lease have a combined capacity of approximately 12 MW and generate annual production of 49 GWh, representing less than one per cent of the Company's total energy requirements. To exercise the termination provision of the lease, the City of St. John’s is required to pay to the Company the value of all works and erections employed in the generation and transmission of electricity using the water of the Mobile River watershed. In accordance with the terms of the lease, an arbitration panel was appointed in 2008 for the purpose of determining the value of the affected assets. On March 9, 2009, the panel issued a ruling on certain preliminary questions. A majority of the panel ruled that termination of the lease will not be effective until payment to the Company of the value of the assets, and that the value of the payment is to be based on a valuation of the assets as a going concern, including the land and water rights.

The City of St. John’s has applied to the Supreme Court of Newfoundland and Labrador to have the preliminary ruling of the arbitration panel set aside. The application was heard by the Court in June 2009 and a decision is pending.

Human Resources

As at December 31, 2009, Newfoundland Power had 568 full-time equivalent employees, of which approximately 55 per cent were members of bargaining units represented by IBEW, Local 1620.

The Company has two collective agreements governing its union employees represented by IBEW, Local 1620. The collective agreements were ratified in February and April 2009. Both collective agreements expire September 30, 2011.

3.2.4 *Other Canadian Electric Utilities*

Other Canadian Electric Utilities includes the operations of Maritime Electric and FortisOntario.

Maritime Electric

The Corporation, through FortisWest, holds all of the common shares of Maritime Electric. Maritime Electric operates an integrated electric utility that directly supplies approximately 74,000 customers, constituting 90 per cent of electricity consumers on Prince Edward Island. Maritime Electric purchases most of the energy it distributes to its customers from NB Power, a provincial Crown Corporation, through various energy purchase agreements. Maritime Electric’s system is connected to the mainland power grid via two submarine cables between Prince Edward Island and New Brunswick, which are leased from the Government of Prince Edward Island. Maritime Electric owns and operates generating plants with a combined capacity of 150 MW on Prince Edward Island and met a peak demand of 219 MW in 2009. Maritime Electric owns and operates approximately 5,300 kilometres of transmission and distribution lines.

FortisOntario

The Corporation’s wholly owned regulated utility investments in Ontario, collectively FortisOntario, provides integrated electric utility service to approximately 64,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and, as of October 2009, the District of Algoma in Ontario. Included in Canadian Niagara Power’s accounts is the operation of the electricity distribution business of Port Colborne Hydro, which has been leased from the City of Port Colborne under a ten-year lease agreement that expires in April 2012. FortisOntario also owns a 10 per cent interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies serving approximately 38,000 customers.

FortisOntario met a combined peak demand of 265 MW in 2009. FortisOntario owns and operates approximately 3,300 kilometres of transmission and distribution lines.

Market and Sales

Annual electricity sales were 2,195 GWh in 2009 compared to 2,182 GWh in 2008. Revenue was $279 million in 2009 compared to $262 million in 2008.

The following table compares the composition of Other Canadian Electric Utilities' 2009 and 2008 revenue and electricity sales by customer class.

Other Canadian Electric Utilities
Revenue and Electricity Sales by Customer Class

	Revenue *(per cent)*		**GWh Sales** *(per cent)*	
	2009 [(1)]	2008	**2009** [(1)]	2008
Residential	**44.1**	43.4	**43.3**	42.4
Commercial and industrial	**48.3**	49.3	**56.1**	57.3
Other [(2)]	**7.6**	7.3	**0.6**	0.3
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes financial results of Algoma Power from October 2009*
(2) *Includes revenue from sources other than from the sale of electricity*

Power Supply

Maritime Electric

Maritime Electric purchased 86 per cent of the electricity required to meet its customers' needs from NB Power in 2009. The balance was met through Maritime Electric's on-Island generation facilities and the purchase of wind energy produced on Prince Edward Island. Maritime Electric's generation facilities are used primarily for peaking, submarine-cable loading issues and emergency purposes.

Maritime Electric generally purchases some of its electricity requirements from Point Lepreau. A major refurbishment began in 2008 and is expected to be completed in early 2011, extending the facility's estimated life an additional 25 years. The cost of replacement energy during the refurbishment of Point Lepreau is expected to be recovered from customers through the operation of the ECAM. To date, replacement energy costs for 2008 have been collected from customers and costs for 2009 have been approved for deferral for future collection from customers, as approved by IRAC.

Legislation proclaimed by the Government of Prince Edward Island will see an increased reliance by Maritime Electric on renewable energy sources, such as wind-powered energy, located on Prince Edward Island. Maritime Electric's goal is that 30 per cent of its annual energy sales be sourced from renewable energy supply by 2013. In 2006, the Company signed an agreement with PEI Energy Corporation that will see the Company purchase 39 MW of wind-powered energy from PEI Energy Corporation's new wind farm. Approximately 14 per cent of total energy supply was derived from wind-powered generation in 2009.

FortisOntario

The power requirements of FortisOntario's service areas are provided from various sources. Canadian Niagara Power purchases its power requirements for Fort Erie and Port Colborne from the IESO. Canadian Niagara Power purchases approximately 73 per cent of energy requirements for Gananoque through monthly energy purchases from Hydro One and the remaining 27 per cent is purchased from six hydroelectric generating plants owned by Fortis Properties. Algoma Power purchases 100 per cent of its energy from the IESO.

Under the Standard Supply Code of the OEB, Canadian Niagara Power is obliged to provide Standard Service Supply to all its customers who do not choose to contract with an electricity retailer. This energy is provided to customers at either regulated or market prices.

Cornwall Electric purchases 100 per cent of its power requirements from Hydro-Québec Energy Marketing under two fixed-term contracts. The first contract, which represents approximately 37 per cent of the power supply, is a 45-MW contract with a 60 per cent capacity factor. The second contract, supplying the remainder of Cornwall Electric's energy requirement, is a 100-MW capacity and energy contract. Both contracts expire in December 2019.

Legal Proceedings

In April 2006, CRA reassessed Maritime Electric's 1997-2004 taxation years. The reassessment encompasses the Company's tax treatment, specifically the Company's timing of deductions, with respect to: (i) the ECAM in the 2001-2004 taxation years; (ii) customer rebate adjustments in the 2001 - 2003 taxation years; and (iii) the Company's payment of approximately \$6 million on January 2, 2001 associated with a settlement with NB Power regarding its \$450 million write-down of Point Lepreau in 1998. Maritime Electric believes it has reported its tax position appropriately in all respects and has filed a Notice of Objection with the Chief of Appeals at CRA. In December 2008, the Appeals Division of CRA issued a Notice of Confirmation which confirmed the April 2006 reassessments. In March 2009, the Company filed an Appeal to the Tax Court of Canada.

Should Maritime Electric be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately \$14 million in taxes and accrued interest. As at December 31, 2009, Maritime Electric has provided for this amount through future and current income taxes payable. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA. The amount currently on deposit with CRA arising from the reassessment is approximately \$6 million.

Human Resources

As at December 31, 2009, Maritime Electric had 179 full-time equivalent employees, of which approximately 70 per cent were represented by IBEW, Local 1432. The collective agreement with IBEW, Local 1432, expired in December 2008. In February 2010, a new collective agreement, which expires December 31, 2013, was ratified by the union.

As at December 31, 2009, FortisOntario had 184 full-time equivalent employees, of which approximately 64 per cent were represented by CUPE, Local 137 and IBEW, Local 636, in the Niagara Region; IBEW, Local 636, in Gananoque; and PWU in the Algoma region. The collective agreements governing these employees expire, or expired, on April 30, 2012, May 31, 2012, July 31, 2012, and December 31, 2009, respectively. Algoma Power and PWU are currently negotiating a new collective agreement.

3.3 Regulated Electric Utilities - Caribbean

Regulated Electric Utilities - Caribbean operations are comprised of Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos.

Belize Electricity, the principal distributor of electricity in Belize, Central America, serves approximately 76,000 customers, owns more than 2,900 kilometres of transmission and distribution lines and met a peak demand of 76 MW in 2009. The Corporation holds an approximate 70 per cent controlling ownership interest in Belize Electricity.

Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 25,000 customers. The Company met a record peak demand of approximately 97.5 MW in 2009.

Caribbean Utilities owns and operates approximately 555 kilometres of transmission and distribution lines. Fortis holds an approximate 59 per cent controlling ownership interest in the utility. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U).

Fortis Turks and Caicos, wholly owned by Fortis, serves more than 9,000 customers, or 85 per cent, of electricity consumers, in the Turks and Caicos Islands and met a combined record peak demand of 29.6 MW in 2009. Fortis Turks and Caicos owns and operates approximately 235 kilometres of transmission and distribution lines. The Company is the principal distributor of electricity in the Turks and Caicos Islands pursuant to 50-year licences that expire in 2036 and 2037.

Market and Sales

Annual electricity sales decreased to 1,140 GWh in 2009 from 1,203 GWh in 2008. Annual revenue decreased to $339 million in 2009 from $408 million in 2008. Electricity sales and revenue for 2008, however, included electricity sales and revenue of Caribbean Utilities for the 14 months ended December 31, 2008, due to a change in the utility's fiscal year end in 2008.

The following table compares the composition of Regulated Electric Utilities - Caribbean's revenue and electricity sales by customer class for the years ended 2009 and 2008.

Regulated Electric Utilities – Caribbean *(1) (2)*
Revenue and Electricity Sales by Customer Class

	Revenue *(3)* *(per cent)*		**GWh Sales** *(3)* *(per cent)*	
	2009	2008	**2009**	2008
Residential	**48.0**	46.7	**48.4**	47.3
Commercial, industrial and street lighting	**50.0**	51.3	**51.6**	52.7
Other *(4)*	**2.0**	2.0	-	-
Total	**100.0**	100.0	**100.0**	100.0

(1) Includes Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos
(2) During 2008, Caribbean Utilities changed its fiscal year end from April 30 to December 31, which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008. Prior to the fourth quarter of 2008, Fortis was consolidating the financial results of Caribbean Utilities on a two-month lag basis. During 2009, the financial reporting periods of the Corporation coincided with the financial reporting periods of Caribbean Utilities.
(3) Iincludes 100 per cent of the revenue and electricity sales of Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos.
(4) Includes revenue from sources other than from the sale of electricity

Power Supply

In 2009, 65 per cent of the energy demand of Regulated Electric Utilities - Caribbean was sourced from gas turbine and diesel-powered generation. The majority of the remaining energy demand was sourced from hydroelectric generating facilities in Belize and purchased from CFE.

Belize Electricity meets its energy demand from multiple sources, which include power purchases from: (i) the Mollejon and Chalillo hydroelectric generating facilities owned and operated by BECOL; (ii) CFE, the Mexican state-owned power company; (iii) the Hydro Maya hydroelectric generating plant owned by Hydro Maya Limited; (iv) the heavy fuel oil plant operated by BAL; (v) the cogeneration facility owned by BELCOGEN; and (vi) its own diesel-powered and gas-turbine generation. All major load centers are connected to Belize's national electricity system, which is connected with the Mexican national electricity grid, allowing Belize Electricity to optimize its power supply options. Belize Electricity purchased and produced 473 GWh of electricity in 2009, of which 96 per cent was purchased from the Mollejon and Chalillo hydroelectric generating facilities, CFE, Hydro Maya Limited, BAL and BELCOGEN. The balance was produced by Belize Electricity's installed generating capacity of 34 MW, including a 22-MW gas-turbine generating facility.

In October 2009, the CFE of Mexico cancelled the guaranteed power supply contract for firm energy with Belize Electricity, citing force majeure reasons. The contract was to expire in December 2010. CFE has stated that its generating capacity has been significantly limited as a result of problems with gas availability, generation equipment and shortfall in hydroelectric production. CFE is proposing to negotiate a new contract to provide up to 50 MW of economic and emergency energy to Belize Electricity. CFE continues to supply Belize Electricity with power when available. There is sufficient in-country generation to meet energy demand in Belize without supply from CFE.

Caribbean Utilities relies upon diesel-powered generation to produce electricity for Grand Cayman. Grand Cayman has neither hydroelectric potential nor inherent thermal resources and the Company must rely upon diesel fuel imported to Grand Cayman primarily from refineries in the Caribbean and the Gulf of Mexico. The Company has an installed generating capacity of approximately 153 MW.

Fortis Turks and Caicos relies upon diesel-powered generation, which has a combined generating capacity of 54 MW, to produce electricity for its customers.

Legal Proceedings

Belize Electricity is involved in a number of legal proceedings relating to the PUC's Final Decision on Belize Electricity's 2008/2009 Rate Application. For further information, refer to the "Regulation - Material Regulatory Decisions and Applications" section of this 2009 Annual Information Form.

Human Resources

As at December 31, 2009, Regulated Electric Utilities - Caribbean employed 593 full-time equivalent employees. The 196 employees at Caribbean Utilities and 105 employees at Fortis Turks and Caicos are non-unionized. Of the 292 full-time equivalent employees at Belize Electricity, approximately 51 per cent were represented by BEWU. The Company's collective agreement with BEWU was signed in July 2008 and is to be reviewed every five years.

3.4 Non-Regulated - Fortis Generation

The following table summarizes the Corporation's non-regulated generation assets by location.

Fortis Generation
Non-Regulated Generation Assets

Location	Plants	Fuel	Capacity (MW)
Belize [(1)]	3	hydro	51
Ontario	7	hydro, thermal	13
Central Newfoundland [(2)]	2	hydro	36
British Columbia	1	hydro	16
Upper New York State	4	hydro	23
Total	**17**		**139**

(1) *Includes the 19-MW Vaca hydroelectric generating facility, which will be commissioned in March 2010.*
(2) *The two central Newfoundland plants were expropriated by the Government of Newfoundland and Labrador in December 2008. Effective February 12, 2009, the Corporation discontinued the consolidation method of accounting for its investment in central Newfoundland.*

The Corporation's non-regulated generation operations consist of its 100 per cent ownership interest in each of BECOL, FortisOntario and FortisUS Energy, as well as non-regulated generation assets owned by Fortis Properties and FortisBC Inc.

Non-regulated generation operations in Belize consist of the operations of the 25-MW Mollejon, the 7-MW Chalillo and, as of March 2010, the 19-MW Vaca hydroelectric generating facilities. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements expiring in 2055 and 2060 and a franchise agreement with the Government of Belize. Under these agreements, the Mollejon hydroelectric generating facility will be transferred to the Government of Belize in 2036, after which it will be leased at an annually increasing rate for a term expiring in 2055.

The US$53 million 19-MW hydroelectric generating facility at Vaca on the Macal River in Belize will be commissioned in March 2010. The facility was constructed downstream from the Chalillo and Mollejon hydroelectric generation facilities and is expected to increase average annual energy production from the Macal River by approximately 80 GWh to 240 GWh.

Non-regulated generation operations of FortisOntario include the operation of a 5-MW gas-powered cogeneration plant in Cornwall. The 75 MW water-right entitlement associated with the Rankine hydroelectric generating facility in Ontario expired on April 30, 2009, at the end of a 100-year term. Fortis Properties, a non-regulated wholly owned subsidiary, operates six small hydroelectric generating facilities in eastern Ontario with a combined capacity of 8 MW.

Fortis Properties also has non-regulated generation operations in central Newfoundland that are conducted through the Corporation's indirect 51 per cent interest in the Exploits Partnership. Through the Exploits Partnership, 36 MW of additional capacity was developed and installed at two of Abitibi's hydroelectric generating plants in central Newfoundland. The Exploits Partnership sells its output to Newfoundland Hydro under a 30-year power purchase agreement expiring in 2033. Effective February 12, 2009, the Corporation discontinued the consolidation method of accounting for these operations, necessitated by the actions of the Government of Newfoundland and Labrador related to its expropriation of the assets of the Exploits Partnership (see the "Legal Proceedings" section that follows).

The non-regulated generation operations of FortisBC Inc., conducted through Walden, its wholly owned partnership, consist of the 16-MW run-of-river hydroelectric generating plant near Lillooet, British Columbia. This plant is a non-regulated operation that sells its entire output to BC Hydro under a power purchase agreement expiring in 2013.

Through FortisUS Energy, an indirect wholly owned subsidiary, the Corporation owns and operates four hydroelectric generating facilities in Upper New York State with a combined capacity of approximately 23 MW operating under licences from FERC. All four hydroelectric generating facilities sell energy at current market rates.

Market and Sales

Annual energy sales from non-regulated generation assets were 583 GWh in 2009 compared to 1,217 GWh in 2008. Revenue was $39 million in 2009 compared to $82 million in 2008. Revenue and energy sales for 2009 included 4 months of revenue and energy sales associated with the Rankine hydroelectric facility in Ontario compared to 12 months in 2008, due to the expiration of the Rankine water rights in April 2009. Revenue and energy sales for 2009 reflected contribution from central Newfoundland operations for only 1½ months compared to an entire year in 2008 (see "Legal Proceedings" section that follows).

The following table compares the composition of Fortis Generation's 2009 and 2008 revenue and energy sales by location.

Fortis Generation Revenue and Energy Sales by Location				
	Revenue *(per cent)*		GWh Sales *(per cent)*	
	2009	2008	**2009**	2008
Belize	**46.1**	20.8	**30.9**	15.8
Ontario [(1)]	**31.0**	42.7	**46.5**	58.8
Central Newfoundland [(2)]	**9.1**	25.6	**3.3**	14.6
British Columbia	**4.2**	2.2	**4.9**	2.7
Upper New York State	**9.6**	8.7	**14.4**	8.1
Total	**100.0**	100.0	**100.0**	100.0

[(1)] *Reflects revenue and energy sales associated with the Rankine hydroelectric facility until April 30, 2009*

[(2)] *Reflects the discontinuance of the consolidation method of accounting for the financial results of the operations in central Newfoundland, effective February 12, 2009*

Legal Proceedings

<u>Exploits Partnership</u>

The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi. The Exploits Partnership operated two non-regulated hydroelectric generation plants in central Newfoundland with a combined capacity of approximately 36 MW. In December 2008, the Government of Newfoundland and Labrador expropriated Abitibi's hydroelectric assets and water rights in Newfoundland, including those of the Exploits Partnership. The newsprint mill in Grand Falls-Windsor closed on February 12, 2009, subsequent to which the day-to-day operations of the Exploits Partnership's hydroelectric generating facilities were assumed by Nalcor Energy, a Crown corporation, as an agent for the Government of Newfoundland and Labrador with respect to expropriation matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi in the province. The loss of control over cash flows and operations has required Fortis to cease consolidation of the Exploits Partnership, effective February 12, 2009. Discussions between Fortis Properties and Nalcor Energy with respect to expropriation matters are ongoing.

Human Resources

At December 31, 2009, Fortis Generation employed 29 full-time equivalent personnel, none of whom participate in a collective agreement.

3.5 Non-Regulated - Fortis Properties

Fortis Properties owns and operates 21 hotels, comprised of more than 4,100 rooms, in eight Canadian provinces and approximately 2.8 million square feet of commercial office and retail space primarily in Atlantic Canada. As a wholly owned subsidiary of Fortis, Fortis Properties is the Corporation's vehicle for non-utility diversification and growth.

Revenue was $218 million in 2009 compared to $207 million in 2008. In 2009, Fortis Properties derived approximately 29 per cent of its revenue from real estate operations and 71 per cent of its revenue from hotel operations. Fortis Properties derived approximately 44 per cent of its 2009 operating income from real estate operations and 56 per cent from hotel operations.

Fortis Properties' Real Estate Division is anchored by high-quality tenants under long-term leases. The Real Estate Division ended 2009 with 96.2 per cent occupancy, slightly below the rate of 96.8 per cent as at the end of 2008. In contrast, the average national occupancy rate was 90.2 per cent at the end of 2009, compared to 93.3 per cent at the end of 2008.

The following table sets out the office and retail properties owned by Fortis Properties.

Fortis Properties
Office and Retail Properties

Property	Location	Type of Property	Gross Lease Area *(square feet 000s)*
Fort William Building	St. John's, NL	Office	188
Cabot Place I	St. John's, NL	Office	135
TD Place	St. John's, NL	Office	94
Fortis Building	St. John's, NL	Office	83
Multiple Office	St. John's, NL	Office and Retail	75
Millbrook Mall	Corner Brook, NL	Retail	118
Fraser Mall	Gander, NL	Retail	99
Marystown Mall	Marystown, NL	Retail	87
Fortis Tower	Corner Brook, NL	Office	69
Viking Mall	St. Anthony, NL	Retail	69
Maritime Centre	Halifax, NS	Office and Retail	564
Brunswick Square	Saint John, NB	Office and Retail	512
Kings Place	Fredericton, NB	Office and Retail	292
Blue Cross Centre	Moncton, NB	Office and Retail	324
Delta Regina	Regina, SK	Office	52
Total			**2,761**

Revenue per available room, at the Hospitality Division of Fortis Properties, decreased for the first time in 14 years to $76.55 in 2009 from $80.39 in 2008. National revenue per available room declined 12.3 per cent for 2009 compared to 2008. The decrease was the result of lower average occupancy in 2009 mainly due to the impact of the economic downturn, partially offset by an increase in average room rates. Average occupancy for 2009 was 62.8 per cent down from the 66.9 per cent achieved in 2008, while the average daily room rate increased to $121.98 in 2009 up from $120.23 in 2008.

In April 2009, Fortis Properties acquired the Holiday Inn Select Windsor in Ontario. The hotel has 214 rooms and 14,000 square feet of meeting and banquet space.

The hotels owned and managed by Fortis Properties are summarized as follows.

Fortis Properties Hotels			
Hotels	**Location**	**Number of Guest Rooms**	**Conference Facilities** *(000's square feet)*
Delta St. John's	St. John's, NL	403	21
Holiday Inn St. John's	St. John's, NL	252	11
Sheraton Hotel Newfoundland	St. John's, NL	301	16
Mount Peyton	Grand Falls-Windsor, NL	148	4
Greenwood Inn Corner Brook	Corner Brook, NL	102	5
Four Points by Sheraton Halifax	Halifax, NS	177	12
Delta Sydney	Sydney, NS	152	6
Delta Brunswick	Saint John, NB	254	18
Holiday Inn Kitchener-Waterloo	Kitchener-Waterloo, ON	184	13
Holiday Inn Peterborough	Peterborough, ON	153	7
Holiday Inn Sarnia	Point Edward, ON	217	11
Holiday Inn Cambridge	Cambridge, ON	143	7
Holiday Inn Select Windsor	Windsor, ON	214	14
Greenwood Inn Calgary	Calgary, AB	210	9
Greenwood Inn Edmonton	Edmonton, AB	224	8
Greenwood Inn Winnipeg	Winnipeg, MB	213	10
Ramada Hotel & Suites Lethbridge	Lethbridge, AB	119	5
Holiday Inn Express and Suites Medicine Hat	Medicine Hat, AB	93	1
Best Western Medicine Hat	Medicine Hat, AB	122	-
Holiday Inn Express Kelowna (1)	Kelowna, BC	190	5
Delta Regina	Regina, SK	274	24
Total		**4,145**	**207**

(1) *Includes an additional 70 rooms and approximately 4,500 square feet of meeting space associated with an expansion of the hotel completed in February 2010*

Human Resources

As at December 31, 2009, Fortis Properties employed approximately 2,300 full-time equivalent employees, approximately 50 per cent of whom are represented by unions listed in the following table.

Fortis Properties Unions			
Property	**Union**	**Expiry of Agreement**	**Number of Unionized Employees**
Holiday Inn St. John's	CAW	August 31, 2012	52
Delta St. John's	UFCW	December 31, 2009 (1)	255
Greenwood Inn Corner Brook	CAW	March 11, 2010	43
East Side Mario's St. John's	CAW	July 31, 2010	100
Delta Sydney	CAW	September 30, 2011	81
Delta Brunswick & Brunswick Square	USW	June 10, 2010	150
Delta Regina	CEP	November 30, 2010	171
St. John's Real Estate	IBEW	April 17, 2010	11
Sheraton Hotel Newfoundland	CAW	March 31, 2011	180
Holiday Inn Select Windsor	UFCW	April 30, 2010	52
Mount Peyton	UFCW	December 1, 2011	54
Total			**1,149**

(1) *Collective bargaining is expected to begin before the end of the second quarter of 2010.*

4.0 REGULATION

The nature of regulation and summary of material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities are summarized as follows:

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2008	2009	2010	Supportive Features
						Future or Historical Test Year Used to Set Customer Rates
			ROE			COS/ROE
TGI	BCUC	40 [(1)]	8.62	8.47 (pre-July 1, 2009) 9.50 (post-July 1, 2009)	9.50	TGI: 50/50 sharing of earnings above or below the allowed ROE under a PBR mechanism that expired on December 31, 2009
TGVI	BCUC	40	9.32	9.17 (pre-July 1, 2009) 10.00 (post-July 1, 2009)	10.00	ROEs established by the BCUC, effective July 1, 2009, as a result of a cost of capital decision in 2009. Previously, the allowed ROEs were set using an automatic adjustment formula tied to long-term Canada bond yields.
						Future Test Year
FortisBC	BCUC	40	9.02	8.87	9.90	COS/ROE PBR mechanism for 2009 through 2011: 50/50 sharing of earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE – excess to deferral account ROE established by the BCUC, effective January 1, 2010, as a result of a cost of capital decision in 2009. Previously, the allowed ROE was set using an automatic adjustment formula tied to long-term Canada bond yields.
						Future Test Year
FortisAlberta	AUC	41 [(2)]	8.75	9.00	9.00	COS/ROE ROE established by the AUC, effective January 1, 2009, as a result of a generic cost of capital decision in 2009. Previously, the allowed ROE was set using an automatic adjustment formula tied to long-term Canada bond yields.
						Future Test Year
Newfoundland Power	PUB	45	8.95 +/- 50 bps	8.95 +/- 50 bps	9.00 +/- 50 bps	COS/ROE ROE for 2010 established by the PUB. Except for 2010, the allowed ROE is set using an automatic adjustment formula tied to long-term Canada bond yields.
						Future Test Year
Maritime Electric	IRAC	40	10.00	9.75	9.75 [(3)]	COS/ROE
						Future Test Year
FortisOntario	OEB Canadian Niagara Power	40 [(4)]	9.00	8.01	9.75 [(5)]	Canadian Niagara Power – COS/ROE
	Algoma Power	50	N/A	8.57	9.75	Algoma Power – COS/ROE and subject to Rural Rate Protection Subsidy program
	Franchise Agreement Cornwall Electric					Cornwall Electric - Price cap with commodity cost flow through
						Canadian Niagara Power – 2004 historical test year for 2008; 2009 test year beginning in 2009 Algoma Power – 2007 historical test year for 2009; 2010 test year for 2010
			ROA			Four-year COS/ROA agreements
Belize Electricity	PUC	N/A	10.00	10.00	- [(6)]	Additional costs in the event of a hurricane would be deferred and the Company may apply for future recovery in customer rates.
						Future Test Year
Caribbean Utilities	ERA	N/A	9.00 - 11.00	9.00 - 11.00	7.75 - 9.75	COS/ROA Rate-cap adjustment mechanism based on published consumer price indices Under the new T&D licence, the Company may apply for a special additional rate to customers in the event of a disaster, including a hurricane.
						Historical Test Year
Fortis Turks and Caicos	Utilities make annual filings with the Energy Commission	N/A	17.50 [(7)]	17.50 [(7)]	17.50 [(7)]	COS/ROA If the actual ROA is lower than the allowed ROA, due to additional costs resulting from a hurricane or other event, the Company may apply for an increase in customer rates in the following year.
						Future Test Year

(1) Effective January 1, 2010. For 2008 and 2009, the allowed deemed equity component of the capital structure was 35 per cent.
(2) Effective January 1, 2009. For 2008, the allowed deemed equity component of the capital structure was 37 per cent.
(3) Subject to regulatory approval
(4) Effective May 1, 2010. For 2009, effective May 1, the allowed deemed equity component of the capital structure was 43.3 per cent.
(5) Subject to Canadian Niagara Power filing a full cost of service application in 2010
(6) Allowed ROA to be settled once regulatory matters are resolved
(7) Amount provided under licence. Actual ROAs achieved in 2008 and 2009 were materially lower than the ROA allowed under the licence due to significant investment occurring at the utility.

Material Regulatory Decisions and Applications	
Regulated Utility	**Summary Description**
TGI/TGVI	• Every three months TGI and TGVI review natural gas and propane commodity rates with the BCUC in order to ensure the flow-through rates charged to customers are sufficient to cover the cost of purchasing natural gas and propane, while mid-stream rates are reviewed by the BCUC annually in December. As approved by the BCUC, the commodity rate for natural gas was unchanged for most customers and the commodity rate for propane and the mid-stream rate for natural gas decreased, all effective January 1, 2009. Effective April 1, 2009, the BCUC approved decreases in the commodity rates for natural gas and propane. Effective July 1, 2009, the BCUC approved the commodity rate for natural gas as unchanged for customers in most service regions and approved an increase in the commodity rate for propane for customers in Revelstoke. Effective October 1, 2009, the BCUC approved a decrease in commodity rates for natural gas for customers in the Lower Mainland, Fraser Valley and Interior service areas. Effective January 1, 2010, the BCUC approved an increase in mid-stream rates for natural gas and kept commodity rates for natural gas unchanged for customers in the Lower Mainland, Fraser Valley, Interior, North and the Kootenay service areas. The BCUC also approved an increase in commodity rates for propane for customers in Revelstoke, an increase in commodity rates for natural gas for customers in Fort Nelson and a decrease in commodity rates for natural gas for customers in Whistler, effective January 1, 2010. • In December 2008, the BCUC approved a basic customer delivery rate increase of approximately 6 per cent at TGI and approved basic customer delivery rate increases of up to 5 per cent at TGVI based on customer rate class. Basic customer delivery rates for 2009 reflected the decrease in the allowed ROE for 2009 to 8.47 per cent at TGI and to 9.17 per cent at TGVI, resulting from the application of ROE automatic adjustment formulas. • In March 2009, TGI received approval for its application with the BCUC to perform extensive rehabilitation of certain underwater transmission pipeline crossings of the South Arm of the Fraser River, serving Vancouver and Richmond. The project is expected to be completed in 2010 for a total cost of approximately $27 million. • In April 2009, TGI received approval from the BCUC for its new $41.5 million Energy Efficiency and Conservation Program to provide customers with enhanced tools and incentives to manage their natural gas consumption, reduce their energy costs and lower their greenhouse gas emissions. The program began in summer 2009. • In June 2009, the BCUC approved TGI's application requesting to sell liquefied natural gas as a transportation fuel source for fleet vehicles. • Effective June 1, 2009, the BCUC approved an average 12 per cent decrease in basic customer delivery rates at TGWI. Effective July 1, 2009, the BCUC also approved an approximate 10 per cent decrease in commodity rates at TGWI. • In November and December 2009, the BCUC approved: (i) NSAs pertaining to the 2010 and 2011 Revenue Requirements Applications for TGI and TGVI; (ii) an increase in the deemed equity component of TGI's total capital structure, effective January 1, 2010, to 40 per cent from 35 per cent; (iii) an increase in TGI's allowed ROE, effective July 1, 2009, to 9.50 per cent from 8.47 per cent; and (iv) an increase in the allowed ROE to 10.00 per cent, effective July 1, 2009, from 9.17 per cent for each of TGVI and TGWI. In its decision on the Return on Equity and Capital Structure Application, the BCUC maintained TGI as a benchmark utility for calculating the allowed ROE for certain utilities regulated by the BCUC. The BCUC also determined that the former automatic adjustment formula used to establish the ROE annually will no longer apply and the allowed ROEs as determined in the BCUC decision will apply until reviewed further by the BCUC. The BCUC-approved NSA for TGI did not include a provision to allow the continued use of a PBR mechanism after the expiry, on December 31, 2009, of TGI's previous PBR agreement. The approved mid-year rate base at TGI is approximately $2,540 million for 2010 and $2,634 million for 2011, and the approved mid-year rate base at TGVI is approximately $555 million for 2010 and $729 million for 2011. The overall impact on customer rates, including the effect of changes in the commodity and/or mid-stream rates for natural gas and/or propane, effective January 1, 2010, was: (i) an increase of approximately 10 per cent for residential customers in the Lower Mainland, Fraser Valley, Interior, North and the Kootneys; (ii) an increase of approximately 16 per cent for residential customers in Revelstoke; (iii) a decrease of approximately 12 per cent for customers in Whistler; and (iv) an increase of approximately 8 per cent for customers in Fort Nelson. Customer rates for TGVI's sales customers will remain unchanged for the two-year period beginning January 1, 2010, as provided in the BCUC-approved NSA for TGVI. • In June 2009, TGI filed an application with the BCUC requesting the in-sourcing of core elements of its customer care services and implementation of a new customer information system. Two new call centres and the customer information system are expected to be in place effective January 2012 at a total expected project cost of approximately $116 million, including the deferral of certain operating and maintenance expenses. The application was approved in February 2010, upon the Company accepting a cost-risk sharing condition, whereby the Company would share equally with customers any costs or savings outside a band of plus or minus 10 per cent of the approved total project cost.
FortisBC	• In December 2008, the BCUC approved the Company's 2009 Revenue Requirements Application, resulting in a general customer rate increase of 4.6 per cent, effective January 1, 2009. The customer rate increase was primarily the result of the Company's ongoing investment in electrical infrastructure and increasing power purchase prices driven by customer growth and increased electricity demand. Rates for 2009 reflected an allowed ROE of 8.87 per cent as a result of the application of the ROE automatic adjustment formula. The approval of the 2009 Revenue Requirements Application also included an extension of the PBR mechanism for the years 2009 through 2011 under terms similar to the previous PBR agreement, except annual gross operating and maintenance expenses, before capitalized overhead, will be set by a formula incorporating customer growth and inflation, i.e., the 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 is to be added to the PIF, which effectively caps the CPI at 3 per cent. • In February 2009, the BCUC issued its decision on FortisBC's 2009 and 2010 Capital Expenditure Plan. Total gross capital expenditures of $165 million were approved for 2009 and $156 million for 2010. • In August 2009, FortisBC applied for and received BCUC approval for a 2.2 per cent increase in customer rates, effective September 1, 2009. The increase was due to higher power purchase costs being charged to the Company by BC Hydro.

Material Regulatory Decisions and Applications (cont'd)	
Regulated Utility (cont'd)	**Summary Description (cont'd)**
FortisBC (cont'd)	• In December 2009, the BCUC approved an NSA pertaining to FortisBC's 2010 Revenue Requirements Application. The result was a general customer electricity rate increase of 6.0 per cent, effective January 1, 2010. The rate increase was primarily the result of the Company's ongoing investment in infrastructure, increasing power supply costs and the higher cost of capital. FortisBC's allowed ROE has increased to 9.90 per cent, effective January 1, 2010, from 8.87 per cent in 2009 as a result of the BCUC decision to increase the allowed ROE of TGI, the benchmark utility in British Columbia. The BCUC-approved NSA assumes a mid-year rate base of approximately $975 million for 2010.
FortisAlberta	• In December 2008, FortisAlberta received regulatory approval for its 2009 distribution rates to recover approved distribution costs. The result was a distribution rate increase of 8.6 per cent, effective January 1, 2009. The rate increase was slightly higher than the rate increase of 7.3 per cent contemplated in the 2008/2009 NSA, due to the deferred recovery in customer rates in 2009 of the increase in the allowed ROE to 8.75 per cent in 2008. The approved rates for 2009 also reflected the impact of the Company's union agreement, which was settled after the 2008/2009 NSA was approved. • In June 2009, FortisAlberta filed a comprehensive two-year Distribution Revenue Requirements Application for 2010 and 2011. The application forecasts a mid-year rate base of approximately $1,538 million for 2010 and $1,724 million for 2011. The expected impact on the distribution component of customer rates is an average increase of 13.3 per cent for 2010 and 14.9 per cent for 2011, before considering the impact of the increase in the allowed ROE and the deemed equity component of the total capital structure, as per the AUC Generic Cost of Capital Decision. The incremental effect of the final approved 2009 ROE and capital structure, as described below, is expected to be collected in customer electricity rates in 2010. New customer electricity rates to be established for 2010 will reflect an allowed ROE of 9.00 per cent on a deemed equity component of the total capital structure of 41 per cent. FortisAlberta anticipates a regulatory decision by the AUC to be received in spring 2010 with final customer electricity rates anticipated to take effect in late 2010 or early 2011. An interim approval of customer electricity rates by the AUC has resulted in an overall 7.5 per cent average increase in base customer distribution electricity rates at FortisAlberta, effective January 1, 2010. • In November 2009, the AUC issued its decision on the 2009 Generic Cost of Capital Proceeding, establishing a generic allowed ROE for all Alberta utilities it regulates of 9.00 per cent for each of 2009 and 2010. The allowed ROE of 9.00 per cent is up from 8.61 per cent that the former ROE automatic adjustment formula would have provided for FortisAlberta in 2009. The ROE automatic adjustment formula will no longer apply until reviewed further by the AUC. The AUC also increased the deemed equity component of FortisAlberta's total capital structure to 41 per cent from 37 per cent, effective January 1, 2009. Two hundred basis points of the increase in the equity component of the capital structure reflected the effects of FortisAlberta having become a non-taxable utility for rate-setting purposes. The AUC also ordered that the generic allowed ROE for Alberta utilities that it regulates, including FortisAlberta, be established on an interim basis for 2011 at 9.00 per cent. The establishment of an interim ROE level was chosen because the AUC was not prepared to reimpose an adjustment formula without the opportunity to assess changes in the capital markets and to reconsider the types of factors that should be built into a formula.
Newfoundland Power	• In November 2008, the PUB approved, as filed, the Company's 2009 Capital Budget Application for approximately $62 million, with approximately half of the proposed capital expenditures relating to construction and capital maintenance of the electricity system. During the third quarter of 2009, Newfoundland Power filed supplemental applications to its 2009 Capital Budget Application, requesting an additional approximate $2 million in capital spending, which were approved by the PUB. • The Company's allowed ROE of 8.95 per cent for 2009 remained unchanged from 2008 and, consequently, did not impact customer electricity rates for 2009. • Effective July 1, 2009, the PUB approved an overall average decrease in customer electricity rates of approximately 6.6 per cent, reflecting the flow through to customers, by operation of the Rate Stabilization Account, of variances in the cost of fuel used to generate electricity that Newfoundland Hydro sells to Newfoundland Power. The decrease in customer electricity rates had no impact on Newfoundland Power's earnings in 2009. • In November 2009, the Company's 2010 Capital Budget Application totalling approximately $65 million was approved by the PUB. • In December 2009, the PUB issued a decision on Newfoundland Power's 2010 General Rate Application, resulting in an overall average increase in basic customer electricity rates of approximately 3.5 per cent, effective January 1, 2010, including the impact of an increase in the allowed ROE to 9.00 per cent from 8.95 per cent in 2009, as set by the PUB for 2010. The PUB decision assumes a mid-year rate base of approximately $869 million for 2010. The PUB also ordered that Newfoundland Power's allowed ROE for each of 2011 and 2012 be determined using the ROE automatic adjustment formula. The ROE automatic adjustment formula is subject to a review by the PUB in the first quarter of 2010.
Maritime Electric	• In March 2009, IRAC approved Maritime Electric's 2009 Rate Application, which resulted in an increase in the base amount of energy-related costs being expensed and collected from customers and recorded in revenue through the basic rate component of customer billings, effective April 1, 2009. The increase in the reference cost of energy in basic rates from 6.73 cents per kWh to 7.7 cents per kWh resulted in a decrease in the amount of energy costs collected from customers through the operation of the ECAM. Additionally, IRAC approved the deferral of Point Lepreau replacement energy costs for 2009 and an increase in the amortization period of the ECAM to 12 months, effective April 1, 2009. IRAC also approved, as filed, a maximum allowed ROE of 9.75 per cent for 2009, down from an allowed ROE of 10.00 per cent for 2008. The overall impact on residential customer electricity rates for 2009 was an increase of 5.3 per cent based on average consumption of 650 kWh per month. • In September 2009, NB Power announced that the refurbishment of Point Lepreau was behind schedule with the target date for electricity to be generated again delayed until early 2011. The Point Lepreau reactor was originally scheduled to restart October 1, 2009. • In October 2009, Maritime Electric received regulatory approval, as filed, of its 2010 Capital Budget Application totalling $22 million, before customer contributions. • In October 2009, Maritime Electric received regulatory approval of the extension of its energy purchase agreement with NB Power to December 31, 2010. The agreement, originally entered into in April 2008, was set to expire in September 2009 when Point Lepreau was to return to service. Delays in the refurbishment and resulting return to service date of Point Lepreau required an extension of the energy purchase agreement.

Material Regulatory Decisions and Applications (cont'd)	
Regulated Utility (cont'd)	**Summary Description (cont'd)**
Maritime Electric (cont'd)	• In January 2010, Maritime Electric filed an application with IRAC: (i) providing a report on the impact of the rebasing of the ECAM deferral account in 2009 and requesting an increase in the reference cost of energy in basic rates from 7.7 cents per kWh to 9.4 cents per kWh, effective April 1, 2010, and from 9.4 cents per kWh to 9.6 cents per kWh, effective April 1, 2011; (ii) requesting that the replacement energy costs incurred during the refurbishment of Point Lepreau be amortized over a period of 25 years, representing the extended life of the unit; and (iii) requesting an allowed ROE of 9.75 per cent for both 2010 and 2011, unchanged from 2009.
FortisOntario	• In August 2009, the OEB issued its Rate Order for Fort Erie and Gananoque, approving final distribution rate increases using 2009 as a forward test year, effective May 1, 2009, of 5.1 per cent and 11.7 per cent, respectively, with impact on customer billings commencing September 1, 2009. Foregone revenue from May 1, 2009 through August 31, 2009 will be recovered from customers through a rate rider in effect from September 1, 2009 through April 30, 2010. The Rate Order confirmed a deemed capital structure containing 43.3 per cent equity, approved an allowed ROE of 8.01 per cent for 2009 and approved all forecast capital expenditures and significantly all forecast operating expenses, as filed. The approved rate increases were primarily driven by the impact of distribution system upgrades. • In September and October 2009, the OEB held a stakeholder conference to determine whether current economic and financial market conditions warranted an adjustment to any cost of capital. In December 2009, the OEB issued its *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*. Based on current economic indicators, a preliminary allowed ROE has been set at 9.75 per cent for utilities in Ontario regulated by the OEB. The ROE formula has been refined to reduce sensitivity to changes in long-term Canada bond yields and includes an additional factor for utility bond spreads. The updated allowed ROE will come into effect for the setting of customer rates beginning in 2010 by way of a cost of service application. • In October and November 2009, FortisOntario filed Third-Generation IRM electricity distribution rate applications for harmonized rates for Fort Erie and Gananoque and rates for Port Colborne, effective May 1, 2010, based on a deemed capital structure containing 40 per cent equity. In non-rebasing years, customer electricity rates are set using inflationary factors less an efficiency target under the OEB's Third-Generation IRM. • In October 2009, the OEB issued its Rate Order for Port Colborne, approving a final electricity rate increase using 2009 as a forward test year, effective May 1, 2009, of 8.4 per cent, with impact on customer billings commencing November 1, 2009. Foregone revenue from May 1, 2009 through October 31, 2009 will be recovered from customers through a rate rider in effect from November 1, 2009 through April 30, 2011. The Rate Order confirmed a deemed capital structure containing 43.3 per cent equity and approved an allowed ROE of 8.01 per cent for 2009. • FortisOntario expects to file a new electricity rate application for Algoma Power during the first half of 2010 for rates effective July 1, 2010, using 2010 as a forward test year and an allowed ROE of 9.75 per cent.
Belize Electricity	• In June 2008, the PUC issued its Final Decision on Belize Electricity's 2008/2009 Rate Application, which rejected most of the recommendations of a PUC-appointed Independent Expert engaged to review the PUC's Initial Decision on Belize Electricity's 2008/2009 Rate Application and failed to increase the overall average electricity rate, as requested in the application. The PUC also ordered a BZ$36 million retroactive adjustment associated with Belize Electricity's prior years' financial results. The adjustment, in substance, represented the disallowance of previously incurred fuel and purchased power costs. The PUC also reduced Belize Electricity's targeted allowed ROA to 10 per cent from 12 per cent through a reduction in the VAD component of the average electricity rate. As a direct result of the June 2008 Final Decision, Belize Electricity recorded an $18 million (BZ$36 million) charge ($13 million of which was the Corporation's share) to energy supply costs during the second quarter of 2008. The Final Decision does not affect the Corporation's hydroelectric generation operations conducted in BECOL. • The Final Decision also proposed the use of an automatic mechanism, to be finalized by the PUC, to adjust monthly, on a two-month lag basis, the cost of power component of the rate to reflect actual costs of power. The automatic adjustment mechanism, which was retroactively effective September 1, 2008, allows for the recovery from, or refund to, customers of the actual cost of power that varies from a reference cost of power by more than a threshold of 10 per cent. • In February 2009, the PUC amended the Final Decision on Belize Electricity's 2008/2009 Rate Application (the "Amendment"), effective for the period from January 1, 2009 through June 30, 2009. The Amendment provides for an increase in the VAD component of the average electricity rate to allow Belize Electricity to earn a targeted allowed ROA of 12 per cent but reduces the reference cost of power component of the average electricity rate, due to an overall decline in the cost of power. The Amendment, therefore, allows for an overall decrease in the average electricity rate from BZ44.1 cents per kWh to BZ37.5 cents per kWh. The Amendment also provides for a lower regulated asset value upon which the allowed ROA is calculated, while increasing operating expenses by the same amount, and reduces depreciation, taxes and fees and the related revenue requirement. • In April 2009, Belize Electricity filed its Annual Tariff Review Application for the annual tariff period from July 1, 2009 to June 30, 2010 (the "2009/2010 Rate Application") proposing a 6 per cent decrease in the average electricity rate, as well as a reversal of the BZ$36 million charge described above. The PUC has not accepted the 2009/2010 Rate Application on the grounds that an Annual Tariff Review Proceeding is not in effect. • Changes made in electricity legislation by the Government of Belize and the PUC, and the PUC's June 2008 Final Decision and the Amendment, which were based on the changed legislation, have been judicially challenged by Belize Electricity in several proceedings. The judicial process is ongoing with interim rulings, judgments and appeals. The timing or likely final outcome of the proceedings is indeterminable at this time. The Supreme Court of Belize issued an injunction against the Amendment until Belize Electricity's appeal of the June 2008 Final Decision has been heard in court. The court appeal of the June 2008 Final Decision was called in early October 2009 but, after considering some preliminary matters, the trial judge postponed the case for a date to be determined. In addition, Belize Electricity's appeal of the Supreme Court of Belize's previous decision to uphold certain changes made in electricity legislation by the Government of Belize and the PUC was dismissed in June 2009. • In June 2009, the Government of Belize issued a statutory instrument purporting to declare providers of electricity generation and water services, including BECOL, as public utility providers within the meaning of the *Public Utilities Commission Act* as of May 1, 2009. Fortis continues to assess the statutory instrument and its impact on previously negotiated and PUC-approved power purchase agreements.

Material Regulatory Decisions and Applications (cont'd)	
Regulated Utility (cont'd)	**Summary Description (cont'd)**
Caribbean Utilities	• In March 2009, the ERA approved the Company's 2009 CIP of US$48 million. • In April 2009, Caribbean Utilities submitted its bid to install 16 MW of generation in May 2012 and another 16 MW of generation in May 2013. There was one other bidder for the 32 MW of generation. In September 2009, based on economic conditions and revised medium-term future load growth projections by Caribbean Utilities, the ERA cancelled its 32 MW capacity-expansion solicitation. Caribbean Utilities and the ERA will continue to monitor growth indicators and revise forecasts as necessary. A new solicitation may occur at such time as there are indicators of a future need for additional capacity. • The ERA approved a 2.4 per cent increase in basic customer electricity rates, effective June 1, 2009, in accordance with Caribbean Utilities' T&D licence. • In February 2010, the ERA approved Caribbean Utilities' 2010-2014 CIP at US$98 million for non-generation expansion expenditures. The 2010-2014 CIP submitted by Caribbean Utilities to the ERA in October 2009 totalled US$157 million, which included US$59 million for estimated costs associated with future generation expansion that is expected to be solicited.
Fortis Turks and Caicos	• In March 2009, Fortis Turks and Caicos submitted its 2008 annual regulatory filing outlining the Company's performance in 2008 and its capital expansion plans for 2009.

5.0 ENVIRONMENTAL MATTERS

The Corporation and its Canadian subsidiaries are subject to federal, provincial and municipal laws, regulations and guidelines relating to the protection of the environment including, but not limited to, wildlife, water and land protection and the proper storage, transportation, recycling and disposal 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 their commencement.

Several key Canadian federal environmental laws and regulations affecting the operations of the Corporation's Canadian subsidiaries include, but are not limited to, the: (i) *Canadian Environmental Assessment Act;* (ii) *Canadian Environmental Protection Act*; (iii) *Transportation of Dangerous Goods Act and Regulations*; (iv) *Hazardous Product Act*; (v) *Canada Wildlife Act*; (vi) *Navigable Waters Protection Act*; (vii) *Canada National Parks Act*; (viii) *Fisheries Act; (ix) Canada Water Act; (x) National Emission Guidelines for Stationary Combustion Turbines; (xi) National Fire Code of Canada; (xii) Pest Control Products Act and Regulations; (xiii) Storage of PCB Material Regulations; (xiv) Canadian Species at Risk Act; and (xv) Ozone Depleting Substances Regulations.*

There are many Canadian provincial and municipal laws, regulations and guidelines that address similar environmental risks as the federal laws, regulations and guidelines, but at a local level.

In British Columbia, the *Carbon Tax Act* and *Greenhouse Gas Reduction Targets Act* specifically affect, or may potentially affect, the operations of the Terasen Gas companies and FortisBC as is described later in this section.

While there are environmental laws, regulations and guidelines affecting the Corporation's operations in Grand Cayman, Turks and Caicos, and Belize, they are less extensive than the laws, regulations and guidelines in Canada.

Environmental risks affecting the Corporations' utility operations include, but are not limited to: (i) hazards associated with the storage and handling of large volumes of fuel at fuel-powered electricity generating plants, including leeching of the fuel into the ground and nearby watershed areas; (ii) risk of spilling or leaking petroleum-based products, including PCB-contaminated oil, which are used in the cooling and lubrication of transformers, capacitors and other electrical equipment; (iii) greenhouse gas emissions, including natural gas and propane leaks and spills and emissions from the combustion of fuel required to generate electricity; (iv) risk of fire; (v) risk of contamination of air, soil or land associated with the improper handling, storage, transportation and disposal of other hazardous substances; (vi) risk of disruption to vegetation; (vii) risk of contamination of soil and water near chemically treated poles; (viii) risk of disruption to fish, animals and their habitat as a result of the creation of artificial water flows and levels associated with hydroelectric water storage and utilization; and (ix) risk of responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner.

The key focus of the utilities is to provide reliable cost-effective service with full regard for the safety of employees and the public while operating in an environmentally responsible manner. A focus on safety and the environment is, therefore, an integral and continuing component of the Corporation's operating activities. The environmental policies vary among the Corporation's utilities depending on the specific environmental laws, regulations and guidelines applicable to their operations and jurisdiction. However, the policies are implemented and reinforced through the use of environmental management systems. Common elements of the utilities' environmental management systems include: (i) regular inspections of fuel- and oil-filled equipment in order to identify and correct for potential spills, and spill response systems to ensure that all spills are addressed, and the associated cleanup is conducted in a prompt and environmentally responsible manner; (ii) greenhouse gas emissions management; (iii) procedures for handling, transporting, storing and disposing of hazardous substances, including chemically treated poles, asbestos, lead and mercury; (iv) programs to mitigate fire-related incidents; (v) programs for the management and/or elimination of PCBs; (vi) vegetation management programs; (vii) training and communicating of environmental policies to employees to ensure work is conducted in an environmentally responsible manner; (viii) review of work practices that affect the environment; (ix) waste management programs; (x) environmental emergency response procedures; (xi) environmental site assessments; and (xii) environmental incident reporting procedures.

The Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario have developed their respective environmental management systems consistent with the guidelines of ISO 14001, an internationally recognized standard for environmental management systems. Caribbean Utilities operates an environmental management system associated with its generation operations, which is ISO 14001 certified, and uses an environmental management system for its transmission and distribution operations, which is consistent with ISO 14001 guidelines. Belize Electricity has implemented an environmental management system with the intention of it becoming consistent with ISO 14001 guidelines by the end of 2010. Fortis Turks and Caicos plans to have an environmental management system fully implemented by 2012, which will be consistent with ISO 14001 guidelines. As part of their respective environmental management system, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor performance. External and/or internal audits of the environmental management systems are performed on a periodic basis. Based on audits completed in 2009, the environmental management systems continue to be effective and materially consistent with ISO 14001 guidelines.

Environmental risks associated with the Corporation's non-regulated generation operations are either addressed by environmental management systems of the Corporation's regulated electric utilities or by environmental practices and procedures followed by Fortis Properties.

For the Corporation's regulated gas utilities, air emissions management is the main environmental concern primarily due to the uncertainties relating to emerging federal and provincial greenhouse gas regulations. While governmental policy direction is unfolding, it remains to be determined to what extent a greenhouse air emissions cap will impact these utilities. To help mitigate this uncertainty, the Terasen Gas companies participate in sectoral and industry groups to develop the emerging regulation. In addition, TGI was an active participant in Canada's Voluntary Climate Change Challenge and Registry and, its successor, the Canadian Greenhouse Gas Challenge Registry.

Recent updates to the Government of British Columbia's Energy Plan and greenhouse gas reduction targets present risks and opportunities to the Terasen Gas companies and, to a lesser degree, FortisBC. The *Greenhouse Gas Reduction Targets Act* mandates a province-wide reduction in greenhouse gases of 33 per cent from 2007 levels by 2010. This is coupled with mandates for all new electricity generation to be net carbon neutral, and for British Columbia to be electrically self-sufficient by 2016.

Energy and emissions policies in British Columbia also present a number of opportunities. The policies have created incentives to expand Terasen's deployment of renewable energy, such as biogas, and to expand the Company's Energy Efficiency and Conservation Program. Additionally, the introduction of the *Carbon Tax Act* improves the position of natural gas relative to other fossil energy, as the tax is based on the amount of carbon dioxide equivalent emitted per unit energy. Natural gas, therefore, has a lower tax rate than oil or coal products.

British Columbia is a participant in the Western Climate Initiative. The participants, consisting of several states and provinces, plan to implement a cap-and-trade program to reduce greenhouse gas emissions. The program begins on January 1, 2012. Terasen expects to have two facilities covered under this program; TGI and TGVI . The specific details outlining which facilities will be captured are dependent on what types of emissions are covered, and how individual facilities will be defined under cap and trade legislation. The cap and trade program will 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 amounts. While allowance costs are based on market prices that have little clarity at present, it appears likely that these facilities will be net purchasers of allowances over the near and medium terms. Allowances will likely be issued to mirror the emission reduction mandate of the Government of British Columbia, such that emissions will need to be reduced by 33 per cent over 2007 amounts by 2020.

The key environmental risks affecting the Corporation's hospitality and real estate operations include, but are not limited to: (i) risk of asbestos and urea-formaldehyde contamination in buildings; (ii) risk of release of ozone-depleting substances from air conditioning and refrigeration equipment; (iii) fuel tank leaks; and (iv) risk of responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. Fortis Properties is committed to meeting the requirements of environmental standards related to its hospitality and real estate operations. In assessing new properties, all buildings and hotels must meet environmental standards, including, but not limited to, the appropriate federal, provincial and municipal standards for asbestos, fuel storage, urea-formaldehyde and chlorofluorocarbon-based refrigerants in air conditioning and refrigerating equipment. This process is also applied to existing properties, ensuring environmental compliance by all facilities.

The Corporation has asset-retirement obligations as disclosed in the Notes to the 2009 consolidated financial statements of Fortis. However, liabilities with respect to these asset-retirement obligations have not been recorded in the Corporation's 2009 consolidated financial statements as they could not be reasonably estimated or were determined to be immaterial (including asset-retirement obligations associated with PCBs, asbestos and chemically treated poles) to the Corporation's consolidated results of operations, cash flows or financial position.

Costs associated with environmental protection initiatives (including the development, implementation and maintenance of environmental management systems), compliance with environmental laws, regulations and guidelines, and environmental damage did not materially affect the Corporation's consolidated results of operations, cash flows or financial position and, based on current laws, facts and circumstances, are not expected to have a material effect in the future. At the Corporation's regulated utilities, prudently incurred operating and capital costs associated with environmental protection initiatives, compliance with environmental laws, regulations and guidelines, and environmental damage are eligible for recovery in customer rates. The Corporation believes that it and its subsidiaries are materially compliant with environmental laws and regulations applicable to them in the various jurisdictions in which they operate.

For further information on the Corporation's environmental risk factors, refer to the "Risk Factors - Environmental Risks" section of this 2009 Annual Information Form.

6.0 RISK FACTORS

The following is a summary of the Corporation's significant business risks.

Regulatory Risk: The Corporation's key business risk is regulation. Each of the Corporation's regulated utilities is subject to some form of regulation that can affect future revenue and earnings. Management at each utility is responsible for working closely with its regulator and local government to ensure both compliance with existing regulations and the proactive management of regulatory issues.

Approximately 93 per cent of the Corporation's operating revenue was derived from regulated utility operations in 2009 (2008 - 93 per cent), while approximately 88 per cent of the Corporation's operating earnings, before corporate and other net expenses, were derived from regulated utility operations in 2009 (2008 - 83 per cent). The Corporation's regulated utilities are subject to the normal uncertainties faced by regulated entities, including approvals by the respective regulatory authority of gas and electricity rates that permit a reasonable opportunity to recover, on a timely basis, the estimated costs of providing services, including a fair rate of return on rate base and, in the case of Caribbean Utilities and Fortis Turks and Caicos, the continuation of licences. Generally, the ability of the utilities to recover the actual costs of providing services and to earn the approved ROEs and/or ROAs depends on achieving the forecasts established in the rate-setting processes. Upgrades of, and additions to, gas and electricity infrastructure require the approval of the regulatory authorities either through the approval of capital expenditure plans or regulatory approval of revenue requirements for the purpose of setting electricity and gas rates, which include the impact of capital expenditures on rate base and/or cost of service. There is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed. Capital cost overruns subject to such approvals might not be recoverable. In addition, there is no assurance that the regulated utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

Rate applications that establish revenue requirements may be subject to negotiated settlement procedures, as well as pursued through public hearing processes. There can be no assurance that rate orders issued will permit the Corporation's utilities to recover all costs actually incurred and to earn the expected rates of return. A failure to obtain acceptable rate orders may adversely affect the business carried on by the utilities, the undertaking or timing of proposed capital projects, ratings assigned by rating agencies, the issuance and sale of securities and other matters, which may, in turn, negatively affect the results of operations and financial position of the Corporation's utilities.

Although Fortis considers the regulatory frameworks in most of the jurisdictions it operates in to be fair and balanced, uncertainties do exist at the present time. The June 2008 regulatory decision related to Belize Electricity's 2008/2009 Rate Application and changes in electricity legislation made by the Government of Belize and the PUC create uncertainty in the regulatory regime and the rate-setting process in Belize and violate both established regulatory practice and contractual obligations made by the Government of Belize at the time Fortis made its initial investment in Belize Electricity.

Although all of the Corporation's regulated utilities currently operate under cost of service and/or rate of return on rate base methodologies, PBR and other rate-setting mechanisms, such as ROE automatic adjustment formulas, are also being employed to varying degrees. A discussion of the impact of changes in interest rates on allowed ROEs is provided in the "Risk Factors - Interest Rate Risk" section of this 2009 Annual Information Form.

TGI and FortisBC are regulated by the BCUC and have, from time to time, used PBR mechanisms. PBR mechanisms provide utilities an opportunity to earn returns in excess of the allowed ROEs determined by the regulator. The current PBR mechanism at FortisBC extends through 2011. Upon expiry of the PBR mechanism, there is no certainty as to whether a new PBR mechanism will be entered into or what the particular terms of any renewed PBR mechanism will be.

The PBR mechanism at TGI expired at the end of 2009 and the BCUC-approved rate settlement agreement reached at TGI pertaining to 2010 and 2011 revenue requirements did not provide for the continuation of a PBR mechanism after December 2009. Under the 2010 and 2011 rate settlement agreements reached at both TGI and TGVI, certain cost of service variances are subject to deferral account treatment and the balances are at the respective company's risk.

Operating and Maintenance Risks: The Terasen Gas companies are exposed to various operational risks, such as: pipeline leaks; accidental damage to, or fatigue cracks in, mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks; and any other accidents involving natural gas that could result in significant operational disruptions and/or environmental liability. The Terasen Gas companies maintain comprehensive facility risk assessment, pipeline integrity management and damage prevention programs and pipeline security systems as preventive measures to mitigate the risk of a pipeline failure or other loss of system integrity. The business of electricity transmission and distribution is also subject to operational risks including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. The infrastructure of the subsidiaries is also exposed to the effects of severe weather conditions and other acts of nature. In addition, a significant portion of the infrastructure is located in remote areas, which may make access difficult for repair of damage due to weather conditions and other acts of nature. The Terasen Gas companies and FortisBC operate facilities in a terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, avalanches and similar acts of nature. The Terasen Gas companies, FortisBC and, to a lesser extent, the Corporation's operations in the Caribbean, are subject to risk of loss from earthquakes. The Corporation and its subsidiaries have insurance that provides coverage for business interruption, liability and property damage, although the coverage offered by this insurance is limited. In the event of a large uninsured loss caused by severe weather conditions or other natural disasters, application will be made to the respective regulatory authority for the recovery of these costs through higher rates to offset any loss. However, there can be no assurance that the regulatory authorities would approve any such application in whole or in part. See the "Risk Factors - Insurance Coverage Risk" section of this 2009 Annual Information Form for a further discussion on insurance.

The Corporation's gas and electricity systems require ongoing maintenance, improvement and replacement. Accordingly, to ensure the continued performance of the physical assets, the utilities determine expenditures that must be made to maintain and replace the assets. If the systems are not able to be maintained, service disruptions and increased costs may be experienced. The inability to obtain regulatory approval to reflect in rates the expenditures the utilities believe are necessary to maintain, improve and replace assets; the failure by the utilities to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures, despite maintenance programs, could have a material effect on the operations of the utilities.

The Corporation's utilities continually develop capital expenditure programs and assess current and future operating and maintenance expenses that will be incurred in the ongoing operation of their gas and electricity systems. Management's analysis is based on assumptions as to cost of service and equipment, regulatory requirements, revenue requirement approvals and other matters, which involve some degree of uncertainty. If actual costs exceed regulator-approved capital expenditures, it is uncertain whether any 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 utilities.

Economic Conditions: Typical of utilities, economic conditions in the Corporation's service territories influence energy sales. Energy sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices and housing starts. Also, in the service territories in which the Terasen Gas companies operate, the level of new multi-family housing starts is continuing to outpace that of new single-family housing starts. Natural gas has a lower penetration rate in multi-family housing; therefore, growth in gas distribution volumes may be tempered. In the Caribbean, the level of, and fluctuations in, tourism and related activities, which are closely tied to economic conditions, influence electricity sales as they affect electricity demand of the large hotels and condominium complexes that are serviced by the Corporation's regulated utilities in that region.

Higher energy prices can result in reduced consumption by customers. Natural gas and crude oil exploration and production activities in certain of the Corporation's service territories are closely correlated with natural gas and crude oil prices. The level of these activities can influence energy demand, affecting local energy sales in some of the Corporation's service territories.

An extended decline in economic conditions would be expected to have the effect of reducing demand for energy over time. The regulated nature of utility operations, including various mitigating measures approved by regulators, helps to reduce the impact that lower energy demand, associated with poor economic conditions, may have on the utilities' earnings. However, a severe and prolonged downturn in economic conditions could materially affect the utilities, despite regulatory measures available to compensate for reduced demand. For instance, significantly reduced energy demand in the Corporation's service territories could reduce capital spending, which would, in turn, affect rate base and earnings' growth.

In addition to the impact of reduced energy demand, an extended decline in economic conditions could also impair the ability of customers to pay for gas and electricity consumed, thereby affecting the aging and collection of the utilities' trade receivables.

Fortis also holds investments in both commercial office and retail space and hotel properties. The hotel properties, in particular, are subject to operating risks associated with industry fluctuations and local economic conditions. Fortis Properties' real estate exposure to lease expiries averages approximately 9 per cent per annum over the next five years. Approximately 56 per cent of Fortis Properties' operating income was derived from hotel investments in 2009 (2008 - 57 per cent). Same-hotel revenue declined at Fortis Properties' Hospitality Division in 2009 from 2008 and organic revenue growth will continue to be challenged in 2010 as a result of the economic downturn and its impact on leisure and business travel and hotel stays. It is estimated that a 10 per cent decrease in revenue at the Hospitality Division would decrease annual basic earnings per common share of Fortis by approximately 2 cents.

Capital Resources and Liquidity Risk: The Corporation's financial position could be adversely affected if it, or one of its subsidiaries, 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 the financial position of the Corporation and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions. 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, as well as all anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to repay existing debt and fund capital expenditures.

The Corporation and its currently rated regulated utilities are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings affect the level of credit risk spreads on new long-term debt issues and on the Corporation's and its utilities' credit facilities. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease finance charges of the Corporation and its utilities. Also, a significant downgrade in the credit ratings of TGI or Terasen could trigger margin calls and other cash requirements under TGI's natural gas purchase and natural gas derivative contracts. Fortis and its regulated utilities do not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, the global financial crisis has placed increased scrutiny on rating agencies and rating agency criteria, which may result in changes to credit rating practices and policies.

Despite volatility in the global capital markets, the Corporation and its utilities have been successful at raising long-term capital at reasonable rates. However, continued volatility in the global capital markets may increase the cost, and affect the timing, of issuance of long-term capital by the Corporation and its utilities. While the cost of borrowing may increase, the Corporation and its utilities expect to continue to have reasonable access to capital in the near to medium terms. The cost of renewed and extended credit facilities may also increase going forward; however, any increase in interest expense and/or fees is not expected to materially impact the Corporation's consolidated financial results in 2010 as the majority of the total credit facilities have maturities between 2011 and 2013. As the Corporation's utilities are regulated under cost of service, any increased cost of borrowing at the utilities is eligible to be recovered in customer rates.

To help mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements. The committed credit facility at the Corporation is available for interim financing of acquisitions and for general corporate purposes.

Weather and Seasonality: The physical assets of the Corporation and its subsidiaries are exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed and are operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. At Newfoundland Power, exposure to climatic factors is addressed through the operation of a regulator-approved weather normalization reserve. The operation of this reserve mitigates year-to-year volatility in earnings that would otherwise be caused by variations in weather conditions. At TGI, a BCUC-approved rate stabilization account serves to mitigate the effect on earnings of volume volatility, caused principally by weather, by allowing TGI to accumulate the margin impact of variations in the actual versus forecast gas volumes consumed by customers.

At the Terasen Gas companies, weather has a significant impact on distribution volume, as a major portion of the gas distributed is ultimately used for space heating for residential customers. Because of gas-consumption patterns, the Terasen Gas companies normally generate quarterly earnings that vary by season and may not be an indicator of annual earnings. Most of the annual earnings of the Terasen Gas companies are generated in the first and fourth quarters.

Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather. In Canada, cool summers may reduce air-conditioning demand while less severe winters may reduce electric heating load. In the Caribbean, the impact of seasonal changes in weather on air-conditioning demand is less pronounced due to the less variable climatic conditions that prevail in the region. Significant fluctuations in weather-related demand for electricity could materially impact the operations, financial condition and results of operations of the electric utilities.

Despite preparation for severe weather, extraordinary conditions such as hurricanes and other natural disasters will always remain a risk to utilities. The Corporation uses a centralized insurance management function to create a higher level of insurance expertise and reduce its liability exposure.

The assets and earnings of Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos are subject to hurricane risk. Similar to other Fortis utilities, these companies manage weather risks through insurance on generation assets, business-interruption insurance and self-insurance on transmission and distribution assets. In Belize, additional costs in the event of a hurricane would be deferred and the Company may apply for future recovery in customer rates. Under its transmission and distribution licence, Caribbean Utilities may apply for a special additional customer rate in the event of a disaster, such as a hurricane. Fortis Turks and Caicos does not have a specific hurricane cost recovery mechanism; however, the Company may apply for an increase in customer rates in the following year if the actual ROA is lower than the allowed ROA due to additional costs resulting from a hurricane or other significant event.

Earnings from non-regulated generation assets are sensitive to rainfall levels but the geographic diversity of the Corporation's generation assets mitigates the risk associated with rainfall levels.

Commodity Price Risk: The Terasen Gas companies are exposed to commodity price risk associated with changes in the market price of natural gas. The companies employ a number of tools to reduce exposure to natural gas price volatility. These tools include purchasing gas for storage and adopting hedging strategies, which include a combination of both physical and financial transactions, to reduce price volatility and ensure, to the extent possible, that natural gas costs remain competitive with electricity rates. The use of natural gas derivatives effectively fixes the price of natural gas purchases. Activities related to the hedging of gas prices are currently approved by the BCUC and gains or losses effectively accrue entirely to customers. The operation of BCUC-approved rate stabilization accounts to flow through in customer rates the commodity cost of natural gas serves to mitigate the effect on earnings of natural gas cost volatility.

Most of the Corporation's regulated electric utilities are exposed to commodity price risk associated with changes in world oil prices, which affects the cost of fuel and purchased power. The risk is substantially mitigated by the utilities' ability to flow through to customers the cost of fuel and purchased power through basic rates and/or the use of rate-stabilization and other mechanisms, as approved by the various regulatory authorities. The ability to flow through to customers the cost of fuel and purchased power alleviates the effect on earnings of the variability in the cost of fuel and purchased power.

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of the cost of natural gas, fuel and purchased power will continue to exist in the future. An inability of the regulated utilities to flow through the full cost of natural gas, fuel and/or purchased power could materially affect the utilities' results of operations, financial position and cash flows.

Derivative Financial Instruments and Hedging: From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas commodity prices through the use of derivative financial instruments. The derivative financial instruments, such as interest rate swap contracts, foreign exchange future contracts and natural gas commodity swaps and options, are used by the Corporation and its subsidiaries only to manage risk and are not used or held for trading purposes. All derivative financial instruments must be measured at fair value. If a derivative financial instrument is designated as a hedging item in a qualifying cash flow hedging relationship, the effective portion of changes in fair value is recorded in other comprehensive income. Any change in fair value relating to the ineffective portion is recorded immediately in earnings. At the Terasen Gas companies, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a qualifying hedging relationship, and the amount recovered from customers in current rates is subject to regulatory deferral treatment to be recovered from, or refunded to, customers in future rates.

The Corporation's earnings from, and net investment in, its self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars or in a currency pegged to the US dollar. Belize Electricity's reporting currency is the Belizean dollar while the reporting currency of Caribbean Utilities, FortisUS Energy, BECOL and Fortis Turks and Caicos is the US dollar. The Belizean dollar is pegged to the US dollar at BZ$2.00=US$1.00. As at December 31, 2009, the Corporation's corporately held US$390 million (December 31, 2008 – US$403 million) long-term debt had been designated as a hedge of a portion of the Corporation's foreign net investments. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately held US dollar borrowings designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which are also recorded in other comprehensive income. As at December 31, 2009, the Corporation had approximately US$174 million (December 31, 2008 – US$119 million) in foreign net investments remaining to be hedged.

It is estimated that a 5 cent, or 5 per cent, increase (decrease) in the US dollar-to-Canadian dollar exchange rate from the exchange rate of 1.05, as at December 31, 2009, would increase (decrease) basic earnings per common share of Fortis by 1 cent in 2010.

Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar and Belizean dollar earnings' streams, where possible, through future US dollar borrowings, and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Interest Rate Risk: Generally, allowed rates of return for regulated utilities in North America are exposed to changes in the general level of long-term interest rates. The allowed rates of return are set either directly through automatic adjustment formulas or indirectly through regulatory determinations of what constitutes an appropriate rate of return on investment. The ROE automatic adjustment formulas tied to long-term Canada bond yields, used in recent years at the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power, have resulted in lower allowed ROEs. Regulatory decisions received in 2009 have reduced the risk of further decreases in allowed ROEs for certain of the Corporation's utilities and other utilities in Canada. In December 2009, the BCUC issued a decision increasing the allowed ROEs at TGI and FortisBC to 9.50 per cent and 9.90 per cent, respectively. The BCUC also determined that the previous ROE automatic adjustment formula will no longer apply and that the allowed ROE as determined in the BCUC decision will apply until reviewed further by the BCUC. In November 2009, the AUC issued its decision on the 2009 Generic Cost of Capital Proceeding. The decision increased the allowed ROE of utilities in Alberta that it regulates, including FortisAlberta, to 9.00 per cent and discontinued the use of the ROE automatic adjustment formula until reviewed further by the AUC. In December 2009, the OEB issued a report reviewing cost of capital for utilities in Ontario. The OEB increased the allowed ROE for utilities in Ontario that it regulates, including FortisOntario, to 9.75 per cent and refined the ROE automatic adjustment formula to reduce sensitivity to changes in long-term Canada bond yields and included an additional factor for utility bond spreads. The NEB, an independent federal agency that regulates several parts of Canada's energy industry, issued a decision in 2009 increasing the regulated total cost of capital of TQM, a Canadian regulated natural gas pipeline utility, which effectively established an approximate 100 basis point increase in TQM's allowed ROE for 2008 to 9.70 per cent on a 40 per cent equity ratio. The increase in the total cost of capital and allowed ROE was the result of a change in methodology, which now takes into account financial market information that considers, among other things, changes that have impacted financial markets and economic conditions. In October 2009, the NEB also issued a decision stating that its 1994 multi-pipeline rate of return on equity formula, used to determine the cost of capital for regulated pipeline companies, is no longer in effect, as there is doubt as to the ongoing correctness of using this formula. Instead, cost of capital will be determined by negotiations between the pipelines and their shippers or by the NEB.

The Corporation and its subsidiaries are also exposed to interest rate risk associated with borrowings under credit facilities and floating-rate long-term debt. However, the Terasen Gas companies and FortisBC have regulatory approval to defer any increase or decrease in interest expense resulting from fluctuations in interest rates associated with variable-rate credit facilities for recovery from, or refund to, customers in future rates. As described in the "Risk Factors - Derivative Financial Instruments and Hedging" section of this 2009 Annual Information Form, the Corporation and its subsidiaries may also enter into interest rate swap agreements from time to time to help reduce interest rate risk.

As at December 31, 2009, approximately 81 per cent of the Corporation's consolidated long-term debt and capital lease obligations had maturities beyond five years. With a significant portion of the Corporation's consolidated debt having long-term maturities, interest rate risk on debt refinancing has been reduced for the near and medium terms.

The following table outlines the nature of the Corporation's consolidated debt as at December 31, 2009.

Total Debt As at December 31, 2009		
	($ millions)	*(%)*
Short-term borrowings	415	7.0
Utilized variable-rate credit facilities classified as long-term	208	3.5
Variable-rate long-term debt and capital lease obligations (including current portion)	16	0.3
Fixed-rate long-term debt and capital lease obligations (including current portion)	5,276	89.2
Total	**5,915**	**100.0**

A change in the level of interest rates could materially affect the measurement and recording of changes in the fair value of interest rate swaps and the measurement and disclosure of the fair value of long-term debt. The impact of a material change in interest rates on the fair value measurement of the interest rate swap outstanding, as at December 31, 2009, is not expected to materially affect the Corporation's consolidated earnings and comprehensive income due to the low notional value of the interest rate swap and its near-term maturity.

Counterparty Risk: The Terasen Gas companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments. The Terasen Gas companies are also exposed to significant credit risk on physical off-system sales. The Terasen Gas companies deal with high credit-quality institutions in accordance with established credit approval practices. Due to events in the capital markets over the past year, including significant government intervention in the banking system, the Terasen Gas companies have further limited the financial counterparties they transact with and have reduced available credit to, or taken additional security from, the physical off-system sales counterparties with which they transact. The Terasen Gas companies did not experience any counterparty defaults in 2009 and are not expecting any counterparties to fail to meet their obligations. As events over the past year have indicated, however, the credit quality of counterparties can change rapidly.

FortisAlberta is exposed to credit risk associated with sales to retailers. Significantly all of FortisAlberta's distribution-service billings are to a relatively small group of retailers. As required under regulation, FortisAlberta minimizes its credit exposure associated with retailer billings by obtaining from the retailer a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating. See also the "Risk Factors - Economic Conditions" section of this 2009 Annual Information Form.

Competitiveness of Natural Gas: Prior to 2000, natural gas consistently enjoyed a substantial competitive advantage when compared with alternative sources of energy in British Columbia. However, since electricity prices in British Columbia continue to be set based on the historical average cost of production, rather than on market forces, they have remained artificially low compared to market-priced electricity. As a result, the price of electricity for residential customers in British Columbia is now only marginally higher than for natural gas. There is no assurance that natural gas will continue to maintain a competitive price advantage in the future. If natural gas pricing becomes uncompetitive with electricity pricing or pricing for alternative energy sources, the ability of the Terasen Gas companies to add new customers could be impaired and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. This may result in higher rates and could, in an extreme case, ultimately lead to an inability to fully recover the cost of service of the Terasen Gas companies in rates charged to customers. See also the "Risk Factors - Risks Related to TGVI" and "Risk Factors - Government of British Columbia's Energy Plan" sections of this 2009 Annual Information Form.

Natural Gas Supply: The Terasen Gas companies are dependent on a limited number of pipeline and storage providers, particularly in the Vancouver, Fraser Valley and Vancouver Island service areas where the majority of the natural gas distribution customers of the Terasen Gas companies are located. Regional market prices have been higher from time to time than prices elsewhere in North America, as a result of insufficient seasonal and peak storage and pipeline capacity to serve the increasing demand for natural gas in British Columbia and the U.S. Pacific Northwest. In addition, the Terasen Gas companies are critically dependent on a single-source transmission pipeline. In the event of a prolonged service disruption of the Spectra Pipeline System, residential customers of the Terasen Gas companies could experience outages, thereby affecting revenue and also resulting in costs to safely relight customers.

***Defined Benefit Pension Plan Performance and Funding Requirements**:* Each of Terasen, FortisAlberta, FortisBC, Newfoundland Power, FortisOntario, Algoma Power, Caribbean Utilities and Fortis maintain defined benefit pension plans for certain of their employees; however, only 60 per cent of the above utilities' total employees are members of such plans.

The Corporation's and subsidiaries' defined benefit pension plans are subject to judgments utilized in the actuarial determination of the accrued pension benefit obligation and related net pension cost. The primary assumptions utilized by management are the expected long-term rate of return on pension plan assets and the discount rate used to value the accrued pension benefit obligation.

Pension benefit obligations and related net pension cost can be affected by volatility in the global financial and capital markets. There is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future. With the exception of Newfoundland Power and Terasen, the pension plan assets are valued at fair value. At Newfoundland Power and Terasen, the pension plan assets are valued using the market-related value as disclosed in Note 2 to the 2009 consolidated financial statements. Market-driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the assumed long-term return on the assets. This may cause material changes in future pension funding requirements from current estimates and material changes in future net pension cost.

Market-driven changes impacting discount rates, which are used to value the accrued pension benefit obligations as at the measurement date of each of the defined benefit pension plans, may result in material changes in future pension funding requirements from current estimates and material changes in future net pension cost.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process as it affects the measurement of net pension cost, future funding requirements, the accrued benefit asset, accrued benefit liability and benefit obligation.

The above risks are mitigated as any increase or decrease in future pension funding requirements and/or net pension cost at the regulated utilities is expected to be recovered from, or refunded to, customers in future rates, subject to forecast risk. However, at the Terasen Gas companies and FortisBC, and at Newfoundland Power beginning in 2010, actual net pension cost above or below the forecast net pension cost approved for recovery in customer rates for the year is subject to deferral account treatment for recovery from, or refund to, customers in future rates, subject to regulatory approval. Also mitigating the above risks is the fact that the defined benefit pension plans at FortisAlberta and Newfoundland Power are closed to all new employees.

Risks Related to TGVI: TGVI is a franchise under development in the price-competitive service area of Vancouver Island, with a customer base and revenue that is insufficient to meet the Company's current cost of service. To assist with competitive rates during franchise development, the VINGPA provides royalty revenue from the Government of British Columbia that currently covers approximately 20 per cent of the cost of service. This revenue is due to expire at the end of 2011, after which time TGVI's customers will be required to absorb the full commodity cost of gas, all other costs of service and the recovery of any remaining accumulated revenue deficiencies. When VINGPA expires in 2011, the remaining amount outstanding under non-interest bearing senior government loans, which is currently treated as a reduction of rate base, will be required to be fully repaid. As at December 31, 2009, the balance outstanding under these loans was $53 million. As the debt is repaid, the cost of the higher rate base will increase the cost of service and customer rates, making gas less competitive with electricity on Vancouver Island.

Government of British Columbia's Energy Plan: The Government of British Columbia released its Energy Plan in February 2007. The Energy Plan is a natural progression from the previous plan, with consistent principles and a strong focus on environmental leadership, energy conservation and efficiency, and investing in innovation. The Energy Plan outlines various measures to address the challenges of global warming, including that all electricity produced in British Columbia will be required to have zero net greenhouse gas emissions by 2016. The Energy Plan places a significant responsibility on British Columbians to conserve energy by requiring 50 per cent of British Columbia's incremental resource needs to be achieved through conservation by 2020. The Energy Plan emphasizes efficiency by requiring BC Hydro to eliminate electricity imports and become fully self-sufficient by 2016. The Energy Plan also states that 90 per cent of British Columbia's electricity will come from renewable sources and that British Columbia will become the first jurisdiction in North America to require 100 per cent carbon sequestration for any coal-fired electricity project. Many of the principles of the Energy Plan were incorporated into the regulatory framework in British Columbia upon the British Columbia legislature's adoption of the *Utilities Commission Amendment Act*, *2008*. In addition, the *Carbon Tax Act*, *2008* provides for a consumption tax on carbon-based fuels, which affects the competitiveness of natural gas versus non-carbon-based energy sources. The Act, however, did not introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. The future impact of the Government of British Columbia's Energy Plan and the related legislation may have a material impact on the competitiveness of natural gas relative to other energy sources.

Environmental Risks: The Corporation and its subsidiaries are subject to numerous laws, regulations and guidelines governing the generation, management, storage, transportation, recycling and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment. Environmental damage and associated costs could potentially arise due to a variety of events, including the impact of severe weather and natural disasters on facilities and equipment, and equipment failure. Costs arising from environmental protection initiatives, compliance with environmental laws, regulations and guidelines or damages may become material to the Corporation and its subsidiaries. In addition, the process of obtaining environmental regulatory approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. During 2009, costs arising from environmental protection, compliance or damages were not material to the Corporation's consolidated results of operations, cash flows or financial position. The Corporation believes that it and its subsidiaries are materially compliant with environmental laws, regulations and guidelines applicable to them in the various jurisdictions in which they operate. As at December 31, 2009, there were no material environmental liabilities recorded in the Corporation's 2009 consolidated financial statements and there were no material unrecorded environmental liabilities known to management (see also, "Regulated Gas Utilities - Terasen Gas companies - Legal Proceedings" section of this 2009 Annual Information Form). The regulated utilities would seek to recover in customer rates the costs associated with environmental protection, compliance or damages; however, there is no assurance that the regulators would agree with the utilities' requests and, therefore, unrecovered costs, if substantial, could materially affect the results of operations, cash flows and financial position of the utilities.

From time to time, it is possible that the Corporation and its subsidiaries may become subject to government orders, investigations, inquiries or other proceedings relating to environmental matters. The occurrence of any of these events, or any changes in applicable environmental laws, regulations and guidelines or their enforcement or regulatory interpretation, could materially impact the results of operations, cash flows and financial position of the Corporation and its subsidiaries.

The Corporation's gas and electricity businesses are subject to inherent risks, including risk of fires and contamination of air, soil or water from hazardous substances. Risks associated with fire damage relate to the extent of forest and grassland cover, habitation and third-party facilities located on or near the land on which the utilities' facilities are situated. The utilities may become liable for fire suppression costs, regeneration and timber value costs and third-party claims in connection with fires on lands on which its facilities are located if it is found that such facilities were the cause of a fire and such claims, if successful, could be material. Risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to the storage and handling of large volumes of fuel, the use and/or disposal of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity. The risk of contamination of air, soil or water at the natural gas utilities primarily relates to natural gas and propane leaks and other accidents involving these substances. The management of greenhouse gas emissions is the main environmental concern of the Corporation's regulated gas utilities, primarily due to recent changes to the Government of British Columbia's Energy Plan and related legislation, as discussed above. Any changes in environmental laws, regulations or guidelines governing contamination could lead to significant increases in costs to the Corporation and its subsidiaries.

The key environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purpose of electricity generation.

Scientists and public health experts in Canada, the United States and other countries are studying the possibility that exposure to electric and magnetic fields from power lines, household appliances and other electricity sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health hazard, litigation could result and the electric utilities could be required to pay damages and take mitigation measures on its facilities. The costs of litigation, damages awarded and mitigation measures, if not approved by regulators for recovery in customer rates, could materially impact the results of operations, cash flows and financial condition of the electric utilities.

While the Corporation and its subsidiaries maintain insurance, there can be no assurance that all possible types of liabilities that may arise related to environmental matters will be covered by the insurance. For further information on insurance, refer to the "Risk Factors - Insurance Coverage Risk" section of this 2009 Annual Information Form.

As part of their respective environmental management systems, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor environmental performance.

For further information on environmental matters pertaining to the Corporation, refer to the "Environmental Matters" section of this 2009 Annual Information Form.

Insurance Coverage Risk: While the Corporation and its subsidiaries maintain insurance, a significant portion of the Corporation's regulated electric utilities' transmission and distribution assets are not covered under insurance, as is customary in North America, as the cost of the coverage is not considered economical. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its subsidiaries will be covered by insurance. The Corporation's regulated utilities would likely apply to their respective regulatory authority to recover the loss or liability through increased customer rates. However, there can be no assurance that a regulatory authority would approve any such application in whole or in part. Any major damage to the physical assets of the Corporation and its subsidiaries could result in repair costs and customer claims that are substantial in amount and which could have an adverse effect on the Corporation's and subsidiaries' results of operations, cash flow and financial position. In addition, the occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by the Corporation and its subsidiaries or claims that fall within a significant self-insured retention could have a material adverse effect on the Corporation's and subsidiaries' results of operations, cash flow and financial position.

It is anticipated that such insurance coverage will be maintained. However, there can be no assurance that the Corporation and its subsidiaries will be able to obtain or maintain adequate insurance in the future at rates considered reasonable or that insurance will continue to be available on terms as favourable as the existing arrangements or that the insurance companies will meet their obligations to pay claims.

Licences and Permits: The acquisition, ownership and operation of gas and electric utilities and assets require numerous licences, permits, approvals and certificates from various levels of government and government agencies. The Corporation's regulated utilities and non-regulated generation operations 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 there is a failure to obtain or maintain any required approval or to comply with any applicable law, regulation or condition of an approval, the operation of the assets and the sale of gas and electricity could be prevented or become subject to additional costs, any of which could materially affect the subsidiaries.

FortisBC'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 as of July 1, 2005 depends upon the maintenance of its water licences issued under the *Water Act* (British Columbia). In addition, water flows on 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.

Loss of Service Area: FortisAlberta serves customers residing within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta located within their municipal boundaries. Upon the termination of its franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta). Under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric utility expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides for compensation, including payment for FortisAlberta's assets on the basis of replacement cost less depreciation. Given the historical growth of Alberta and its municipalities, FortisAlberta may be affected by transactions of this type.

The consequence to FortisAlberta of a municipality purchasing its distribution assets would be an erosion of the Company's rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. No transactions are currently in progress with FortisAlberta pursuant to the *Municipal Government Act* (Alberta). However, upon expiration of franchise agreements, there is a risk that municipalities will opt to purchase the distribution assets existing within their boundaries, the loss of which could materially affect the results of operations, cash flow and financial position of FortisAlberta.

Market Energy Sales Prices: The Corporation's primary exposure to changes in market energy sales prices had related to its non-regulated energy sales in Ontario, where energy was sold to the IESO at market prices. Non-regulated energy sales in Ontario largely related to a power-for-water exchange agreement, known as the Niagara Exchange Agreement, associated with the Rankine hydroelectric generating facility. FortisOntario's water entitlement on the Niagara River expired April 30, 2009 at the end of a 100-year term and, as a result, the Corporation's exposure to market price fluctuations in Ontario has been substantially reduced as earnings related to the Rankine facility have ceased after that date. During 2009, earnings' contribution associated with the Rankine facility was $3.5 million. To a lesser degree, the Corporation is also exposed to changes in energy prices related to energy sales from its non-regulated generation assets in Upper New York State. All energy produced by these assets is sold to the National Grid at market prices. Energy from the Corporation's non-regulated generation assets in Belize, central Newfoundland and British Columbia is sold under medium- and long-term fixed-price contracts.

Transition to IFRS: Effective January 1, 2011, Canadian publicly accountable enterprises are required to adopt IFRS as issued by the IASB. IFRS will require increased financial statement disclosure and will result in differences in accounting policies between Canadian GAAP and IFRS. The Corporation continues to assess the impact on its future financial reporting of transitioning to IFRS. In July 2009, the IASB issued the Exposure Draft - *Rate-Regulated Activities* stating that regulatory assets and liabilities arising from activities subject to cost of service regulation would be recognized under IFRS when certain conditions are met. The ability to record regulatory assets and liabilities, as proposed, should reduce earnings' volatility at the Corporation's regulated utilities that may otherwise result under IFRS in the absence of an accounting standard for rate-regulated activities. Conversely, if an accounting standard for rate-regulated activities is not approved or if a standard is approved that is substantially different from that proposed, this could increase volatility in the earnings of the Corporation's regulated utilities.

Changes in Tax Legislation: The Government of Canada has enacted legislative changes that will challenge the continuation of the tax-deferred status of offshore earnings derived from foreign affiliates. The legislative changes will require that the governments of these tax-free jurisdictions enter into tax treaties or other comprehensive TIEAs with Canada before 2015. If the jurisdictions are unable to establish these tax treaties or TIEAs, the earnings of Canadian subsidiaries operating in these jurisdictions will be taxed on an accrual basis after 2014 as if they were earned in Canada. Conversely, if tax treaties or TIEAs can be reached, the earnings from these jurisdictions will be able to be repatriated to Canada tax-free. In the event that the offshore earnings become taxable, earnings' contribution from Regulated Electric Utilities - Caribbean and BECOL will decrease.

On December 10, 2008, the Advisory Panel on Canada's System of International Taxation provided its recommendations to the Minister of Finance of the Government of Canada in its final report, *Enhancing Canada's International Tax Advantage*. The Advisory Panel was formed by the Government of Canada in November 2007 to provide recommendations to improve Canada's international tax policy respecting foreign investment by Canadian businesses and investment in Canada by foreign businesses. The Advisory Panel's recommendations seek to improve Canada's tax system regarding outbound and inbound business investment, non-resident withholding taxes and administration, compliance and legislative processes. Specifically, the Advisory Panel recommended that the Government of Canada pursue TIEAs on a government-to-government basis without resorting to accrual taxation for foreign active business income if TIEAs are not obtained. The Advisory Panel also recommended that the Government of Canada broaden the existing exemption system to cover all foreign active business income earned by foreign affiliates.

Many of the proposals related to foreign affiliate measures, first announced in February 2004, are still in draft form. In the 2009 federal budget documents, the Government of Canada stated that the remaining proposals will be re-evaluated in light of the recommendations of the Advisory Panel before a decision is made on whether and how to proceed with them. On December 18, 2009, the Department of Finance of the Government of Canada released draft legislation, regulations and explanatory notes concerning the foreign affiliate rules under the federal *Income Tax Act*. These measures implement many of the foreign affiliate proposals announced on February 27, 2004.

As of August 31, 2009, the Department of Finance of the Government of Canada reported that it had entered into TIEA negotiations with the Cayman Islands and the Turks and Caicos Islands in June 2009. If agreements can be negotiated, the earnings from Caribbean Utilities and Fortis Turks and Caicos could be repatriated to Canada tax-free.

The Corporation is not aware if the Government of Canada has initiated similar negotiations with the Government of Belize. Any future changes in other tax legislation could also materially affect the Corporation's consolidated earnings.

Information Technology Infrastructure: The ability of the Corporation's utilities to operate effectively is dependent upon developing, managing and maintaining complex information systems and infrastructure that are employed to support the operation of distribution, transmission and generation facilities, provide customers with billing and load settlement information and support the financial and general operating aspects of their business. System failures could have a material adverse effect on the utilities.

First Nations' Lands: The Terasen Gas companies and FortisBC provide service to customers on First Nations' reserves and maintain gas and electric distribution facilities, and electric transmission and generation facilities, on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations' bands and the Government of British Columbia is underway, but the basis upon which settlements might be reached in the service areas of the Terasen Gas companies and FortisBC 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 Terasen Gas companies and FortisBC. However, there can be no certainty that the settlement process will not materially affect the business of the Terasen Gas companies and FortisBC. In addition, FortisAlberta has distribution assets on First Nations' lands with access permits to these lands held by TransAlta. In order for FortisAlberta to acquire these access permits, both the Department of Indian and Northern Affairs Canada and the individual band councils must grant approval. FortisAlberta may not be able to acquire the access permits from TransAlta and may be unable to negotiate land-use agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to FortisAlberta and, therefore, may have a material effect on the business of FortisAlberta.

Labour Relations: Approximately 58 per cent of the employees of the Corporation's subsidiaries are members of labour unions or associations that have entered into collective bargaining agreements with the subsidiaries. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the businesses carried out by the subsidiaries. The Corporation considers the relationships of its subsidiaries with its labour unions and associations 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 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 rate orders at the regulated utilities and which could have a material effect on the results of operations, cash flow and financial position of the utilities.

Human Resources: The ability of Fortis to deliver service in a cost-effective manner is dependent on the ability of the Corporation's subsidiaries to attract, develop and retain skilled workforces. Like other utilities across Canada and the Caribbean, the Corporation's utilities are faced with demographic challenges relating to trades, technical staff and engineers. The growing size of the Corporation and an increasingly competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program over the next several years will present challenges in ensuring the Corporation's utilities have the qualified workforce necessary to complete the capital work initiatives.

7.0 GENERAL DESCRIPTION OF SHARE CAPITAL STRUCTURE

The authorized share capital of the Corporation consists of the following:

(a) an unlimited number of Common Shares without nominal or par value;
(b) an unlimited number of First Preference Shares without nominal or par value; and
(c) an unlimited number of Second Preference Shares without nominal or par value.

At March 5, 2010, the following Common Shares and First Preference Shares were issued and outstanding.

Share Capital	Issued and Outstanding	Votes per Share
Common Shares	172,050,701	One
First Preference Shares, Series C	5,000,000	None
First Preference Shares, Series E	7,993,500	None
First Preference Shares, Series F	5,000,000	None
First Preference Shares, Series G	9,200,000	None
First Preference Shares, Series H	10,000,000	None

The following table summarizes the cash dividends declared per share for each of the Corporation's class of share for the past three years.

	Dividends Declared *(per share)*		
Share Capital	**2007**	**2008**	**2009**
Common Shares	$0.88	$1.01	$0.78
First Preference Shares, Series C	$1.3625	$1.3625	$1.3625
First Preference Shares, Series E	$1.2250	$1.2250	$1.2250
First Preference Shares, Series F	$1.2250	$1.2250	$1.2250
First Preference Shares, Series G (1)	-	$1.0184	$1.3125
First Preference Shares, Series H (2)	-	-	-

(1) *The First Preference Shares, Series G were issued in May and June 2008.*
(2) *The First Preference Shares, Series H were issued in January 2010, and are initially entitled to receive cumulative dividends in the amount of $1.0625 per annum.*

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on Common and Preferred Shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

On January 11, 2010, the Board declared an increase in the quarterly Common Share dividend to $0.28 per share from $0.26 per share, with the first payment occurring on March 1, 2010, to holders of record as of February 5, 2010. Also on January 11, 2010, the Board declared a first quarter 2010 dividend on the First Preference Shares, Series C, E, F and G in accordance with the applicable annual prescribed rate and was paid on March 1, 2010 to holders of record as of February 5, 2010.

On March 2, 2010, the Board declared a second quarter 2010 dividend of $0.28 per Common Share and a second quarter 2010 dividend on the First Preference Shares, Series C, E, F, G and H in accordance with the applicable annual prescribed rate. The first dividend associated with the First Preference Shares, Series H will be in the amount of $0.3668 per share to be paid on June 1, 2010. In each case, the second quarter 2010 dividends will be paid on June 1, 2010 to holders of record as of May 7, 2010.

Common Shares

Dividends on Common Shares are declared at the discretion of the Board. Holders of Common Shares are entitled to dividends on a pro rata basis if, as, and when declared by the Board. Subject to the rights of the holders of the First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive dividends in priority to or rateably with the holders of the Common Shares, the Board may declare dividends on the Common Shares to the exclusion of any other class of shares of the Corporation.

On the liquidation, dissolution or winding-up of Fortis, holders of Common Shares are entitled to participate rateably in any distribution of assets of Fortis, subject to the rights of holders of First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or rateably with the holders of the Common Shares.

Holders of the Common Shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Fortis, other than separate meetings of holders of any other class or series of shares, and are entitled to one vote in respect of each Common Share held at such meetings.

First Preference Shares, Series C

The 5,000,000 First Preference Shares, Series C are entitled to fixed cumulative preferential cash dividends at a rate of $1.3625 per share per annum. On or after June 1, 2010, the Corporation may, at its option, redeem for cash the First Preference Shares, Series C, in whole at any time, or in part from time to time, at $25.75 per share if redeemed before June 1, 2011; at $25.50 per share if redeemed on or after June 1, 2011 but before June 1, 2012; at $25.25 per share if redeemed on or after June 1, 2012 but before June 1, 2013; and at $25.00 per share if redeemed on or after June 1, 2013 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. On or after June 1, 2010, the Corporation may, at its option, convert all, or from time to time, any part of the outstanding First Preference Shares, Series C into fully paid and freely tradable Common Shares of the Corporation. The number of Common Shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per Preference Share, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95 per cent of the then-current market price of the Common Shares. On or after September 1, 2013, each First Preference Share, Series C will be convertible at the option of the holder on the first day of September, December, March and June of each year into freely tradable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95 per cent of the then-current market price of the Common Shares. If a holder of First Preference Shares, Series C elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference Shares, Series C for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series E

The 7,993,500 First Preference Shares, Series E are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. On or after June 1, 2013, the Corporation may, at its option, redeem all, or from time to time any part of, the outstanding First Preference Shares, Series E by the payment in cash of a sum per redeemed share equal to $25.75 if redeemed during the 12 months commencing June 1, 2013; $25.50 if redeemed during the 12 months commencing June 1, 2014; $25.25 if redeemed during the 12 months commencing June 1, 2015; and $25.00 if redeemed on or after June 1, 2016 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. On or after June 1, 2013, the Corporation may, at its option, convert all, or from time to time any part of the outstanding First Preference Shares, Series E into fully paid and freely tradable Common Shares of the Corporation.

The number of Common Shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per First Preference Share, Series E, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95 per cent of the then-current market price of the Common Shares at such time. On or after September 1, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first business day of September, December, March and June of each year, into fully paid and freely tradable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95 per cent of the then-current market price of the Common Shares. If a holder of First Preference Shares, Series E elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference, Shares E for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series F

The 5,000,000 First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. On or after December 1, 2011, the Corporation may, at its option, redeem for cash the First Preference Shares, Series F, in whole at any time or in part from time to time, at $26.00 per share if redeemed before December 1, 2012; at $25.75 per share if redeemed on or after December 1, 2012 but before December 1, 2013; at $25.50 per share if redeemed on or after December 1, 2013 but before December 1, 2014; at $25.25 per share if redeemed on or after December 1, 2014 but before December 1, 2015; and at $25.00 per share if redeemed on or after December 1, 2015 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series G

The 9,200,000 First Preference Shares, Series G are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.3125 per share per annum for each year up to and including August 31, 2013. For each five-year period after that date, the holders of First Preference Shares, Series G are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying the $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13 per cent. On September 1, 2013, and on September 1 every five years thereafter, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series G, in whole at any time, or in part from time to time, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series H

The 10,000,000 First Preference Shares, Series H are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.0625 per share per annum for each year up to but excluding June 1, 2015. For each five-year period after that date, the holders of First Preference Shares, Series H are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 1.45 per cent.

On each Series H Conversion Date, being June 1, 2015, and June 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series H, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series H Conversion Date, the holders of First Preference Shares, Series H, have the option to convert any or all of their First Preference Shares, Series H into an equal number of cumulative redeemable floating rate First Preference Shares, Series I.

The holders of First Preference Shares, Series I will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada Treasury Bills plus 1.45 per cent.

On each Series I Conversion Date, being June 1, 2020, and June 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On any date after June 1, 2015, that is not a Series I Conversion Date, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series I Conversion Date, the holders of First Preference Shares, Series I, have the option to convert any or all of their First Preference Shares, Series I into an equal number of First Preference Shares, Series H.

On any Series H Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series H outstanding, such remaining First Preference Shares, Series H will automatically be converted into an equal number of First Preference Shares, Series I. On any Series I Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series I outstanding, such remaining First Preference Shares, Series I will automatically be converted into an equal number of First Preference Shares, Series H. However, if such automatic conversions would result in less than 1,000,000 Series I First Preference Shares or less than 1,000,000 Series H First Preference Shares outstanding then no automatic conversion would take place.

Convertible Debentures

The Corporation's US$40 million 5.50% Unsecured Subordinated Convertible Debentures, due 2016, are redeemable by the Corporation at par at any time on or after November 7, 2011 and are convertible, at the option of the holder, into the Corporation's Common Shares at US$29.11 per share. The debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the debentures. There is no provision associated with these debentures that restricts the payment of dividends.

Debt Covenant Restrictions on Dividend Distributions

The Trust Indenture pertaining to the Corporation's $100 million Senior Unsecured Debentures contains a covenant which provides that Fortis shall not declare or pay any dividends (other than stock dividends or cumulative preferred dividends on preferred shares not issued as stock dividends) or make any other distribution on its shares if, immediately thereafter, its consolidated funded obligations would be in excess of 75 per cent of its total consolidated capitalization.

The Trust Indenture pertaining to the Corporation's $200 million Senior Unsecured Debentures contains a covenant which provides that Fortis shall not declare or pay any dividends (other than stock dividends or cumulative preferred dividends on preferred shares not issued as stock dividends) or make any other distribution on its shares or redeem any of its shares or prepay Subordinated Debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75 per cent of its total consolidated capitalization.

The Corporation has a $600 million unsecured committed revolving credit facility, maturing in May 2012, that can be used for general corporate purposes, including acquisitions. The credit facility contains a covenant which provides that Fortis shall not declare or pay any dividends or make any other restricted payments if, immediately thereafter, consolidated debt to consolidated capitalization ratio would exceed 70 per cent at any time.

As at December 31, 2009 and 2008, the Corporation was in compliance with its debt covenant restrictions pertaining to dividend distributions, as described above.

8.0 CREDIT RATINGS

Securities issued by Fortis and its currently rated utilities are rated by one or more credit rating agencies, namely, DBRS, S&P and/or Moody's. The ratings assigned to securities issued by Fortis and its currently rated utilities are reviewed by the agencies on an ongoing basis. Credit ratings and stability ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are not recommendations to buy, sell or hold securities. Ratings may be subject to revision or withdrawal at any time by the rating organization. The following table summarizes the Corporation's credit ratings as at March 8, 2010.

Fortis Credit Ratings

Company	DBRS	S&P	Moody's
Fortis	BBB (high), stable (unsecured debt)	A-, stable (unsecured debt)	N/A
Terasen	BBB (high), stable (unsecured debt)	BBB+, stable (1) (unsecured debt)	Baa2, stable (unsecured debt)
TGI	A, stable (secured & unsecured debt)	A, stable (1) (unsecured debt)	A3, stable (unsecured debt)
TGVI	N/A	N/A	A3, stable (unsecured debt)
FortisAlberta	A (low), stable (senior unsecured debt)	A-, stable (senior unsecured debt)	Baa1, stable (senior unsecured debt)
FortisBC	BBB (high), stable (secured & unsecured debt)	N/A	Baa2, stable (unsecured debt)
Newfoundland Power	A, stable (first mortgage bonds)	N/A	A2, stable (first mortgage bonds)
Maritime Electric	N/A	A, stable (senior secured debt)	N/A
Caribbean Utilities	A (low), stable (senior unsecured debt)	A, negative (senior unsecured debt)	N/A

(1) Unsolicited

DBRS rates debt instruments by rating categories ranging from AAA to D, which represents the range from highest to lowest quality of such securities. DBRS states that: (i) 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; (ii) its 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; and (iii) every rating is based on quantitative and qualitative considerations that are relevant for the borrowing entity. According to DBRS, a rating of A by DBRS is in the middle of three subcategories within the third highest of nine major categories. Such rating is assigned to debt instruments considered to be of satisfactory credit quality and for which protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. Entities in the BBB category are considered to have long-term debt 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. The assignment of a (high) or (low) modifier within each rating category indicates relative standing within such category.

S&P long-term debt ratings are on a ratings scale that ranges from AAA to C, which represents the range from highest to lowest quality of such securities. S&P uses '+' or '-' designations to indicate the relative standing of securities within a particular rating category. S&P states that its credit ratings are

current opinions of the financial security characteristics with respect to the ability to pay under contracts in accordance with their terms. This opinion is not specific to any particular contract, nor does it address the suitability of a particular contract for a specific purpose or purchaser. An issuer rated A is regarded as having financial security characteristics to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than those in higher-rated categories.

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 states that its long-term debt ratings are opinions of relative risk of fixed-income obligations with an original maturity of one year or more and that 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 and such a debt rating is assigned to debt instruments considered to be of medium-grade quality. Debt instruments rated Baa are subject to moderate credit risk and may possess certain speculative characteristics. Debt instruments rated A are considered upper-medium grade and are subject to low credit risk.

9.0 MARKET FOR SECURITIES

The Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; and First Preference Shares, Series H of Fortis are listed on the Toronto Stock Exchange under the symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F, FTS.PR.G and FTS.PR.H, respectively. The First Preference Shares, Series H were issued in January 2010.

The following table sets forth the reported high and low trading prices and trading volumes for the Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; and First Preference Shares, Series G on a monthly basis for the year ended December 31, 2009.

Fortis
2009 Trading Prices and Volumes

	Common Shares			First Preference Shares, Series C		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
Jan	25.06	22.89	7,809,701	26.65	25.16	97,287
Feb	24.60	22.33	14,130,845	26.55	25.15	50,592
Mar	24.24	21.52	14,643,369	25.99	24.50	81,017
Apr	23.20	21.55	11,180,355	26.65	25.26	79,564
May	24.31	22.15	11,200,604	26.95	25.52	38,926
Jun	26.25	23.67	10,446,255	27.49	25.58	42,894
Jul	26.19	24.00	9,178,843	27.18	25.70	211,455
Aug	25.99	24.61	8,110,618	27.75	26.60	44,986
Sep	25.39	24.62	8,323,744	27.00	26.20	301,981
Oct	26.24	24.61	8,776,294	26.60	26.35	71,673
Nov	27.13	25.10	8,018,968	26.60	36.20	34,639
Dec	29.24	26.19	9,343,236	26.50	26.30	35,380

	First Preference Shares, Series E			First Preference Shares, Series F		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
Jan	27.99	24.25	161,245	19.84	17.00	126,556
Feb	25.30	25.00	60,300	20.54	18.26	91,487
Mar	25.00	24.80	64,032	20.40	18.80	65,467
Apr	25.25	24.90	135,449	20.03	19.01	65,507
May	25.45	24.90	92,569	20.89	19.05	99,625
Jun	26.48	25.50	63,207	20.50	19.50	79,762
Jul	26.39	25.80	273,473	22.07	19.78	71,397
Aug	27.00	25.80	78,233	22.95	20.75	101,294
Sep	27.77	26.16	38,648	22.76	20.89	52,237
Oct	26.89	25.55	22,395	21.95	21.19	90,588
Nov	26.75	25.95	316,465	22.25	21.50	74,136
Dec	27.00	26.25	140,681	21.70	21.15	57,368

	First Preference Shares, Series G		
Month	**High ($)**	**Low ($)**	**Volume**
Jan	23.00	19.90	128,062
Feb	23.98	22.29	83,648
Mar	23.70	21.50	88,211
Apr	25.00	22.44	117,185
May	25.49	23.94	152,290
Jun	25.75	24.70	121,421
Jul	26.36	25.25	164,608
Aug	26.67	25.10	208,514
Sep	26.24	25.21	180,506
Oct	26.01	25.35	145,816
Nov	26.49	25.75	51,453
Dec	27.17	26.10	63,422

10.0 DIRECTORS AND OFFICERS

The Board adopted a director tenure policy in 1999 which is reviewed on a periodic basis and was most recently affirmed at a meeting of the Board held in September 2007. The tenure policy provides that Directors of the Corporation are to be elected for a term of one year and, except in exceptional circumstances determined by the Board, be eligible for re-election until the Annual Meeting of Shareholders next following the earlier of the date on which they achieve age 70 or the 10th anniversary of their initial election to the Board. The policy does not apply to Mr. Marshall whose service on the Board is related to his tenure as CEO. The following chart sets out the name and municipality of residence of each of the Directors of Fortis and indicates their principal occupations within five preceding years.

Fortis Directors	
Name	**Principal Occupations Within Five Preceding Years**
PETER E. CASE (1) Freelton, Ontario	Mr. Case, 55, a Corporate Director, retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. During his 17-year career as senior investment analyst with CIBC World Markets and BMO Nesbitt Burns and its predecessors, Mr. Case's coverage of Canadian and selected U.S. pipeline and energy utilities was consistently rated among the top rankings. He was awarded a Bachelor of Arts and a Master of Business Administration from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto. Mr. Case was first elected to the Board in May 2005. He was appointed Chair of the Board of FortisOntario in 2009. Mr. Case has been a Director of FortisOntario since March 2003 He does not serve as a director of any other reporting issuer.
FRANK J. CROTHERS Nassau, Bahamas	Mr. Crothers, 65, is Chairman and Chief Executive Officer of Island Corporate Holdings Limited, Nassau, Bahamas. Over the past 35 years, he has served on many public and private sector boards. For more than a decade he was on the Board of Harvard University Graduate School of Education and also served a three-year term as Chairman of CARILEC, the Caribbean Association of Electrical Utilities. Mr. Crothers is the past President of P.P.C. Limited, which was acquired by the Corporation in August 2006. He serves as the Vice Chair of the Board of Caribbean Utilities and serves on the Board of Belize Electricity. Mr. Crothers was first elected to the Fortis Board in May 2007. He is also a director of reporting issuers Templeton Mutual Funds, Fidelity Merchant Bank & Trust (Cayman) Limited and Talon Metals Corp.
IDA J. GOODREAU (3) Vancouver, British Columbia	Ms. Goodreau, 58, is the past President and Chief Executive Officer of LifeLabs. Prior to joining Lifelabs in March 2009, she was President and Chief Executive Officer of Vancouver Coastal Health Authority since 2002. Ms. Goodreau has held senior leadership roles in several Canadian and international pulp and paper and natural gas companies prior to entering the health care field. She was awarded a Master of Business Administration and a Bachelor of Commerce, Honors, degree from the University of Windsor and a Bachelor of Arts, (English and Economics) from the University of Western Ontario. Ms. Goodreau was first elected to the Board in May 2009. She has served on numerous private and public sector boards and is a director of Terasen.
DOUGLAS J. HAUGHEY (1) Calgary, Alberta	Mr. Haughey, 53, is President and Chief Executive Officer of WindShift Capital Corp. focused on energy infrastructure investment opportunities in North America. Prior to forming Windshift Capital Corp. in 2008, he held several executive roles with Spectra Energy and predecessor companies. He had overall responsibility for its western Canadian natural gas midstream business, was President and Chief Executive Officer of Spectra Energy Income Fund and also led Spectra's strategic development and mergers and acquisitions teams based in Houston, Texas. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with a Master of Business Administration. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors. He was first elected to the Board in May 2009. Mr. Haughey also serves as a director of Pembina Pipeline Income Fund.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
GEOFFREY F. HYLAND (1)(2)(3) Caledon, Ontario	Mr. Hyland, 65, a Corporate Director, retired as President and Chief Executive Officer of ShawCor Ltd. in June 2005 after 37 years of service. He graduated from McGill University with a Bachelor of Engineering (Chemical) and York University with a Master of Business Administration. Mr. Hyland was first elected to the Board in May 2001 and was appointed Chair of the Board in May 2008. He is a director of FortisOntario. Mr. Hyland continues to serve on the board of ShawCor Ltd. and is a director of SCITI Total Return Trust and Exco Technologies Limited.
H. STANLEY MARSHALL Paradise, Newfoundland and Labrador	Mr. Marshall, 59, is President and Chief Executive Officer of the Corporation. He joined Newfoundland Power in 1979 and was appointed President and Chief Executive Officer of Fortis in 1996. Mr. Marshall graduated from the University of Waterloo with a Bachelor of Applied Science (Chem. Eng.) and Dalhousie University with a Bachelor of Laws. He is a member of the Law Society of Newfoundland and Labrador and a Registered Professional Engineer in the Province of Newfoundland and Labrador. Mr. Marshall was first elected to the Board in October 1995. He serves on the boards of all Fortis utilities in western Canada and the Caribbean (including Caribbean Utilities) and the Board of Fortis Properties. He is also a director of Toromont Industries Ltd.
JOHN S. McCALLUM (1)(2) Winnipeg, Manitoba	Mr. McCallum, 66, has been a Professor of Finance at the University of Manitoba since July 1973. He served as Chairman of Manitoba Hydro from 1991 to 2000 and as Policy Advisor to the Federal Minister of Finance from 1984 to 1991. Mr. McCallum graduated from the University of Montreal with a Bachelor of Arts (Economics) and a Bachelor of Science (Mathematics). He was awarded a Master of Business Administration from Queen's University and a PhD in Finance from the University of Toronto. Mr. McCallum was first elected to the Board in July 2001 and was appointed Chair of the Governance and Nominating Committee of the Corporation in May 2005. He is a director of FortisBC and FortisAlberta and chairs the Audit, Risk and Environment Committees of both companies. Mr. McCallum also serves as a director of IGM Financial Inc., Toromont Industries Ltd. and Wawanesa.
HARRY McWATTERS (2) Summerland, British Columbia	Mr. McWatters, 64, is the founder and past President of Sumac Ridge Estate Wine Group, a leader in the British Columbia wine industry. He is President of Vintage Consulting Group Inc., Harry McWatters Inc., Okanagan Wine Academy and Black Sage Vineyards Ltd., all of which are engaged in various aspects of the British Columbia wine industry. Mr. McWatters was first elected to the Board in May 2007. He was elected to the Board of FortisBC Inc. in September 2005 and appointed as Chair of that Company's Board in 2006. Mr. McWatters became a director of Terasen in November 2007 and does not serve as a director of any other reporting issuer.
RONALD D. MUNKLEY (2) Mississauga, Ontario	Mr. Munkley, 63, a Corporate Director, retired in April 2009 as Vice Chairman and Head of the Power and Utility Business of CIBC World Markets. Mr. Munkley had acted as an advisor on most Canadian utility transactions since joining CIBC World Markets in 1998. Prior to that, he was employed at Enbridge Consumers Gas for 27 years, culminating as Chairman, President and Chief Executive Officer. Mr. Munkley led Enbridge Consumers Gas through deregulation and restructuring in the 1990s. He graduated from Queen's University with a Bachelor of Science, Honors (Engineering). Mr. Munkley is a professional engineer and has completed the Executive and Senior Executive Programs of the University of Western Ontario and the Partners, Directors and Senior Officers Certificate of the Canadian Securities Institute. He was first elected to the Board in May 2009.
DAVID G. NORRIS (1)(3) St. John's, Newfoundland and Labrador	Mr. Norris, 62, a Corporate Director, has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited. Previously, he held Deputy Minister positions with the Department of Finance and Treasury Board, Government of Newfoundland and Labrador. Mr. Norris graduated with a Bachelor of Commerce from Memorial University of Newfoundland and a Master of Business Administration from McMaster University. He was first elected to the Board in May 2005 and, in May 2006, Mr. Norris was appointed Chair of the Audit Committee of the Board. He has been a director of Newfoundland Power since 2003 and was appointed Chair of that Company's Board in April 2006. Mr. Norris was appointed to the Board of Fortis Properties in 2006. He does not serve as a director of any other reporting issuer.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
MICHAEL A. PAVEY (3) Moncton, New Brunswick	Mr. Pavey, 62, a Corporate Director, retired as Executive Vice-President and Chief Financial Officer of Major Drilling Group International Inc. in September 2006. Prior to joining Major Drilling Group International Inc. in 1999, he held senior executive positions with a major integrated electric utility in western Canada. Mr. Pavey graduated from the University of Waterloo with a Bachelor of Applied Science (Mechanical Engineering) and from McGill University with a Master of Business Administration. He retired from the Board of Maritime Electric in February 2007 after a six-year term, which included three years' service as Chair of that Company's Audit and Environment Committee. Mr. Pavey was first elected to the Board in May 2004. Mr. Pavey does not serve as a director of any other reporting issuer.
ROY P. RIDEOUT (2)(3) Halifax, Nova Scotia	Mr. Rideout, 62, a Corporate Director, retired as Chairman and Chief Executive Officer of Clarke Inc. in October 2002. Prior to 1998, he served as President of Newfoundland Capital Corporation Limited and held senior executive positions in the Canadian airline industry. Mr. Rideout graduated with a Bachelor of Commerce from Memorial University of Newfoundland and obtained designation as a Chartered Accountant. Mr. Rideout was first elected to the Board in March 2001. He is the Chair of the Human Resources Committee of the Board and has held that position since May 2003. Mr. Rideout also serves as a director of NAV CANADA.

(1) *Serves on the Audit Committee*
(2) *Serves on the Governance and Nominating Committee*
(3) *Serves on the Human Resources Committee*

The following table sets out the name and municipality of residence of each of the officers of Fortis and indicates the office held.

Fortis Officers	
Name and Municipality of Residence	**Office Held**
H. Stanley Marshall Paradise, Newfoundland and Labrador	President and Chief Executive Officer (1)
Barry V. Perry Mount Pearl, Newfoundland and Labrador	Vice President, Finance and Chief Financial Officer (2)
Ronald W. McCabe St. John's, Newfoundland and Labrador	Vice President, General Counsel and Corporate Secretary (3)
Donna G. Hynes St. John's, Newfoundland and Labrador	Assistant Secretary (4)

(1) *Mr. Marshall was appointed President and Chief Operating Officer, effective October 1, 1995. Effective May 1, 1996, Mr. Marshall became Chief Executive Officer.*
(2) *Mr. Perry was appointed Vice President, Finance and Chief Financial Officer, effective January 1, 2004. Prior to that time, Mr. Perry was Vice President, Finance and Chief Financial Officer of Newfoundland Power.*
(3) *Mr. McCabe was appointed General Counsel and Corporate Secretary, effective January 1, 1997. Effective May 6, 2008, Mr. McCabe became Vice President, General Counsel and Corporate Secretary.*
(4) *Ms. Hynes was appointed Assistant Secretary, effective December 8, 1999. She joined Fortis as Manager, Investor and Public Relations in October 1999 and, prior to that time, was employed by Newfoundland Power.*

As at December 31, 2009, the directors and officers of Fortis, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 684,201 Common Shares, representing 0.4 per cent of the issued and outstanding Common Shares of Fortis. The Common Shares are the only voting securities of the Corporation.

11.0 AUDIT COMMITTEE

11.1 Education and Experience

The education and experience of each Audit Committee Member that is relevant to such Member's responsibilities as a Member of the Audit Committee are set out below. As at December 31, 2009, the Audit Committee was composed of the following persons.

Fortis Audit Committee	
Name	**Relevant Education and Experience**
PETER E. CASE Freelton, Ontario	Mr. Case retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. He was awarded a Bachelor of Arts and a Master of Business Administration from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto.
DOUGLAS J. HAUGHEY Calgary, Alberta	Mr. Haughey is President and Chief Executive Officer of WindShift Capital Corp. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with a Master of Business Administration. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors.
GEOFFREY F. HYLAND Caledon, Ontario	Mr. Hyland retired as President and Chief Executive Officer of ShawCor Ltd. in June 2005 after 37 years of service. He graduated from McGill University with a Bachelor of Engineering (Chemical) and from York University with a Master of Business Administration.
JOHN S. McCALLUM Winnipeg, Manitoba	Mr. McCallum is a Professor of Finance at the University of Manitoba. He graduated from the University of Montreal with a Bachelor of Arts (Economics) and a Bachelor of Science (Mathematics). Mr. McCallum was awarded a Master of Business Administration from Queen's University and a PhD in Finance from the University of Toronto.
DAVID G. NORRIS *(Chair)* St. John's, Newfoundland and Labrador	Mr. Norris graduated with a Bachelor of Commerce from Memorial University of Newfoundland and a Master of Business Administration from McMaster University. He has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited.

The Board has determined that each of the Audit Committee Members is independent and financially literate. Independent means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110 - Audit Committees. Financially literate means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

11.2 Audit Committee Mandate

The text of the Corporation's Audit Committee Mandate is detailed below.

Objective

The Audit Committee shall provide assistance to the Board by overseeing the external audit of the Corporation's annual financial statements and the accounting and financial reporting and disclosure processes and policies of the Corporation.

Definitions

In this mandate:

"AIF" means the Annual Information Form filed by the Corporation;

"Committee" means the Audit Committee appointed by the Board pursuant to this mandate;

"Board" means the board of directors of the Corporation;

"CICA" means the Canadian Institute of Chartered Accountants or any successor body;

"Corporation" means Fortis Inc.;

"**Director"** means a member of the Board;

"Financially Literate" means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be present in the Corporation's financial statements;

"External Auditor" means the firm of chartered accountants, registered with the Canadian Public Accountability Board or its successor, and appointed by the shareholders of the Corporation to act as External Auditor of the Corporation;

"Independent" means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110;

"Internal Auditor" means the person employed or engaged by the Corporation to perform the internal audit function of the Corporation;

"Management" means the senior officers of the Corporation;

"MD&A" means the Corporation's management discussion and analysis prepared in accordance with National Instrument 51-102F1 in respect of the Corporation's annual and interim financial statements; and

"Member" means a Director appointed to the Committee.

Composition and Meetings

1. The Committee shall be appointed annually by the Board and shall be comprised of three (3) or more Directors; each of whom is Independent and Financially Literate and none of whom is a member of Management or an employee of the Corporation or of any affiliate of the Corporation.

2. The Board shall appoint a Chair of the Committee on the recommendation of the Corporation's Governance and Nominating Committee, or such other committee as the Board may authorize.

3. The Committee shall meet at least four (4) times each year and shall meet at such other times during the year as it deems appropriate. Meetings of the Committee shall be held at the call of: (i) the Chair of the Committee, or (ii) any two (2) Members, or (iii) the External Auditor.

4. The President and Chief Executive Officer, the Vice President, Finance and Chief Financial Officer, the External Auditor and the Internal Auditor shall receive notice of, and (unless otherwise determined by the Chair of the Committee) shall attend all meetings of the Committee.

5. A quorum at any meeting of the Committee shall be three (3) Members.

6. The Chair of the Committee shall act as chair of all meetings of the Committee at which the Chair is present. In the absence of the Chair from any meeting of the Committee, the Members present at the meeting shall appoint one of their Members to act as Chair of the meeting.

7. Unless otherwise determined by the Chair of the Committee, the Secretary of the Corporation shall act as secretary of all meetings of the Committee.

Oversight of the External Audit and the Accounting and Financial Reporting and Disclosure Processes and Policies

The primary purpose of the Committee is oversight of the Corporation's external audit and the accounting and financial reporting and disclosure processes and policies on behalf of the Board. Management of the Corporation is responsible for maintaining appropriate accounting and financial reporting principles, policies, internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations. Management is responsible for the preparation and integrity of the financial statements of the Corporation.

1. Oversight of the External Audit

   The oversight of the external audit pertains to the audit of the Corporation's annual financial statements.

   1.1. The Committee is responsible for the evaluation and recommendation of the External Auditor to be proposed by the Board for appointment by the shareholders.

   1.2. In advance of each audit, the Committee shall review the External Auditor's audit plan including the general approach, scope and areas subject to risk of material misstatement.

   1.3. The Committee is responsible for approving the terms of engagement and fees of the External Auditor.

   1.4. The Committee shall review and discuss the Corporation's annual audited financial statements, together with the External Auditor's report thereon, and MD&A with Management and the External Auditor to gain reasonable assurance as to the accuracy, consistency and completeness thereof. The Committee shall meet privately with the External

Auditor. The Committee shall oversee the work of the External Auditor and resolve any disagreements between Management and the External Auditor.

1.5. The Committee shall use reasonable efforts, including discussion with the External Auditor, to satisfy itself as to the External Auditor's independence as defined in the CICA Assurance Handbook Section 5751.

2. Oversight of the Accounting and Financial Reporting and Disclosure Processes

2.1. The Committee shall recommend the annual audited financial statements together with the MD&A for approval by the Board.

2.2. The Committee shall review the interim unaudited financial statements with the External Auditor and Management, together with the External Auditor's review engagement report thereon.

2.3. The Committee shall review and approve publication of the interim unaudited financial statements, together with the interim MD&A and earnings media release on behalf of the Board.

2.4. The Committee shall review and recommend approval by the Board of the Corporation's AIF, Management Information Circular, any prospectus and other financial information or disclosure documents to be issued by the Corporation prior to their public release.

2.5. The Committee shall use reasonable efforts to satisfy itself as to the integrity of the Corporation's financial information systems, internal control over financial reporting and the competence of the Corporation's accounting personnel and senior financial management responsible for accounting and financial reporting.

2.6. The Committee shall be responsible for the oversight of the Internal Auditor.

3. Oversight of the Audit Committee Mandate and Policies

On a periodic basis, the Committee shall review and report to the Board on the Audit Committee Mandate as well as on the following policies:

3.1. Reporting Allegations of Suspected Improper Conduct and Wrongdoing Policy;

3.2. Derivative Financial Instruments and Hedging Policy;

3.3. Pre-Approval of Audit and Non-Audit Services Policy;

3.4. Hiring of Employees from Independent Auditing Firms Policy;

3.5. The Internal Audit Role and Function Policy; and

3.6. any other policies that may be established, from time to time, relating to accounting and financial reporting and disclosure processes; oversight of the external audit of the Corporation's financial statement; and oversight of the internal audit function.

Reporting

The Chair of the Committee, or another designated Member, shall report to the Board at each regular meeting on those matters which were dealt with by the Committee since the last regular meeting of the Board.

Other

1. The Committee shall perform such other functions as may, from time to time, be assigned to the Committee by the Board.

2. The Committee may approve, in circumstances that it considers appropriate, the engagement by the Committee or any Director of outside advisors or persons having special expertise at the expense of the Corporation.

11.3 Pre-Approval Policies and Procedures

The Audit Committee has established a policy which requires pre-approval of all audit and non-audit services provided to the Corporation and its subsidiaries by the Corporation's External Auditor. The Pre-Approval of Audit and Non-Audit Services Policy describes the services which may be contracted from the External Auditor and the limitations and authorization procedures related thereto. This policy defines services such as bookkeeping, valuations, internal audit and management functions which may not be contracted from the External Auditor and establishes an annual limit for permissible non-audit services not greater than the total fee for audit services. Audit Committee pre-approval is required for all audit and non-audit services.

11.4 External Auditor Service Fees

Fees incurred by the Corporation for work performed by Ernst & Young LLP, the Corporation's External Auditors, during each of the last two fiscal years for audit, audit-related, tax and non-audit services were as follows:

Fortis
External Auditor Service Fees
($ thousands)

Ernst & Young LLP	**2009**	2008
Audit Fees	**$ 2,279.8**	$ 2,467.3
Audit-Related Fees	**855.2**	853.0
Tax Fees	**353.5**	125.8
Total	**$ 3,488.5**	$ 3,446.1

The decrease in audit fees in 2009, as compared to 2008, primarily related to the requirement for additional year-end audit work in 2008 associated with the change in Caribbean Utilities fiscal year end from April 30 to December 31. The increase in tax fees in 2009, as compared to 2008, was due to tax work associated with the corporate reorganization of FortisUS Energy and work performed in relation to the adoption of amended CICA Handbook Section 3465, *Income Taxes,* by the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power in 2009.

12.0 TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares and First Preference Shares of Fortis is Computershare Trust Company of Canada in Halifax, Montréal and Toronto.

Computershare Trust Company of Canada
9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
E: service@computershare.com
W: www.computershare.com/fortisinc

13.0 AUDITORS

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants, The Fortis Building, 7th Floor, 139 Water Street, St. John's, NL, A1C 1B2. The financial statements of the Corporation for the fiscal year ended December 31, 2009 have been audited by Ernst & Young LLP. Ernst & Young LLP report that they are independent of the Corporation in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Newfoundland.

14.0 ADDITIONAL INFORMATION

Reference is made to the MD&A on pages 20 through 81 of the 2009 Fortis Inc. Annual Report to Shareholders, which pages are incorporated herein by reference. Additional information relating to the Corporation can be found on SEDAR at www.sedar.com.

Further additional information, including officers' and directors' remuneration and indebtedness, principal holders of the securities of Fortis, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in the Management Information Circular of Fortis dated March 22, 2010 for the May 4, 2010 Annual Meeting of Shareholders. Additional financial information is also provided in the comparative consolidated financial statements and MD&A of Fortis for the year ended December 31, 2009.

Requests for additional copies of the above-mentioned documents, as well as the 2009 Annual Information Form, should be directed to the Corporate Secretary, Fortis, P.O. Box 8837, St. John's, NL, A1B 3T2 (telephone: 709.737.2800). In addition, such documentation and additional information relating to the Corporation is contained on the Corporation's website at www.fortisinc.com.

FORTIS INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2010

March 7, 2011

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2010

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DEFINITIONS OF CERTAIN TERMS

Certain terms used in this Annual Information Form are defined below:

"2010 Annual Information Form" means this Fortis Inc. Annual Information Form in respect of the year ended December 31, 2010;

"2010 Audited Consolidated Financial Statements" means the audited comparative consolidated financial statements of Fortis Inc. as at and for the year ended December 31, 2010 and related notes thereto;

"Abitibi" means AbitibiBowater Inc.;

"Algoma Power" means Algoma Power Inc.;

"AUC" means Alberta Utilities Commission;

"BAL" means Belize Aquaculture Limited;

"BC Hydro" means BC Hydro and Power Authority;

"BCUC" means British Columbia Utilities Commission;

"BELCOGEN" means Belize Cogeneration Energy Limited;

"BECOL" means Belize Electric Company Limited;

"Belize Electricity" means Belize Electricity Limited;

"BEPC" means Brilliant Expansion Power Corporation;

"BEWU" means Belize Energy Workers Union;

"Board" means Board of Directors of Fortis Inc.;

"BPC" means Brilliant Power Corporation;

"BZ" means Belizean currency, which is pegged to the United States currency (BZ$2.00=US$1.00);

"Canadian GAAP" means Canadian generally accepted accounting principles;

"Canadian Niagara Power" means Canadian Niagara Power Inc.;

"Caribbean Utilities" means Caribbean Utilities Company, Ltd.;

"CAW" means Canadian Auto Workers-Retail/Wholesale;

"CEA" means Canadian Electricity Association;

"CEP" means Communications, Energy and Paperworkers Union of Canada;

"CFE" means Comisión Federal de Electricidad;

"CICA" means Canadian Institute of Chartered Accountants;

"COPE" means Canadian Office & Professional Employees Union;

"Cornwall Electric" means Cornwall Street Railway, Light and Power Company, Limited;

"Corporation" means Fortis Inc.;

"CPA" means Canal Plant Agreement;

"CPC/CBT" means Columbia Power Corporation and Columbia Basin Trust;

"CUPE" means Canadian Union of Public Employees;

"DBRS" means DBRS Limited;

"EMS" means environmental management system;

"Exchange Act" means the *U.S. Securities Exchange Act of 1934*, as amended;

"Exploits Partnership" means Exploits River Hydro Partnership between Abitibi and Fortis Properties;

"External Auditor" means the firm of chartered accountants registered with the Canadian Public Accountability Board or its successor and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

"Fortis" means Fortis Inc.;

"FortisAlberta" means FortisAlberta Inc.;

"FortisAlberta Holdings" means FortisAlberta Holdings Inc.;

"FortisBC" means, collectively, the operations of FortisBC Inc. and its parent company, Fortis Pacific Holdings Inc., but excluding its wholly owned partnership, Walden Power Partnership;

"FortisOntario" means, collectively, the operations of Canadian Niagara Power, Cornwall Electric and Algoma Power. Canadian Niagara Power's accounts include the operation of the electricity distribution business of Port Colborne Hydro Inc.;

"FortisOntario Inc." means the successor to Canadian Niagara Power Company, Limited and the parent company of Canadian Niagara Power, Cornwall Electric and Algoma Power;

"Fortis Pacific Holdings" means Fortis Pacific Holdings Inc.;

"Fortis Properties" means Fortis Properties Corporation;

"Fortis Turks and Caicos" means, collectively, P.P.C. Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd.;

"FortisUS Energy" means FortisUS Energy Corporation;

"FortisWest" means FortisWest Inc.;

"GHG" means greenhouse gas;

"GWh" means gigawatt hour(s);

"Hydro One" means Hydro One Networks Inc.;

"IASB" means International Accounting Standards Board;

"IBEW" means International Brotherhood of Electrical Workers;

"IESO" means Independent Electricity System Operator of Ontario;

"IFRS" means International Financial Reporting Standards;

"ISO" means International Organization for Standardization;

"June 2008 Final Decision" means the Public Utilities Commission's (Belize) June 2008 Final Decision on Belize Electricity's 2008/2009 Rate Application;

“kWh” means kilowatt hour(s);

“MD&A” means the Corporation’s Management Discussion and Analysis, located on pages 8 through 69 of the Corporation’s 2010 Annual Report to Shareholders, prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations,* in respect of the Corporation’s annual financial statements for the year ended December 31, 2010;

“Management” means, collectively, senior officers of the Corporation;

“Maritime Electric” means Maritime Electric Company, Limited;

“Moody’s” means Moody’s Investors Service;

“MW” means megawatt(s);

“NB Power” means New Brunswick Power Corporation;

“Newfoundland Hydro” means Newfoundland and Labrador Hydro;

“Newfoundland Power” means Newfoundland Power Inc.;

“Other Canadian Electric Utilities” means, collectively, the operations of FortisOntario and Maritime Electric;

“PCB” means polychlorinated biphenyl;

“PJ” means petajoule(s);

“Point Lepreau” means NB Power Point Lepreau Nuclear Generating Station;

“Port Colborne Hydro” means Port Colborne Hydro Inc.;

“PUB” means Newfoundland and Labrador Board of Commissioners of Public Utilities;

“PUC” means Public Utilities Commission (Belize);

“S&P” means Standard & Poor’s;

“SEC” means U.S. Securities and Exchange Commission;

“Teck Metals” means Teck Metals Ltd.;

“Terasen Gas companies” means, collectively, the operations of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.;

“Terasen” means Terasen Inc., the holding company of the Terasen Gas companies;

“TGI” means Terasen Gas Inc.;

“TGVI” means Terasen Gas (Vancouver Island) Inc.;

“TGWI” means Terasen Gas (Whistler) Inc.;

“TJ” means terajoule(s);

“UFCW” means United Food and Commercial Workers;

“US GAAP” means United States generally accepted accounting principles;

“USW” means United Steel Workers;

“Walden” means Walden Power Partnership;

"**Waneta Expansion"** means the 335-MW hydroelectric generating facility being constructed adjacent to the existing Waneta Plant on the Pend d'Oreille River in British Columbia;

"Waneta Partnership" means the Waneta Expansion Limited Partnership between CPC/CBT and Fortis;

"Whistler" means the Resort Municipality of Whistler.

1.0 CORPORATE STRUCTURE

The 2010 Annual Information Form has been prepared in accordance with National Instrument 52-102 - *Continuous Disclosure Obligations*. Financial information has been prepared in accordance with Canadian GAAP and is presented in Canadian dollars unless otherwise specified.

Except as otherwise stated, the information in the 2010 Annual Information Form is given as of December 31, 2010.

Fortis includes forward-looking information in the 2010 Annual Information Form within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide Management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. 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 2010 Annual Information Form, including the 2010 MD&A incorporated herein by reference, includes, but is not limited to, statements regarding: the expected total capital cost for the construction of the Waneta Expansion and its expected completion date; organic earnings' growth for the Corporation's regulated utilities in Canada is expected to be primarily driven by rate base growth at FortisAlberta and FortisBC; the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the expectation that the Corporation and its utilities will continue to have reasonable access to capital in the near to medium terms; the expected 2% growth in electricity sales for 2011 at the Corporation's regulated utilities in the Caribbean; the expected average annual energy production from the Macal River in Belize; the expected timing of the close of the sale of the joint-use poles at Newfoundland Power; consolidated forecast gross capital expenditures for 2011 and in total over the next five years; the nature, timing and amount of certain capital projects and their expected costs and time to complete; the expectation that the subsidiaries will be able to source the cash required to fund their 2011 capital expenditure programs; expected consolidated long-term debt maturities and repayments in 2011 and on average annually over the next five years; no material increase in consolidated interest expense and/or fees associated with renewed and extended credit facilities is expected in 2011; expected earnings' contribution from Belize Electricity to the consolidated earnings of Fortis in the course of normal operations; the estimated impact a decrease in revenue at Fortis Properties' Hospitality Division would have on basic earnings per common share; no expected material adverse credit rating actions in the near term; the expected impact of a change in the US dollar-to-Canadian dollar foreign exchange rate on basic earnings per common share in 2011; the expectation that counterparties to the Terasen Gas companies' gas derivative contracts will continue to meet their obligations; the expectation that Fortis will become an SEC Issuer by December 31, 2011; the expected impact of the transition to US GAAP; and the expectation of an increase in consolidated defined benefit net pension cost for 2011. The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major event; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no material capital project and financing cost overrun or delay related to the construction of the Waneta Expansion; no significant decline in capital spending in 2011; no severe and prolonged downturn in economic conditions; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in interest rates and foreign exchange rates; no significant variability in interest rates; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas and fuel supply; the continued ability to fund defined benefit pension plans; the absence of significant changes in government energy plans and environmental laws that may materially affect the operations and cash flows of the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; maintenance of information technology infrastructure; favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program. 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. Factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory risk; operating and maintenance risks; capital project budget overrun, completion and financing risk in the Corporation's non-regulated business; economic conditions; capital resources and liquidity risk; weather and seasonality; commodity price risk; derivative financial instruments and hedging; interest rate risk; counterparty risk; competitiveness of natural gas; natural gas and fuel supply; defined benefit pension plan performance and funding requirements; risks related to the development of the TGVI franchise; environmental risks; insurance coverage risk; loss of licences and permits; loss of service area; the risk of transition to new accounting standards that do not recognize the impact of rate regulation; changes in tax legislation; information technology infrastructure; an ultimate resolution of the expropriation of the assets of the Exploits Partnership that differs from what is currently expected by management; an unexpected outcome of legal proceedings currently against the Corporation; relations with First Nations; labour relations; and human resources. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Business Risk Management" in the MD&A.

All forward-looking information in the 2010 Annual Information Form is qualified in its entirety by the above cautionary statements 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.

1.1 Name and Incorporation

Fortis is a holding company that was incorporated as 81800 Canada Ltd. under the *Canada Business Corporations Act* on June 28, 1977 and continued under the *Corporations Act* (Newfoundland and Labrador) on August 28, 1987.

The articles of incorporation of the Corporation were amended to: (i) change its name to Fortis on October 13, 1987; (ii) set out the rights, privileges, restrictions and conditions attached to the Common Shares on October 15, 1987; (iii) designate 2,000,000 First Preference Shares, Series A on September 11, 1990; (iv) replace the class rights, privileges, restrictions and conditions attaching to the First Preference Shares and the Second Preference Shares on July 22, 1991; (v) designate 2,000,000 First Preference Shares, Series B on December 13, 1995; (vi) designate 5,000,000 First Preference Shares, Series C on May 27, 2003; (vii) designate 8,000,000 First Preference Shares, Series D and First Preference Shares, Series E on January 23, 2004; (viii) amend the redemption provisions attaching to the First Preference Shares, Series D on July 15, 2005; (ix) designate 5,000,000 First Preference Shares, Series F on September 22, 2006; (x) designate 9,200,000 First Preference Shares, Series G on May 20, 2008; and (xi) designate 10,000,000 First Preference Shares, Series H on January 20, 2010.

Fortis redeemed all of its outstanding First Preference Shares, Series A and First Preference Shares, Series B on September 30, 1997 and December 2, 2002, respectively. On June 3, 2003, Fortis issued 5,000,000 First Preference Shares, Series C. On January 29, 2004, Fortis issued 8,000,000 First Preference Units, each unit consisting of one First Preference Share, Series D and one Warrant. During 2004, 7,993,500 First Preference Units were converted into 7,993,500 First Preference Shares, Series E and 6,500 First Preference Shares, Series D remained outstanding. On September 20, 2005, the 6,500 First Preference Shares, Series D were redeemed by the Corporation. On September 28, 2006, Fortis issued 5,000,000 First Preference Shares, Series F. On May 23, 2008, Fortis issued 8,000,000 First Preference Shares, Series G and on June 4, 2008 issued an additional 1,200,000 First Preference Shares, Series G, following the exercise of an over-allotment option in connection with the offering of the 8,000,000 First Preference Shares, Series G. On January 26, 2010, Fortis issued 10,000,000 First Preference Shares, Series H.

The corporate head and registered office of Fortis is located at the Fortis Building, Suite 1201, 139 Water Street, P.O. Box 8837, St. John's, NL, Canada, A1B 3T2.

1.2 Inter-Corporate Relationships

Fortis is principally an international distribution utility holding company. Its regulated holdings include electric distribution utilities in five Canadian provinces and three Caribbean countries and a natural gas distribution utility in British Columbia. As at December 31, 2010, regulated utility assets comprised approximately 92% of the Corporation's total assets, with the balance primarily comprised of non-regulated generation assets, mainly hydroelectric, across Canada and in Belize and Upper New York State, and hotels and commercial office and retail space primarily in Atlantic Canada.

The following table lists the principal subsidiaries of the Corporation, their jurisdictions of incorporation and the percentage of votes attaching to voting securities held directly or indirectly by the Corporation as at March 7, 2011. This table excludes certain subsidiaries, the total assets of which individually constituted less than 10% of the Corporation's consolidated assets as at December 31, 2010, or the total revenue of which individually constituted less than 10% of the Corporation's 2010 consolidated revenue. Additionally, the principal subsidiaries together comprise approximately 80% of the Corporation's consolidated assets as at December 31, 2010 and approximately 75% of the Corporation's 2010 consolidated revenue.

Principal Subsidiaries		
Subsidiary	**Jurisdiction of Incorporation**	**Percentage of votes attaching to voting securities beneficially owned, controlled or directed by the Corporation**
Terasen	British Columbia	100
FortisAlberta [(1)]	Alberta	100
FortisBC Inc. [(2)]	British Columbia	100
Newfoundland Power	Newfoundland and Labrador	94.0 [(3)]

(1) FortisAlberta Holdings, an Alberta corporation, owns all of the shares of FortisAlberta. FortisWest, a Canadian corporation, owns all of the shares of FortisAlberta Holdings. Fortis owns all of the shares of FortisWest.

(2) Fortis Pacific Holdings, a British Columbia corporation, owns all of the shares of FortisBC Inc. FortisWest, a Canadian corporation, owns all of the shares of Fortis Pacific Holdings. Fortis owns all of the shares of FortisWest.

(3) Fortis owns all of the common shares; 1,713 First Preference Shares, Series A; 34,531 First Preference Shares, Series B; 13,700 First Preference Shares, Series D and 182,300 First Preference Shares, Series G of Newfoundland Power which, at March 7, 2011, represented 94.0% of its voting securities. The remaining 6.0% of Newfoundland Power's voting securities consist of First Preference Shares, Series A, B, D and G which are primarily held by the public.

2.0 GENERAL DEVELOPMENT OF THE BUSINESS

2.1 Three-Year History

Over the past three years, Fortis has experienced growth in its business operations. Total assets have grown 25% from $10.3 billion as at December 31, 2007 to $12.9 billion as at December 31, 2010. The Corporation's shareholders' equity has also grown more than 45% from $2.8 billion as at December 31, 2007 to $4.1 billion as at December 31, 2010. Net earnings attributable to common equity shareholders' have increased from $193 million in 2007 to $285 million in 2010.

The growth in business operations reflects the Corporation's profitable growth strategy for its principal businesses of regulated gas and electricity distribution. This strategy includes a combination of growth through acquisitions and organic growth through the Corporation's consolidated capital expenditure program.

Over the past three years, Fortis increased its regulated utility investments in Canada through the acquisition of Algoma Power for $75 million, in October 2009, and increased its ownership interest in Caribbean Utilities from approximately 54% in 2007 to approximately 59% held as at December 31, 2010. Algoma Power is a regulated electric distribution utility servicing approximately 12,000 customers in the District of Algoma in Ontario. The Corporation also increased its non-regulated investments, over the last three years, through the acquisition of three hotels in Canada, the construction of the Vaca hydroelectric generating facility in Belize, which was completed in March 2010, and the commencement of construction of the Waneta Expansion late in 2010.

Organic growth at the regulated utilities has been driven by the capital expenditure programs at FortisAlberta, FortisBC and the Terasen Gas companies. Total assets at FortisAlberta, FortisBC and Terasen have grown by approximately 56%, 32% and 18%, respectively, over the past three years.

2.2 Outlook

Operations

The Corporation maintains a profitable growth strategy for its principal businesses of regulated gas and electricity distribution, as well as for its non-regulated operations. This strategy includes a combination of growth through acquisitions and organic growth through the Corporation's consolidated capital expenditure program, including investments in non-regulated hydroelectric generation projects as described above.

Over the next five years, consolidated gross capital expenditures are expected to approach $5.5 billion. Approximately 63% of the capital spending is expected to be incurred at the regulated electric utilities, driven by FortisAlberta and FortisBC. Approximately 20% and 17% of the capital spending is expected to be incurred at the regulated gas utilities and at non-regulated operations, respectively. Capital expenditures at the regulated utilities are subject to regulatory approval.

Gross consolidated capital expenditures for 2011 are expected to be approximately $1.2 billion, as summarized in the following table. 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.

Forecast Gross Consolidated Capital Expenditures (1)
Year Ending December 31, 2011

	($ millions)
Terasen Gas Companies	281
FortisAlberta (2)	420
FortisBC	99
Newfoundland Power	73
Other Canadian Electric Utilities	46
Regulated Electric Utilities – Caribbean	83
Non-Regulated Utility (3)	183
Fortis Properties	27
Total	**1,212**

(1) *Relates to forecast cash payments to acquire or construct utility capital assets, income producing properties and intangible assets, as would be reflected on the consolidated statement of cash flows. Includes forecast asset removal and site restoration expenditures, net of salvage proceeds, for those utilities where such expenditures are permissible in rate base in 2011.*
(2) *Includes forecast payments to be made to the Alberta Electric System Operator for investment in transmission capital projects*
(3) *Includes forecast non-regulated generation, mainly related to the Waneta Expansion, and corporate capital expenditures*

The Corporation's subsidiaries expect to have reasonable access to long-term capital in 2011 to fund their capital expenditure programs.

The Corporation continues to pursue acquisitions for profitable growth, focusing on strategic opportunities to acquire regulated natural gas and electric utilities in the United States and Canada. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

Future Accounting Changes

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 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 the continued uncertainty around the timing and adoption of a rate-regulated accounting standard by the IASB. As a qualifying entity with rate-regulated activities, Fortis has elected to avail of the one-year deferral and, therefore, will continue 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 the continued uncertainty around the timing and adoption of a rate-regulated accounting standard by the IASB, Fortis has evaluated the option of adopting US GAAP effective January 1, 2012. Canadian rules allow a reporting issuer to prepare and file its financial statements in accordance with US GAAP by qualifying as an 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 *Exchange Act*; or (ii) is required to file reports under Section 15(d) of the *Exchange Act*. The Corporation has developed and initiated a plan to become an SEC Issuer by December 31, 2011. As an SEC Issuer, Fortis will then be permitted to prepare and file its consolidated financial statements in accordance with US GAAP. Barring a change that will provide certainty as to the Corporation's ability to recognize regulatory assets and liabilities under IFRS, Fortis expects to prepare its consolidated financial statements in accordance with US GAAP for all interim and annual periods beginning on or after January 1, 2012.

The adoption of US GAAP in 2012 is expected to result in fewer significant changes in the Corporation's accounting policies as compared to those that may have resulted with the adoption of IFRS. The Corporation's application of Canadian GAAP currently relies on US GAAP for guidance on accounting for rate-regulated activities, which 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. Fortis believes that the continued application of rate-regulated accounting, and the associated recognition of regulatory assets and liabilities under US GAAP, more accurately reflects the impact that rate regulation has on the Corporation's consolidated financial position and results of operations. Should the Corporation not be successful in becoming an SEC Issuer by December 31, 2011, Fortis will be required to adopt IFRS effective January 1, 2012. In the absence of an accounting standard for rate-regulated activities being established by the IASB, a transition to IFRS would likely result in the derecognition of some, or perhaps all, of the Corporation's regulatory assets and liabilities, and could result in significant volatility in the Corporation's consolidated earnings, as recognized under IFRS, from those otherwise recognized under US GAAP or previous Canadian GAAP.

3.0 DESCRIPTION OF THE BUSINESS

Fortis is principally an international distribution utility holding company. Its core business is highly regulated and is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets, and commercial office and retail space and hotels, which are treated as two separate segments. The Corporation's reporting segments allow Management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. Each reporting segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The business segments of the Corporation are: (i) Regulated Gas Utilities - Canadian; (ii) Regulated Electric Utilities - Canadian; (iii) Regulated Electric Utilities - Caribbean; (iv) Non-Regulated – Fortis Generation; (v) Non-Regulated - Fortis Properties; and (vi) Corporate and Other.

The following sections describe the operations included in each of the Corporation's reportable segments.

3.1 Regulated Gas Utilities - Canadian

3.1.1 *Terasen Gas Companies*

The Regulated Gas Utilities - Canadian segment comprises the natural gas transmission and distribution business of the Terasen Gas companies.

TGI is the largest distributor of natural gas in British Columbia, serving more than 846,000 residential, commercial and industrial customers in a service area that extends from Vancouver to the Fraser Valley and the interior of British Columbia.

TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island, and the distribution system on Vancouver Island and along the Sunshine Coast of British Columbia, serving more than 100,000 residential, commercial and industrial customers.

In addition to providing transmission and distribution services to customers, TGI and TGVI also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through TGI's Southern Crossing pipeline, from Alberta.

TGWI owns and operates the natural gas distribution system in Whistler, British Columbia, which provides service to approximately 2,600 residential and commercial customers.

The Terasen Gas companies own and operate approximately 46,500 kilometres of natural gas distribution and transmission pipelines and met a peak day demand of 1,421 TJ in 2010.

Market and Sales

The Terasen Gas companies' annual customer gas volumes decreased to 193,022 TJ in 2010 from 207,230 TJ in 2009. Revenue was approximately $1.5 billion in 2010 compared to $1.7 billion in 2009.

The following table compares the composition of 2010 and 2009 revenue and gas volumes by customer class of the Terasen Gas companies.

Terasen Gas Companies
Revenue and Gas Volumes by Customer Class

	Revenue *(%)*		**PJ Volumes** *(%)*	
	2010	2009	**2010**	2009
Residential	**57.2**	56.9	**36.2**	37.6
Commercial	**33.8**	33.9	**23.9**	22.9
Small industrial	**1.4**	1.7	**1.3**	2.8
Large industrial and other	**0.1**	0.1	**0.1**	0.1
	92.5	92.6	**61.5**	63.4
Transportation and other	**7.5**	7.4	**38.5**	36.6
Total	**100.0**	100.0	**100.0**	100.0

Gas Purchase Agreements

In order to acquire supply resources that ensure reliable natural gas deliveries to its customers, the Terasen Gas companies purchase supply from a select list of producers, aggregators and marketers by adhering to strict standards of counterparty creditworthiness and contract execution and/or management procedures. TGI contracts for approximately 102 PJ of baseload and seasonal supply, of which 75 PJ is delivered off the Spectra Energy transmission system. Approximately 10 PJ is comprised primarily of Alberta-sourced supply transported into British Columbia via TransCanada Pipeline Limited's Alberta and British Columbia systems. The remaining 17 PJ of baseload and seasonal supply is sourced at Sumas, British Columbia. TGVI contracts for approximately 11 PJ of annual supply comprised of base load and seasonal contracts, of which approximately 9 PJ is delivered off the Spectra Energy transmission system and 2 PJ is sourced directly at Sumas.

Through the operation of regulatory deferrals, any difference between forecast cost of natural gas purchases, as reflected in customer rates, and the actual cost of natural gas purchases is recovered from, or refunded to, customers in future rates. The majority of supply contracts in the current portfolio are seasonal for either the summer period (April to October) or winter period (November to March) with a few contracts one year or longer in length.

The Spectra Energy transmission and TransCanada Pipeline Limited transportation tolls are regulated by the National Energy Board, whose responsibilities include regulating pipeline tolls. The Terasen Gas companies pay both fixed and variable charges for use of the pipelines, which are recovered through rates paid by its customers. TGI contracts pipeline capacity to ensure the Company meets its obligation to supply customers under all reasonable demand scenarios while providing diversity in its gas portfolio.

Peak Shaving Arrangements

TGI and TGVI incorporate peak shaving and gas storage facilities into its portfolio to:

i. supplement baseload supply in the winter months while injecting excess baseload supply to refill storage in the summer months;
ii. eliminate the risk of supply shortages during cooler weather and peak throughput day;
iii. effectively manage the cost of gas during winter months; and
iv. balance daily supply and demand on the distribution system.

The Terasen Gas companies' peak shaving and storage assets and contracts for 2010 included up to 30 PJ in storage capacity at various locations throughout British Columbia, Alberta and the Pacific Northwest region of the United States. These storage facilities and supply from peak shaving contracts can deliver a maximum daily rate of 0.7 PJ on a combined basis during the coldest months of December through February.

TGVI maintains storage contracts with Unocal Canada Limited at the Aitken Creek Storage facility in Northern British Columbia and Northwest Natural Gas Company at the Mist Storage facility in Oregon, United States. TGVI's Aitken Creek and Mist storage facilities storage contracts consist of 2.8 PJ of combined storage capacity and have the ability to provide up to 40 TJ per day of combined daily deliverability during cooler weather or peak day conditions. TGVI also has access to an estimated 30 TJ of daily peak supply deliverability from various peak supply arrangements.

Off-System Sales

TGI is in its fifteenth year of off-system sales activities, in which any daily excess supply of gas is sold at the market-spot rate that allows for the recovery or mitigation of costs on unutilized supply and/or pipeline capacity. In 2009/2010 TGI marketed approximately 30 PJ of surplus gas and 42 PJ of excess pipeline capacity for a net pre-tax recovery of approximately $152 million. Through the Gas Supply Mitigation Incentive Plan established with the BCUC, approximately $1 million (pre-tax) of these benefits accrued to shareholders with the remainder flowing through to customers in the form of reduced rates for natural gas costs.

The BCUC has approved the 2010/2011 incentive mechanism and the Company continues to undertake mitigation activities.

Unbundling

Over the past several years, TGI, the BCUC and other interested parties have laid the groundwork for the introduction of natural gas commodity unbundling in British Columbia. On November 1, 2004, commercial customers of TGI became eligible to buy their natural gas commodity supply directly from third-party suppliers. TGI continues to provide delivery of the natural gas. Approximately 81,000 commercial customers are eligible to participate in commodity unbundling. By December 31, 2010, approximately 18,000 customers had elected to participate in this program.

During 2006 the BCUC approved the offering of commodity supply choice to residential customers. The BCUC agreed to open a portion of the province of British Columbia's residential natural gas market to competition, allowing homeowners to sign long-term fixed-price contracts for natural gas with companies other than TGI, effective May 2007. Consumers had the option to remain with TGI or sign with another market participant, in which case they began receiving gas at that market participant's rate beginning in November 2007. TGI continues to provide delivery service to unbundled customers and delivery margins are not expected to be impacted by migration of residential customers to alternative commodity suppliers. Approximately 762,500 residential customers are eligible to participate in commodity unbundling. By December 31, 2010, approximately 115,000 customers had elected to participate in this program.

Legal Proceedings

During 2007 and 2008, a non-regulated subsidiary of Terasen received Notices of Assessment from Canadian Revenue Agency for additional taxes related to the taxations years 1999 through 2003. The exposure has been fully provided for in the Corporation's 2010 Audited Consolidated Financial Statements. Terasen has begun the appeal process associated with the assessments.

In 2009 Terasen was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to the rupture in July 2007 of an oil pipeline owned and operated by Kinder Morgan. Terasen has filed a statement of defence but the claim is in its early stages. During the second quarter of 2010, Terasen was added as a third party in all of the related actions and all claims are expected to be tried at the same time. The amount and outcome of the actions are indeterminable at this time and, accordingly, no amount has been accrued in the Corporation's 2010 Audited Consolidated Financial Statements.

Human Resources

As at December 31, 2010, the Terasen Gas companies employed 1,480 full-time equivalent employees. Approximately 71% of the employees are represented by IBEW, Local 213, and COPE, Local 378, under collective agreements that expire on March 31, 2011 and March 31, 2012, respectively.

Recent Developments

On March 1, 2011, the Terasen Gas companies were renamed to commence operating under a common brand identity with FortisBC in British Columbia, Canada. As a result, the following name changes were made:

Names – Prior to March 1, 2011	**Names – Effective March 1, 2011**
Terasen Inc.	FortisBC Holdings Inc.
Terasen Gas Inc.	FortisBC Energy Inc.
Terasen Gas (Vancouver Island) Inc.	FortisBC Energy (Vancouver Island) Inc.
Terasen Gas (Whistler) Inc.	FortisBC Energy (Whistler) Inc.
Terasen Energy Services Inc.	FortisBC Alternative Energy Services Inc.

The common brand identity aligns with the approach of Terasen and FortisBC of ensuring an integrated focus and strategy in the delivery of energy to its customers.

3.2 Regulated Electric Utilities - Canadian

3.2.1 *FortisAlberta*

FortisAlberta is a regulated electric distribution utility in the province of Alberta. Its business is the ownership and operation of regulated electric distribution facilities that distribute electricity generated by other market participants from high-voltage transmission substations to end-use customers. FortisAlberta is not involved in the generation, transmission or direct sale of electricity. FortisAlberta owns and/or operates the electricity distribution system in a substantial portion of southern and central Alberta, totalling approximately 112,000 kilometres of distribution lines. The Company's distribution network serves approximately 491,000 customers, comprising residential, commercial, farm and industrial consumers of electricity, and met a peak demand of 2,555 MW in 2010.

Market and Sales

FortisAlberta's annual energy deliveries increased to 15,866 GWh in 2010 from 15,865 GWh in 2009. Revenue was $388 million in 2010 compared to $331 million in 2009.

The following table compares the composition of FortisAlberta's 2010 and 2009 revenue and energy deliveries by customer class.

FortisAlberta
Revenue and Energy Deliveries by Customer Class

	Revenue *(%)*		**GWh Deliveries** [(1)] *(%)*	
	2010	2009	**2010**	2009
Residential	**27.5**	28.8	**17.0**	16.9
Large commercial and industrial [(2)]	**18.5**	21.3	**61.3**	60.3
Farms	**11.5**	12.1	**7.5**	8.6
Small commercial	**9.9**	10.7	**7.9**	8.0
Small oilfield	**8.0**	8.8	**5.8**	5.8
Other [(3)]	**24.6**	18.3	**0.5**	0.4
Total	**100.0**	100.0	**100.0**	100.0

[(1)] *GWh percentages presented exclude FortisAlberta's GWh deliveries to "transmission-connected" customers. These deliveries were 7,100 GWh in 2010 and 6,757 GWh in 2009 and consisted primarily of energy deliveries to large-scale industrial customers directly connected to the transmission grid.*
[(2)] *Includes large oilfield customers*
[(3)] *Includes revenue from sources other than the delivery of energy, including that related to street-lighting services, rate riders, deferrals and adjustments*

Franchise Agreements

Most of FortisAlberta's residential, commercial and industrial customers, located within a city, town, or village boundary, are served through franchise agreements between the Company and the customers' municipality of residence. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta that are located in their municipal boundaries. In Alberta, the standard franchise agreement, which could include a franchise fee payable to the municipality, is generally for ten years and may be renewed for five years upon mutual consent of the parties. All municipal franchises are governed by legislation that requires the municipality or the utility to give notice and obtain AUC approval if it intends to terminate its franchise agreement. Any franchise agreement that is not renewed continues in effect until either the Company or the municipality terminates it with AUC permission. If a franchise agreement is terminated and the municipality subsequently exercises its right under the *Municipal Government Act* (Alberta) to purchase FortisAlberta's distribution network within the municipality's boundaries, the Company must be compensated. Compensation would include payment for FortisAlberta's assets on the basis of a methodology approved by the AUC.

Additionally, under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric distribution system expands its boundaries, the municipality can acquire the Company's assets in the annexed area. In such circumstances, the *Hydro and Electricity Energy Act* (Alberta) provides that the AUC may determine that the municipality should pay compensation to the Company for any facilities transferred on the basis of replacement cost less depreciation.

FortisAlberta has standardized, individual franchise agreements in place with 140 municipalities. Substantially all of these agreements expire between 2011 and 2017. The Company is in the process of extending or negotiating franchise agreements with these municipalities

Human Resources

As at December 31, 2010, FortisAlberta had 980 full-time equivalent employees. Approximately 75% of the employees of the Company are members of a labour association represented by United Utility Workers' Association, Local 200, under a three-year collective agreement that expires on December 31, 2013.

3.2.2 *FortisBC*

FortisBC includes FortisBC Inc., an integrated electric utility that owns a network of generation, transmission and distribution assets located in the southern interior of British Columbia. FortisBC Inc. serves a diverse mix of approximately 161,000 customers, of whom approximately 112,250 are served directly by the Company's assets while the remainder are served through the wholesale supply of power to municipal distributors. In 2010 FortisBC Inc. met a peak demand of 707 MW. Residential customers represent the largest customer class of the Company. FortisBC's transmission and distribution assets include approximately 7,000 kilometres of transmission and distribution lines and 64 substations.

FortisBC also includes operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals and BC Hydro, the 149-MW Brilliant hydroelectric plant and 120-MW Brilliant expansion plant, both owned by CPC/CBT, the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT, and the distribution system owned by the City of Kelowna.

Market and Sales

FortisBC has a diverse customer base composed primarily of residential, general service, industrial and municipal wholesale, and other industrial customers. Annual electricity sales were 3,046 GWh in 2010 compared to 3,157 GWh in 2009. Revenue increased to $266 million in 2010 from $253 million in 2009.

The following table compares the composition of FortisBC's 2010 and 2009 revenue and electricity sales by customer class.

FortisBC
Revenue and Electricity Sales by Customer Class

	Revenue *(%)*		**GWh Sales** *(%)*	
	2010	2009	**2010**	2009
Residential	**43.0**	44.0	**40.2**	41.0
General service	**24.3**	24.5	**23.2**	23.2
Wholesale	**19.5**	19.6	**28.9**	29.4
Industrial	**6.1**	5.5	**7.7**	6.4
Other [(1)]	**7.1**	6.4	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

[(1)] *Includes revenue from sources other than from the sale of electricity, including revenue of Fortis Pacific Holdings associated with non-regulated operating, maintenance and management services*

Generation and Power Supply

FortisBC Inc. meets the electricity supply requirements of its customers through a mix of its own generation and power purchase contracts. FortisBC Inc. owns four regulated hydroelectric generating plants on the Kootenay River with an aggregate capacity of 223 MW and annual energy output of approximately 1,591 GWh, which provide approximately 45% of the Company's energy needs and 30% of its peak capacity needs. FortisBC Inc. meets the balance of its requirements through a portfolio of long-term and short-term power purchase agreements. Since 1998, 11 of 15 FortisBC hydroelectric generation units have been subject to a life extension and upgrade program which is forecast to conclude in 2012.

FortisBC Inc.'s four hydroelectric generating facilities are governed by the CPA. The CPA is a multi-party agreement that enables the five separate owners of eight major hydroelectric generating plants, with a combined capacity of approximately 1,600 MW and located in relatively close proximity to each other, to coordinate the operation and dispatch of their plants.

The following table lists the plants and their owners.

Plant	Capacity (MW)	Owners
Canal Plant	580	BC Hydro
Waneta Dam	493	Teck Metals and BC Hydro [(1)]
Kootenay River System	223	FortisBC Inc.
Brilliant Dam and Expansion	269	BPC and BEPC
Total	**1,565**	

[(1)] *During 2010, BC Hydro acquired a one-third interest in the Waneta Dam.*

BPC, BEPC, Teck Metals and FortisBC Inc. are collectively defined in the CPA as the Entitlement Parties. 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 through the coordinated operation of storage reservoirs and generating plants, to generate more power from their respective generating resources than they could if they operated independently. Under the CPA, BC Hydro takes into its system all power actually generated by all seven plants owned by the Entitlement Parties. In exchange for permitting BC Hydro to determine the output of these facilities, each of the Entitlement Parties is contractually entitled to a fixed annual entitlement of capacity and energy from BC Hydro, which is currently based on 50-year historical water flows. The Entitlement Parties receive their defined entitlements irrespective of actual water flows to the Entitlement Parties' generating plants and are, accordingly, insulated from the risk of water availability. 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.

The majority of FortisBC Inc.'s remaining electricity supply is acquired through long-term power purchase contracts, consisting of the following:

i. a 149-MW long-term power purchase agreement with BPC terminating in 2056;
ii. a 200-MW power purchase agreement with BC Hydro terminating in 2013; and
iii. a number of small power purchase contracts with independent power producers.

The majority of these purchase contracts have been accepted by the BCUC and prudently incurred costs thereunder flow through to customers through FortisBC Inc.'s electricity rates.

Although FortisBC Inc. can currently meet the majority of its customer supply requirements from its own generation and the major power purchase agreements described above, there are instances where a portion of the customer load 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 incurred and accurately forecasted, are recovered through customer rates. During 2010 the Company has also 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.

In October 2010 the Corporation, in partnership with CPC/CBT, concluded definitive agreements to construct the Waneta Expansion. Fortis owns a controlling 51% interest in the Waneta Partnership and will operate and maintain the Waneta Expansion, through FortisBC, when it comes into service, which is expected in spring 2015. The Waneta Expansion will be included in the CPA and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing hydrologic risk associated with the project. The energy, approximately 630 GWh, (and associated capacity required to deliver such energy) for the Waneta Expansion will be sold to BC Hydro under a long-term energy purchase agreement which has been executed. The surplus capacity, equal to 234 MW on an average annual basis, will be sold to FortisBC Inc. over 40 years under the Waneta Expansion Capacity Agreement, which was accepted for filing by the BCUC in September 2010 and is expected to be executed by the parties in 2011. For additional information refer to Section 3.4 of this AIF.

Legal Proceedings

The British Columbia Ministry of Forests has alleged breaches of the Forest Practices Code and negligence relating to a fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC Inc. In addition, the Company has been served with a filed writ and statement of claim by private landowners in relation to the same matter. The Company is communicating with its insurers and has filed a statement of defence in relation to both of the actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the Corporation's 2010 Audited Consolidated Financial Statements.

Human Resources

As at December 31, 2010, FortisBC had 534 full-time equivalent employees. FortisBC has a collective agreement with COPE, Local 378, that expired on January 31, 2011 and a collective agreement with IBEW, Local 213, expiring on January 31, 2013. The two collective agreements cover approximately 76% of employees.

FortisBC and COPE have agreed in principle to explore amalgamating FortisBC's and TGI's collective agreements with COPE. The current collective agreement between FortisBC and COPE will remain in full effect until an amalgamation is agreed to or discussions cease. Should the parties be unable to reach an amalgamated agreement, the Company plans to commence negotiation for a revised collective agreement.

3.2.3 *Newfoundland Power*

Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving more than 243,000 customers, or 86%, of the province's electricity consumers. Newfoundland Power met a peak demand of 1,206 MW in 2010. The balance of the population is served by Newfoundland's other electric utility, Newfoundland Hydro, which also serves several larger industrial customers. Newfoundland Power owns and operates approximately 11,000 kilometres of transmission and distribution lines.

Market and Sales

Annual weather-adjusted electricity sales increased to 5,419 GWh in 2010 from 5,299 GWh in 2009. Revenue increased to $555 million in 2010 from $527 million in 2009.

The following table compares the composition of Newfoundland Power's 2010 and 2009 revenue and electricity sales by customer class.

Newfoundland Power
Revenue and Electricity Sales by Customer Class

	Revenue [1] *(%)*		**GWh Sales** [1] *(%)*	
	2010	2009	**2010**	2009
Residential	**60.2**	59.0	**61.1**	60.4
Commercial and Street Lighting	**36.3**	37.0	**38.9**	39.6
Other [2]	**3.5**	4.0	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) Revenue and electricity sales reflect weather-adjusted values pursuant to Newfoundland Power's weather normalization reserve.
(2) Includes revenue from sources other than from the sale of electricity, the most significant being joint-use of pole revenue

Power Supply

Approximately 93% of Newfoundland Power's energy requirements is purchased from Newfoundland Hydro. The principal terms of the supply arrangements with Newfoundland Hydro are regulated by the PUB on a basis similar to that upon which Newfoundland Power's service to its customers is regulated.

Newfoundland Power operates 30 small generating facilities, which generate approximately 7% of the electricity sold by Newfoundland Power. The Company's hydroelectric generating plants have a total capacity of 97 MW. The diesel plants and gas turbines have a total capacity of approximately 7 MW and 36 MW, respectively.

Legal Proceedings

The City of St. John's has given formal notice of its intention to terminate Newfoundland Power's rights to use the Mobile River watershed for the generation of electricity. The effective date of the notice to terminate the lease was March 1, 2009. The Company held these rights under a lease dated November 23, 1946, which was amended by an agreement dated October 21, 1949. The two hydroelectric generating plants affected by the lease have a combined capacity of approximately 12 MW and generate annual production of 49 GWh, representing less than 1% of the Company's total energy requirements. To exercise the termination provision of the lease, the City of St. John's is required to pay to the Company the value of all works and erections employed in the generation and transmission of electricity using the water of the Mobile River watershed. In accordance with the terms of the lease, an arbitration panel was appointed in 2008 for the purpose of determining the value of the affected assets. On March 9, 2009, the panel issued a ruling on certain preliminary questions. A majority of the panel ruled that termination of the lease will not be effective until payment to the Company of the value of the assets, and that the value of the payment is to be based on a valuation of the assets as a going concern, including the land and water rights.

The City of St. John's has applied to the Supreme Court of Newfoundland and Labrador to have the preliminary ruling of the arbitration panel set aside. On November 12, 2010, the Supreme Court issued a decision dismissing the City's application, and awarding court costs to Newfoundland Power. In December 2010 the city appealed the Supreme Court's decision to the Newfoundland and Labrador Court of Appeal. A hearing date for the appeal has not yet been set.

Human Resources

As at December 31, 2010, Newfoundland Power had 572 full-time equivalent employees, of which approximately 54% were members of bargaining units represented by IBEW, Local 1620.

The Company has two collective agreements governing its union employees represented by IBEW, Local 1620. Both collective agreements expire September 30, 2011.

Recent Developments

In December 2010 Newfoundland Power and Bell Aliant signed a new Support Structure Agreement, effective January 1, 2011, whereby Bell Aliant will buy back 40% of all joint-use poles and related infrastructure owned by Newfoundland Power for approximately $46 million. Newfoundland Power has filed an application with the PUB requesting approval of the transaction and expects the transaction to close in 2011.

3.2.4 Other Canadian Electric Utilities

Other Canadian Electric Utilities includes the operations of Maritime Electric and FortisOntario.

<u>Maritime Electric</u>
The Corporation, through FortisWest, holds all of the common shares of Maritime Electric. Maritime Electric is an integrated electric utility that directly supplies more than 74,000 customers, constituting 90% of electricity consumers on Prince Edward Island. Maritime Electric purchases most of the energy it distributes to its customers from NB Power, a provincial Crown Corporation, through various energy purchase agreements. Maritime Electric's system is connected to the mainland power grid via two submarine cables between Prince Edward Island and New Brunswick, which are leased from the Government of Prince Edward Island. Maritime Electric owns and operates generating plants

with a combined capacity of 150 MW on Prince Edward Island and met a peak demand of 207 MW in 2010. Maritime Electric owns and operates approximately 5,500 kilometres of transmission and distribution lines.

FortisOntario

The Corporation's wholly owned regulated utility investments in Ontario, collectively FortisOntario, provides integrated electric utility service to approximately 64,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and, as of October 2009, the District of Algoma in Ontario. Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro, which has been leased from the City of Port Colborne under a 10-year lease agreement that expires in April 2012. FortisOntario also owns a 10% interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies serving approximately 38,000 customers.

FortisOntario met a combined peak demand of 273 MW in 2010. FortisOntario owns and operates approximately 3,300 kilometres of transmission and distribution lines.

Market and Sales

Annual electricity sales were 2,328 GWh in 2010 compared to 2,195 GWh in 2009. Revenue was $331 million in 2010 compared to $285 million in 2009.

The following table compares the composition of Other Canadian Electric Utilities' 2010 and 2009 revenue and electricity sales by customer class.

Other Canadian Electric Utilities
Revenue and Electricity Sales by Customer Class

	Revenue [(1)] *(%)*		**GWh Sales** [(1)] *(%)*	
	2010	2009	**2010**	2009
Residential	**42.5**	43.2	**42.9**	43.3
Commercial and industrial	**49.1**	47.3	**56.4**	56.1
Other [(2)]	**8.4**	9.5	**0.7**	0.6
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes financial results of Algoma Power from October 2009*
(2) *Includes revenue from sources other than from the sale of electricity*

Power Supply

Maritime Electric

Maritime Electric purchased 80% of the electricity required to meet its customers' needs from NB Power in 2010. The balance was met through the purchase of wind energy produced on Prince Edward Island. Maritime Electric's on-Island generation facilities are used primarily for peaking, submarine-cable loading issues and emergency purposes.

Maritime Electric generally purchases some of its electricity requirements from Point Lepreau. A major refurbishment of Point Lepreau began in 2008 and is expected to be completed by fall 2012, extending the facility's estimated life an additional 25 years. As permitted by Island Regulatory and Appeals Commission, replacement energy costs incurred during the refurbishment period are being deferred by Maritime Electric and were approximately $47 million to the end of February 2011. The nature and timing of recovery of the deferred costs is subject to further review by a commission to be established by the Government of Prince Edward Island.

On November 12, 2010, Maritime electric signed the Prince Edward Island Energy Accord with the Government of Prince Edward Island. The Prince Edward Island Energy Accord covers the period from March 1, 2011 through February 29, 2016. The Accord will provide rate reductions effective March 1, 2011 and price stability and rate predictability for the next two years.

The combination of reduced energy input costs associated with a new five-year energy purchase agreement with NB Power effective March 1, 2011 and the assumption, by the Government of Prince Edward Island, of certain energy related costs beginning on March 1, 2011 as stipulated in the Prince Edward Island Energy Accord, will contribute to lower costs for consumers effective March 1, 2011. Maritime Electric's exposure with respect to premiums for replacement energy during the refurbishment of Point Lepreau has been capped as of February 2011. For further information, refer to the "Material Regulatory Decisions and Applications – Maritime Electric" section of the MD&A.

The *Renewable Energy Act* (Prince Edward Island) requires Maritime Electric to supply 15% of its annual energy sales from renewable energy sources. The Government of Prince Edward Island intends to install 30 MW of wind turbines on Prince Edward Island by January 1, 2013, with a view to sell the resultant energy to Maritime Electric. Electricity generated from a 10-MW wind farm, scheduled for completion on Prince Edward Island on or about January 1, 2012, will be purchased by the Government of Prince Edward Island and, in turn, sold to Maritime Electric. Approximately 20% of total energy supply was derived from wind-powered generation in 2010.

<u>FortisOntario</u>
The power requirements of FortisOntario's service areas are provided from various sources. Canadian Niagara Power purchases its power requirements for Fort Erie and Port Colborne from IESO. Canadian Niagara Power purchases approximately 88% of energy requirements for Gananoque through monthly energy purchases from Hydro One and the remaining 12% is purchased, through the Hydroelectric Contract Initiative, from five hydroelectric generating plants owned by Fortis Properties. Algoma Power purchases 100% of its energy from IESO.

Under the Standard Supply Code of the Ontario Energy Board, Canadian Niagara Power and Algoma Power are obliged to provide Standard Service Supply to all its customers who do not choose to contract with an electricity retailer. This energy is provided to customers at either regulated or market prices.

Cornwall Electric purchases 100% of its power requirements from Hydro-Québec Energy Marketing under two fixed-term contracts. The first contract, which represents approximately 39% of the power supply, is a 45-MW contract with a 60% capacity factor. The second contract, supplying the remainder of Cornwall Electric's energy requirement, is a 100-MW capacity and energy contract. Both contracts expire in December 2019.

Human Resources

As at December 31, 2010, Maritime Electric had 182 full-time equivalent employees, of which approximately 70% were represented by IBEW, Local 1432. On March 12, 2010, a new collective agreement was reached, which expires December 31, 2013.

As at December 31, 2010, FortisOntario had 199 full-time equivalent employees, of which approximately 59% were represented by CUPE, Local 137, and IBEW, Local 636, in the Niagara Region; IBEW, Local 636, in Gananoque; and Power Workers Union, a CUPE affiliate as CUPE Local 1000, in the Algoma region. The collective agreements governing these employees expire on April 30, 2012; May 31, 2012; July 31, 2012; and December 31, 2012, respectively.

3.3 Regulated Electric Utilities - Caribbean

Regulated Electric Utilities - Caribbean operations are comprised of Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos.

Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize, Central America, serving more than 77,000 customers. The utility owns more than 2,900 kilometres of transmission and distribution lines and met a peak demand of 81 MW in 2010. The Corporation holds an approximate 70% controlling ownership interest in Belize Electricity.

Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 26,000 customers. The Company met a record peak demand of approximately 102 MW in 2010. Caribbean Utilities owns and operates approximately 556 kilometres of transmission and distribution lines. Fortis holds an approximate 59% controlling ownership interest in the utility. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U).

Fortis Turks and Caicos is an integrated electric utility, wholly owned by Fortis, serving approximately 9,000 customers, or 80%, of electricity consumers, in the Turks and Caicos Islands. The utility met a combined record peak demand of approximately 31 MW in 2010. Fortis Turks and Caicos owns and operates approximately 235 kilometres of transmission and distribution lines. The Company is the principal distributor of electricity in the Turks and Caicos Islands pursuant to 50-year licences that expire in 2036 and 2037.

Market and Sales

Annual electricity sales increased to 1,150 GWh in 2010 from 1,140 GWh in 2009. Annual revenue decreased to $335 million in 2010 from $339 million in 2009.

The following table compares the composition of Regulated Electric Utilities - Caribbean's revenue and electricity sales by customer class for the years ended 2010 and 2009.

Regulated Electric Utilities – Caribbean *(1)*
Revenue and Electricity Sales by Customer Class

	Revenue *(%)*		**GWh Sales** *(%)*	
	2010	2009	**2010**	2009
Residential	**48.6**	48.0	**48.3**	48.4
Commercial, industrial and street lighting	**49.4**	50.0	**51.7**	51.6
Other *(2)*	**2.0**	2.0	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos*
(2) *Includes revenue from sources other than from the sale of electricity*

Power Supply

In 2010 approximately 64% of the energy requirements of Regulated Electric Utilities - Caribbean was sourced from in-house diesel-powered and, to a lesser extent, gas-turbine generation.

Belize Electricity meets its energy requirements from multiple sources, which include power purchases from: (i) the Mollejon, Chalillo and Vaca hydroelectric generating facilities owned and operated by BECOL; (ii) the cogeneration facility owned by BELCOGEN; (iii) the heavy fuel oil plant operated by BAL; (iv) the Hydro Maya hydroelectric generating plant owned by Hydro Maya Limited; (v) CFE, the Mexican state-owned power company; and (vi) its own diesel-powered and gas-turbine generation. All major load centers are connected to Belize's national electricity system, which is connected with the Mexican national electricity grid, allowing Belize Electricity to optimize its power supply options. Belize Electricity purchased 98% of its energy requirements from the Mollejon, Chalillo and Vaca hydroelectric generating facilities; BELCOGEN; BAL; Hydro Maya Limited and CFE. The balance was produced by Belize Electricity's installed generating capacity of 34 MW, including a 22-MW gas-turbine generating facility.

In October 2009 the CFE of Mexico cancelled the guaranteed power supply contract for firm energy with Belize Electricity. CFE continues to supply Belize Electricity with power when available. There is sufficient in-country generation to meet energy demand in Belize without supply from CFE.

Caribbean Utilities relies upon in-house diesel-powered generation to produce electricity for Grand Cayman. Grand Cayman has neither hydroelectric potential nor inherent thermal resources and the Company must rely upon diesel fuel imported to Grand Cayman primarily from refineries in the Caribbean and the Gulf of Mexico. The Company has an installed generating capacity of approximately 151 MW.

Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80% of the Company's fuel requirements from this supplier for the operation of Caribbean Utility's diesel-powered generating plant. The initial contract was for three years and terminated in April 2010. Caribbean Utilities continues to operate within the terms of the initial contract. The contract contains an automatic renewal clause for years 2010 through 2012. Should any party choose to terminate the contract within that two-year period, notice must be given a minimum of one year in advance of the desired termination date. As at December 31, 2010, no such termination notice has been given by either party. As such, the contract is effectively renewed for 2011. The quantity of fuel to be purchased under the contract for 2011 is approximately 25 million imperial gallons.

Fortis Turks and Caicos relies upon in-house diesel-powered generation, which has a combined generating capacity of 57 MW, to produce electricity for its customers.

Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

Legal Proceedings

Belize Electricity is involved in a number of legal proceedings relating to the PUC's June 2008 Final Decision. Changes made in electricity legislation by the Government of Belize and the PUC, the PUC's June 2008 Final Decision and the PUC's amendment to the June 2008 Final Decision, which were based on the changed legislation, have been judicially challenged by Belize Electricity in several proceedings. In response to an application from Belize Electricity, the Supreme Court of Belize issued an order in June 2010 prohibiting the PUC from carrying out any rate-setting review proceedings, changing any rates and taking any enforcement or penal steps against Belize Electricity until further order of the Supreme Court.

The evidentiary portion of the trial of Belize Electricity's appeal of the PUC's June 2008 Final Decision was heard in October 2010 with closing arguments completed in December 2010. A court decision on the matter is expected in the first quarter of 2011.

Human Resources

As at December 31, 2010, Regulated Electric Utilities - Caribbean employed 593 full-time equivalent employees. The 191 employees at Caribbean Utilities and 106 employees at Fortis Turks and Caicos are non-unionized. Of the 296 full-time equivalent employees at Belize Electricity, approximately 80% were represented by BEWU. The Company's collective agreement with BEWU was signed in July 2008 with the next review of the agreement scheduled for 2011 and every five years thereafter.

3.4 Non-Regulated - Fortis Generation

The following table summarizes the Corporation's non-regulated generation assets by location.

Fortis Generation Non-Regulated Generation Assets			
Location	**Plants**	**Fuel**	**Capacity (MW)**
Belize (1)	3	hydro	51
Ontario	7	hydro, thermal	13
Central Newfoundland (2)	2	hydro	36
British Columbia (3)	1	hydro	16
Upper New York State	4	hydro	23
Total	**17**		**139**

(1) *Includes the 19-MW Vaca hydroelectric generating facility, which was commissioned in March 2010*
(2) *The two central Newfoundland plants were expropriated by the Government of Newfoundland and Labrador in December 2008. Effective February 12, 2009, the Corporation discontinued the consolidation method of accounting for its investment in central Newfoundland.*
(3) *Once completed, the Waneta Expansion will provide an additional 335 MW of hydroelectric generating capacity in British Columbia.*

The Corporation's non-regulated generation operations consist of its 100% ownership interest in each of BECOL, FortisOntario and FortisUS Energy, as well as non-regulated generation assets owned by Fortis Properties, FortisBC Inc., and by Fortis through its 51% controlling ownership interest in the Waneta Partnership.

Non-regulated generation operations in Belize consist of the 25-MW Mollejon, 7-MW Chalillo and, as of March 2010, 19-MW Vaca hydroelectric generating facilities. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements expiring in 2055 and 2060 and a franchise agreement with the Government of Belize. Under these agreements, the Mollejon hydroelectric generating facility will be transferred to the Government of Belize in 2036, after which it will be leased at an annually increasing rate for a term expiring in 2055.

The US$53 million 19-MW hydroelectric generating facility at Vaca on the Macal River in Belize was commissioned in March 2010. The facility was constructed downstream from the Chalillo and Mollejon hydroelectric generation facilities and is forecast to increase average annual energy production from the Macal River by approximately 80 GWh to 240 GWh.

Non-regulated generation operations of FortisOntario include the operation of a 5-MW gas-powered cogeneration plant in Cornwall. All energy output of this plant is sold to Cornwall Electric. Fortis Properties owns and operates six small hydroelectric generating facilities in eastern Ontario with a combined capacity of 8 MW. The electricity produced from these facilities is sold to the Ontario Power Association, via the Hydroelectric Contract Initiative, under fixed-price contracts.

Fortis Properties also has a non-regulated generation investment in central Newfoundland that is held through the Company's direct 51% interest in the Exploits Partnership. Through the Exploits Partnership, 36 MW of additional capacity was developed and installed at two of Abitibi's hydroelectric generating plants in central Newfoundland. The Exploits Partnership sells its output to Newfoundland Hydro under a 30-year power purchase agreement expiring in 2033. Effective February 12, 2009, the Corporation discontinued the consolidation method of accounting for these operations, necessitated by the actions of the Government of Newfoundland and Labrador related to its expropriation of the assets of the Exploits Partnership (see the "Legal Proceedings" section that follows).

The non-regulated generation operations of FortisBC Inc. include the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia and the 335-MW Waneta Expansion, which is being constructed. The Walden hydroelectric power plant is a non-regulated operation that sells its entire output to BC Hydro under a power purchase agreement expiring in 2013. Effective October 1, 2010, non-regulated generation operations in British Columbia include the Corporation's direct 51% controlling ownership interest in the Waneta Partnership, with CPC/CBT holding the remaining 49% interest. Construction of the Waneta Expansion commenced late in 2010 for completion expected in spring 2015 at an estimated cost of approximately $900 million. SNC-Lavalin was awarded a contract for approximately $590 million to design and build the Waneta Expansion. Approximately $75 million was incurred on this capital project in 2010. For additional information refer to Section 3.2.2 of this AIF.

Through FortisUS Energy, an indirect wholly owned subsidiary, the Corporation owns and operates four hydroelectric generating facilities in Upper New York State with a combined capacity of approximately 23 MW operating under licences from the United States Federal Energy Regulatory Commission. All four hydroelectric generating facilities sell energy at market rates through purchase agreements with Niagara Mohawk Power Corporation.

Market and Sales

Annual energy sales from non-regulated generation assets were 427 GWh in 2010 compared to 583 GWh in 2009. Revenue was $36 million in 2010 compared to $39 million in 2009.

The following table compares the composition of Fortis Generation's 2010 and 2009 revenue and energy sales by location.

Fortis Generation
Revenue and Energy Sales by Location

	Revenue *(%)*		**GWh Sales** *(%)*	
	2010	2009	**2010**	2009
Belize [(1)]	**68.9**	46.1	**60.6**	30.9
Ontario [(2)]	**11.2**	31.0	**11.7**	46.5
Central Newfoundland [(3)]	**3.9**	9.1	**-**	3.3
British Columbia	**5.6**	4.2	**8.4**	4.9
Upper New York State	**10.4**	9.6	**19.3**	14.4
Total	**100.0**	100.0	**100.0**	100.0

(1) *Results reflect contribution from the Vaca hydroelectric generating facility in Belize from March 2010 when the facility was commissioned*
(2) *Results reflect contribution from the Rankine hydroelectric generating facility in Ontario until April 30, 2009, when the Rankine water rights expired at the end of a 100-year term*
(3) *Reflects the discontinuance of the consolidation method of accounting for the financial results of the operations in central Newfoundland, effective February 12, 2009*

Legal Proceedings

Exploits Partnership
In December 2008 the Government of Newfoundland and Labrador expropriated Abitibi's hydroelectric assets and water rights in Newfoundland, including those of the Exploits Partnership. The newsprint mill in Grand Falls-Windsor closed on February 12, 2009, subsequent to which the day-to-day operations of the Exploits Partnership's hydroelectric generating facilities were assumed by Nalcor Energy as an agent for the Government of Newfoundland and Labrador with respect to expropriation matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi in the province. The loss of control over cash flows and operations has required Fortis to cease consolidation of the Exploits Partnership, effective February 12, 2009. Discussions between Fortis Properties and Nalcor Energy with respect to expropriation matters are ongoing.

Human Resources

As at December 31, 2010, Fortis Generation employed 28 full-time equivalent personnel, none of whom participate in a collective agreement.

3.5 Non-Regulated - Fortis Properties

As a wholly owned subsidiary of Fortis, Fortis Properties is the Corporation's vehicle for non-utility diversification and growth. The Company owns and operates 21 hotels, comprised of more than 4,100 rooms, in eight Canadian provinces and approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada.

Revenue was $226 million in 2010 compared to $219 million in 2009. In 2010 Fortis Properties derived approximately 29% of its revenue from real estate operations and 71% of its revenue from hotel operations. Fortis Properties derived approximately 45% of its 2010 operating income from real estate operations and 55% from hotel operations.

Fortis Properties' Real Estate Division is anchored by high-quality tenants under long-term leases. The Real Estate Division ended 2010 with 94.5% occupancy, compared to 96.2% occupancy at the end of 2009. In contrast, the average national occupancy rate was 90.5% at the end of 2010, compared to 90.2% at the end of 2009.

The following table sets out the office and retail properties owned by Fortis Properties.

Fortis Properties
Office and Retail Properties

Property	Location	Type of Property	Gross Lease Area *(square feet 000's)*
Fort William Building	St. John's, NL	Office	188
Cabot Place I	St. John's, NL	Office	135
TD Place	St. John's, NL	Office	94
Fortis Building	St. John's, NL	Office	83
Multiple Office	St. John's, NL	Office and Retail	75
Millbrook Mall	Corner Brook, NL	Retail	118
Fraser Mall	Gander, NL	Retail	99
Marystown Mall	Marystown, NL	Retail	87
Fortis Tower	Corner Brook, NL	Office	69
Viking Mall [(1)]	St. Anthony, NL	Retail	69
Maritime Centre	Halifax, NS	Office and Retail	564
Brunswick Square	Saint John, NB	Office and Retail	512
Kings Place	Fredericton, NB	Office and Retail	292
Blue Cross Centre	Moncton, NB	Office and Retail	324
Delta Regina	Regina, SK	Office	52
Total			**2,761**

[(1)] *Property sold subsequent to December 31, 2010.*

Revenue per available room, at the Hospitality Division of Fortis Properties, had a modest increase to $76.83 in 2010 from $76.55 in 2009. The increase was the result of an increase in the average room rate, partially offset by an overall decrease in hotel occupancy. Average daily room rate increased to $124.17 in 2010, up from $121.98 in 2009, while the average occupancy for 2010 was 61.9% down from the 62.8% achieved in 2009.

The hotels owned and managed by Fortis Properties are summarized as follows.

Fortis Properties Hotels			
Hotels	**Location**	**Number of Guest Rooms**	**Conference Facilities** *(000's square feet)*
Delta St. John's	St. John's, NL	403	21
Holiday Inn St. John's	St. John's, NL	252	11
Sheraton Hotel Newfoundland	St. John's, NL	301	16
Mount Peyton	Grand Falls-Windsor, NL	148	6
Greenwood Inn Corner Brook	Corner Brook, NL	102	5
Four Points by Sheraton Halifax	Halifax, NS	177	12
Delta Sydney	Sydney, NS	152	6
Delta Brunswick	Saint John, NB	254	18
Holiday Inn Kitchener-Waterloo	Kitchener-Waterloo, ON	184	13
Holiday Inn Peterborough	Peterborough, ON	153	7
Holiday Inn Sarnia	Point Edward, ON	217	11
Holiday Inn Cambridge	Cambridge, ON	143	7
Holiday Inn Select Windsor	Windsor, ON	214	14
Greenwood Inn Calgary	Calgary, AB	210	9
Greenwood Inn Edmonton	Edmonton, AB	224	8
Greenwood Inn Winnipeg	Winnipeg, MB	213	10
Ramada Hotel & Suites Lethbridge	Lethbridge, AB	119	5
Holiday Inn Express and Suites Medicine Hat	Medicine Hat, AB	93	1
Best Western Medicine Hat	Medicine Hat, AB	122	-
Holiday Inn Express Kelowna (1)	Kelowna, BC	190	5
Delta Regina	Regina, SK	274	24
Total		**4,145**	**209**

(1) *Includes an additional 70 rooms and approximately 4,500 square feet of meeting space associated with an expansion of the hotel completed in February 2010*

Human Resources

As at December 31, 2010, Fortis Properties employed approximately 2,300 full-time equivalent employees, approximately 50% of whom are represented by unions listed in the following table.

Fortis Properties Unions			
Property	**Union**	**Expiry of Agreement**	**Number of Unionized Employees**
Holiday Inn St. John's	CAW	August 31, 2012	50
Delta St. John's	UFCW	December 31, 2012	264
Greenwood Inn Corner Brook	CAW	March 11, 2013	47
East Side Mario's St. John's	CAW	July 31, 2013	104
Delta Sydney	CAW	September 30, 2011	79
Delta Brunswick & Brunswick Square	USW	June 10, 2013	139
Delta Regina	CEP	November 30, 2010 (1)	183
St. John's Real Estate	IBEW	April 17, 2013	10
Sheraton Hotel Newfoundland	CAW	March 31, 2011	173
Holiday Inn Select Windsor	UFCW	April 30, 2013	52
Mount Peyton	UFCW	December 1, 2011	55
Total			**1,156**

(1) *Collective bargaining commenced January 2011.*

4.0 REGULATION

Each of the Corporation's utilities operates under a cost of service methodology and is regulated by the regulatory body in its respective operating jurisdiction. FortisBC is also subject to performance-based rate-setting extending into 2011, which provides the utility an opportunity to earn in excess of its allowed rate of return on common shareholders' equity. With regulated utilities in eight different jurisdictions, Fortis has significant regulatory expertise.

For information with respect to the nature of regulation and material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities, refer to the "Regulatory Highlights" section of the MD&A and to Note 2 to the Corporation's 2010 Audited Consolidated Financial Statements.

5.0 ENVIRONMENTAL MATTERS

The Corporation and its Canadian subsidiaries are subject to various federal, provincial and municipal laws, regulations and guidelines relating to the protection of the environment including, but not limited to, wildlife, water and land protection, emissions and the proper storage, transportation, recycling and disposal 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 their commencement.

Several key Canadian federal environmental laws and regulations affecting the operations of the Corporation's Canadian subsidiaries include, but are not limited to, the: (i) *Canadian Environmental Assessment Act;* (ii) *Canadian Environmental Protection Act*; (iii) *Transportation of Dangerous Goods Act and Regulations*; (iv) *Hazardous Product Act*; (v) *Canada Wildlife Act*; (vi) *Navigable Waters Protection Act*; (vii) *Canada National Parks Act*; (viii) *Fisheries Act; (ix) Canada Water Act; (x) National Emission Guidelines for Stationary Combustion Turbines; (xi) National Fire Code of Canada; (xii) Pest Control Products Act and Regulations; (xiii) PCB Regulations; (xiv) Canadian Species at Risk Act; and (xv) Ozone Depleting Substances Regulations.*

Environmental risks affecting the Corporation's utility operations include, but are not limited to: (i) hazards associated with the transportation, storage and handling of large volumes of fuel for fuel-powered electricity generating plants, including leeching of the fuel into the ground, nearby watershed areas and open waters; (ii) risk of spills or leaks of petroleum-based products, including PCB-contaminated oil, which are used in the cooling and lubrication of transformers, capacitors and other electrical equipment; (iii) risk of spills or releases into the environment arising from the improper transportation, storage, handling and disposal of other hazardous substances; (iv) GHG emissions, including natural gas and propane leaks and spills and emissions from the combustion of fuel required to generate electricity; (v) risk of fire; (vi) risk of disruption to vegetation; (vii) risk of contamination of soil and water near chemically treated poles; (viii) risk of disruption to fish, animals and their habitat as a result of the creation of artificial water flows and levels associated with hydroelectric water storage and utilization; and (ix) risk of responsibility for remediation of contaminated properties, whether or not such contamination resulted from the Corporation's utility operations.

There are many Canadian provincial and municipal laws, regulations and guidelines that address similar environmental risks as the federal laws, regulations and guidelines, but at a provincial or local level.

In British Columbia, the *Carbon Tax Act, Greenhouse Gas Reduction Targets Act, Clean Energy Act, Greenhouse Gas Reduction (Cap and Trade) Act* and anticipated cap-and-trade regulations specifically affect, or may potentially affect, the operations of the Terasen Gas companies and FortisBC.

Air emissions management is the main environmental concern of the Corporation's regulated gas utilities, primarily due to the uncertainties relating to new and emerging federal and provincial GHG laws, regulations and guidelines. While governmental policy direction is unfolding, it remains to be determined to what extent a GHG air emissions cap will impact these utilities. To help mitigate this uncertainty, the Terasen Gas companies participate in sectoral and industry groups to monitor the development of emerging regulations. In addition, TGI was an active participant in Canada's

Voluntary Climate Change Challenge and Registry and, its successor, the Canadian Greenhouse Gas Challenge Registry. Involvement in stakeholder consultations by the Terasen Gas companies has occurred to ensure the perspective of the Companies is considered such that unnecessary prescriptive reporting requirements do not encumber existing asset integrity management processes that are in place to address operational risks around GHG emissions.

Recent updates to the Government of British Columbia's Energy Plan and GHG reduction targets present risks and opportunities to the Terasen Gas companies and, to a lesser degree, FortisBC. The *Greenhouse Gas Reduction Targets Act* mandates a public sector reduction in GHG emissions of 33% from 2007 levels by 2020. This is coupled with mandates for all new electricity generation to be net carbon neutral. Energy objectives under the *Clean Energy Act* aim to ensure electricity self-sufficiency for British Columbia by 2016. The *Clean Energy Act* also places a new focus on clean demand-side management measures and smart metering technologies. In 2008 the Government of British Columbia amended the *Utilities Commission Act* to require the BCUC to ensure that utilities undertake efficiency and conservation measures in their operations and to consider the Government of British Columbia's energy objectives in specified approval processes.

The energy and GHG emissions policies in British Columbia have created incentives to expand TGI's deployment of renewable energy, such as biogas, and to expand its Energy Efficiency and Conservation Program. Additionally, the introduction of the *Carbon Tax Act* improves the competitive position of natural gas relative to other fossil fuels, as the tax is based on the amount of carbon dioxide equivalent emitted per unit of energy. Natural gas, therefore, has a lower tax rate than oil or coal products.

TGI is one of the first utility companies in Canada to include alternative energy solutions as part of its regulated energy service offerings. TGI recently received approval from the BCUC for a new renewable natural gas program, on a limited basis, for an initial two-year period. An equivalent of 10% of the subscribed customers' natural gas requirements will be sourced from local renewable energy projects feeding gas supply into the TGI network. As part of this program, TGI has received approval to activate two projects that will upgrade raw biogas into biomethane, which will be added to TGI's distribution system. Use of biomethane will reduce emissions from waste decomposition and will help address the Government of British Columbia's climate change goals.

The Waneta Expansion in British Columbia is an example of a clean renewable energy source and is expected to have an annual energy output of 675 GWh when it comes into service.

British Columbia is a participant in the Western Climate Initiative. The participants, consisting of several states and provinces, expect to implement a cap-and-trade program to reduce GHG emissions beginning January 1, 2012. Terasen expects that both TGI and TGVI will be covered under the program. The specific details of which facilities will be covered under the program are dependent on the types of emissions and how individual facilities will be defined under cap-and-trade legislation. The cap-and-trade program will have a declining cap on emissions that all facilities covered under the program must meet, either by reducing emissions internally or by purchasing allowances from other facilities for release over the capped amounts. While allowance costs are based on market prices, it appears likely that the Terasen Gas companies' facilities will be net purchasers of allowances over the near and medium terms.

Terasen is subject to reporting and external verification requirements associated with GHG emissions under Reporting Regulations under the *Greenhouse Gas Reduction (Cap and Trade) Act* that were enacted in November 2009. Internal controls over the GHG emission reporting processes and systems have been validated in accordance with the reporting requirements to ensure the alignment of existing parameters with any additional parameters required as part of the new reporting processes. The Terasen Gas companies have developed capabilities that will manage compliance requirements in the upcoming GHG emissions' trading environment. Terasen will also continue to monitor and assess emerging regulations, in particular the offset and allowance regulations.

The significance of GHG emissions is lower at the Corporation's Canadian regulated electric utilities because their primary business is the distribution of electricity. With respect to FortisAlberta, its operations involve only the distribution of electricity. Additionally, all in-house generating capacity at FortisBC and about 70% at Newfoundland Power and most of the Corporation's non-regulated generating capacity is hydroelectric, a clean energy source. There is no coal-fired generation within any of the Corporation's operations. The Corporation's Canadian regulated electric utilities are indirectly impacted, however, by GHG emissions through the purchase of power generated by suppliers using combustible fuel. Such power suppliers are responsible for compliance with carbon dioxide emissions standards and the cost of compliance with such standards is generally flowed through to end-use consumers.

The *Renewable Energy Act* (Prince Edward Island) and the recent Prince Edward Island Energy Accord directly impacts the long-term energy supply planning process for the province of Prince Edward Island. The Act requires Maritime Electric to supply 15% of its annual energy sales from renewable sources. Under the Prince Edward Island Energy Accord, Maritime Electric and the Government of Prince Edward Island are committed to work collaboratively to increase electricity produced on Prince Edward Island and sold to Maritime Electric from renewable energy sources, principally wind. The Government of Prince Edward Island intends to install 30 MW of wind turbines on Prince Edward Island by January 1, 2013, with a view to sell the resultant energy to Maritime Electric. Electricity generated from a 10-MW wind farm, scheduled for completion on Prince Edward Island on or about January 1, 2012, will be purchased by the Government of Prince Edward Island and, in turn, sold to Maritime Electric.

While there are environmental laws, regulations and guidelines affecting the Corporation's operations in Grand Cayman, Turks and Caicos Islands, and Belize, they are less extensive than the laws, regulations and guidelines in Canada. The United Kingdom's ratification of the United Nations Framework Convention on Climate Change and its Kyoto Protocol, however, were extended to the Cayman Islands and Belize in 2007 and 2003, respectively. This framework aims to reduce GHG emissions produced by certain industries. Specific details on the regulations implementing the protocol have yet to be released by the governments of these countries and, accordingly, Caribbean Utilities and Belize Electricity are currently unable to assess the financial impact of compliance with the framework of the protocol.

All of the energy requirements of Caribbean Utilities and Fortis Turks and Caicos and about 2% of the energy requirements of Belize Electricity are sourced from in-house diesel-powered and, to a lesser extent, gas-turbine generation. Newly installed diesel generators at Caribbean Utilities and Fortis Turks and Caicos have incorporated improvements to generate electricity in a more efficient and environmentally friendly manner. Newly installed generators have also been designed to provide an increased output per gallon consumed than the older generators. The height of exhaust stacks have been increased and improved exhaust systems installed to maximize sound attenuation, and optimize exhaust plume dispersion thereby improving local air quality in accordance with what the utilities believe to be the best industry practice. The use of diesel oil versus heavy fuel oil also results in significantly lower levels of exhaust emissions. The utilities also purchase and store diesel fuel and/or lubricating oil in bulk thereby decreasing the environmental risks associated with fuel and/or oil handling. Investments have been made in containment areas for the bulk storage of diesel fuel which have been designed to prevent the fuel from coming into contact with soil or groundwater. Caribbean Utilities also uses an underground fuel pipeline for the delivery of fuel from suppliers' distribution terminals on the coast of Grand Cayman to the day-tank holding facilities at the Company's generating plant. The pipeline eliminates the need for road transport of fuel along coastline roads.

The key focus of the utilities is to provide reliable cost-effective service with full regard for the safety of employees and the public while operating in an environmentally responsible manner. A focus on safety and the environment is, therefore, an integral and continuing component of the Corporation's operating activities.

Each of the Corporation's utilities has an EMS with the exception of Fortis Turks and Caicos, which is expected to implement an EMS by 2012. Environmental policies form the cornerstone of the EMS and outline the following commitments by each utility and its employees with respect to conducting business in a safe and environmentally responsible manner: (i) meet and comply with all applicable laws, legislation, policies, regulations and accepted standards of environmental protection; (ii) manage activities consistent with industry practice and in support of environmental policies of all levels of government; (iii) identify and manage risks to prevent or reduce adverse consequences from operations, including preventing pollution and conserving natural resources; (iv) regular environmental monitoring and audits of the EMS and striving for continual improvement in environmental performance; (v) set and review environmental objectives, targets and programs regularly; (vi) communicate openly with stakeholders including making available the utility's environmental policy and knowledge on environmental issues to customers, employees, contractors and the general public; (vii) support and participate in community-based projects that focus on the environment; (viii) provide training for employees and those working on behalf of the utility to enable them to fulfill their duties in an environmentally responsible manner; and (ix) work with industry associations, government and other stakeholders to establish standards for the environment appropriate to the utility's business.

Through an EMS, documented procedures are in place to control activities that can affect the environment. Common elements of the utilities' EMSs include: (i) regular inspections of fuel and oil-filled equipment in order to identify and correct for potential spills, and spill response systems to ensure that all spills are addressed, and the associated cleanup is conducted in a prompt and environmentally responsible manner; (ii) GHG emissions management; (iii) procedures for handling, transporting, storing and disposing of hazardous substances, including chemically treated poles, asbestos, lead and mercury, where applicable; (iv) programs to mitigate fire-related incidents; (v) programs for the management and/or elimination of PCBs, where applicable; (vi) vegetation management programs; (vii) training and communicating of environmental policies to employees to ensure work is conducted in an environmentally responsible manner; (viii) review of work practices that affect the environment; (ix) waste management programs; (x) environmental emergency response procedures; (xi) environmental site assessments; and (xii) environmental incident reporting procedures. Additionally, in the case of Newfoundland Power and FortisBC, the EMSs also address water control and dam structure, as well as hydroelectric generating facility operations and the impact of such on fish and the surrounding habitat.

The Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario and Belize Electricity have developed their respective EMSs consistent with the guidelines of ISO 14001, an internationally recognized standard for EMSs. Caribbean Utilities operates an EMS associated with its generation operations, which is ISO 14001 certified, and uses an EMS for its transmission and distribution operations, which is consistent with ISO 14001 guidelines. Fortis Turks and Caicos' EMS, when fully implemented, is also expected to be consistent with ISO 14001 guidelines. As part of their respective EMS, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor performance. External and/or internal audits of the EMSs are performed on a periodic basis. Based on audits completed in 2010, the EMSs continue to be effective, properly implemented and maintained, and materially consistent with ISO 14001 guidelines.

Each of the Corporation's Canadian regulated electric utilities that is a member of the CEA is an active participant in the CEA's Sustainable Electricity Program, which was launched in 2009. Participants in the program commit to continuous improvement of their environmental management and performance including reporting annually on environmental and other performance indicators.

In addition to the EMSs, various energy efficiency programs and initiatives, which help in reducing GHG emissions, are undertaken by the utilities or offered to customers.

Environmental risks associated with the Corporation's non-regulated generation operations are addressed in a similar manner as the Corporation's regulated electric utilities that operate in the same jurisdiction as the non-regulated generation operations, or by environmental practices and procedures followed by Fortis Properties.

The key environmental risks affecting the Corporation's hospitality and real estate operations include, but are not limited to: (i) asbestos and urea-formaldehyde contamination in buildings; (ii) release of ozone-depleting substances from air conditioning and refrigeration equipment; (iii) fuel tank leaks; and (iv) remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. Fortis Properties is committed to meeting the requirements of environmental standards related to its hospitality and real estate operations. In assessing properties being acquired, all must meet environmental standards, including, but not limited to, the appropriate federal, provincial and municipal standards for asbestos, fuel storage, urea-formaldehyde and chlorofluorocarbon-based refrigerants in air conditioning and refrigerating equipment. This process is also applied to existing properties, ensuring environmental compliance by all facilities.

The Corporation has asset-retirement obligations as disclosed in the notes to its 2010 Audited Consolidated Financial Statements. However, liabilities with respect to these asset-retirement obligations have not been recorded in the Corporation's 2010 Audited Consolidated Financial Statements, with the exception of approximately $3 million related to PCBs at FortisBC, as they could not be reasonably estimated or were determined to be immaterial (including asset-retirement obligations associated with asbestos and chemically treated poles) to the Corporation's consolidated results of operations, cash flows or financial position. The utilities have ongoing programs to identify and replace transformers which are at risk of spillage of oil, and PCBs continue to be removed from service and safely disposed of in compliance with applicable laws and regulations.

Costs associated with environmental protection initiatives (including the development, implementation and maintenance of EMSs), compliance with environmental laws, regulations and guidelines, and environmental damage did not materially affect the Corporation's consolidated results of operations, cash flows or financial position during 2010 and, based on current laws, facts and circumstances, are not expected to have a material effect in 2011. Many costs related to carrying out the utilities' EMSs, however, are embedded in the utilities' operating, maintenance and capital programs and are, therefore, not readily identifiable. At the Corporation's regulated utilities, prudently incurred operating and capital costs associated with environmental protection initiatives, compliance with environmental laws, regulations and guidelines, and environmental damage are eligible for recovery in customer rates. Fortis believes that the Corporation and its subsidiaries are materially compliant with environmental laws and regulations applicable to them in the various jurisdictions in which they operate.

Oversight of environmental matters is performed at the subsidiary level with regular reporting of environmental matters to the respective subsidiary's Board of Directors.

For further information on the Corporation's environmental risk factors, refer to the "Business Risk Management - Environmental Risks" section of the MD&A.

6.0 RISK FACTORS

For information with respect to the Corporation's significant business risks, refer to the "Business Risk Management" section of the MD&A.

7.0 GENERAL DESCRIPTION OF SHARE CAPITAL STRUCTURE

The authorized share capital of the Corporation consists of the following:

(a) an unlimited number of Common Shares without nominal or par value;
(b) an unlimited number of First Preference Shares without nominal or par value; and
(c) an unlimited number of Second Preference Shares without nominal or par value.

As at March 4, 2011, the following Common Shares and First Preference Shares were issued and outstanding.

Share Capital	Issued and Outstanding	Votes per Share
Common Shares	175,332,597	One
First Preference Shares, Series C	5,000,000	None
First Preference Shares, Series E	7,993,500	None
First Preference Shares, Series F	5,000,000	None
First Preference Shares, Series G	9,200,000	None
First Preference Shares, Series H	10,000,000	None

The following table summarizes the cash dividends declared per share for each of the Corporation's class of share for the past three years.

	Dividends Declared *(per share)*		
Share Capital	**2008**	**2009** [(1)]	**2010** [(1)]
Common Shares	$1.01	$0.78	$1.41
First Preference Shares, Series C	$1.3625	$1.0219	$1.7031
First Preference Shares, Series E	$1.2250	$0.9188	$1.5313
First Preference Shares, Series F	$1.2250	$0.9188	$1.5313
First Preference Shares, Series G [(2)]	$1.0184	$0.9844	$1.6406
First Preference Shares, Series H [(3)]	-	-	$1.1636

[(1)] *First quarter 2010 dividends were declared in January 2010 resulting in three quarters of dividends declared in 2009 and five quarters of dividends declared in 2010.*
[(2)] *The First Preference Shares, Series G were issued in May and June 2008.*
[(3)] *The First Preference Shares, Series H were issued in January 2010.*

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on Common and Preferred Shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

On December 14, 2010, the Board declared an increase in the quarterly Common Share dividend to $0.29 per share from $0.28 per share, with the first payment occurring on March 1, 2011, to holders of record as of February 11, 2011. Also on December 14, 2010, the Board declared a first quarter 2011 dividend on the First Preference Shares, Series C, E, F, G and H in accordance with the applicable annual prescribed rate and was paid on March 1, 2011 to holders of record as of February 11, 2011.

On March 2, 2011, the Board declared a second quarter 2011 dividend of $0.29 per Common Share and a second quarter 2011 dividend on the First Preference Shares, Series C, E, F, G and H in accordance with the applicable annual prescribed rate. In each case, the second quarter 2011 dividends will be paid on June 1, 2011 to holders of record as of May 13, 2011.

Common Shares

Dividends on Common Shares are declared at the discretion of the Board. Holders of Common Shares are entitled to dividends on a pro rata basis if, as, and when declared by the Board. Subject to the rights of the holders of the First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive dividends in priority to or rateably with the holders of the Common Shares, the Board may declare dividends on the Common Shares to the exclusion of any other class of shares of the Corporation.

On the liquidation, dissolution or winding-up of Fortis, holders of Common Shares are entitled to participate rateably in any distribution of assets of Fortis, subject to the rights of holders of First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or rateably with the holders of the Common Shares.

Holders of the Common Shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Fortis, other than separate meetings of holders of any other class or series of shares, and are entitled to one vote in respect of each Common Share held at such meetings.

First Preference Shares, Series C

The 5,000,000 First Preference Shares, Series C are entitled to fixed cumulative preferential cash dividends at a rate of $1.3625 per share per annum. On or after June 1, 2010, the Corporation may, at its option, redeem for cash the First Preference Shares, Series C, in whole at any time, or in part from time to time, at $25.75 per share if redeemed before June 1, 2011; at $25.50 per share if redeemed on or after June 1, 2011 but before June 1, 2012; at $25.25 per share if redeemed on or after June 1, 2012 but before June 1, 2013; and at $25.00 per share if redeemed on or after June 1, 2013 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. On or after June 1, 2010, the Corporation may, at its option, convert all, or from time to time, any part of the outstanding First Preference Shares, Series C into fully paid and freely tradeable Common Shares of the Corporation. The number of Common Shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per Preference Share, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares. On or after September 1, 2013, each First Preference Share, Series C will be convertible at the option of the holder on the first day of September, December, March and June of each year into freely tradeable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares. If a holder of First Preference Shares, Series C elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference Shares, Series C for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series E

The 7,993,500 First Preference Shares, Series E are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. On or after June 1, 2013, the Corporation may, at its option, redeem all, or from time to time any part of, the outstanding First Preference Shares, Series E by the payment in cash of a sum per redeemed share equal to $25.75 if redeemed during the 12 months commencing June 1, 2013; $25.50 if redeemed during the 12 months commencing June 1, 2014; $25.25 if redeemed during the 12 months commencing June 1, 2015; and $25.00 if redeemed on or after June 1, 2016 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. On or after June 1, 2013, the Corporation may, at its option, convert all, or from time to time any part of the outstanding First Preference Shares, Series E into fully paid and freely tradeable Common Shares of the Corporation.

The number of Common Shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per First Preference Share, Series E, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares at such time. On or after September 1, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first business day of September, December, March and June of each year, into fully paid and freely tradeable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares. If a holder of First Preference Shares, Series E elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference, Shares E for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series F

The 5,000,000 First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. On or after December 1, 2011, the Corporation may, at its option, redeem for cash the First Preference Shares, Series F, in whole at any time or in part from time to time, at $26.00 per share if redeemed before December 1, 2012; at $25.75 per share if redeemed on or after December 1, 2012 but before December 1, 2013; at $25.50 per share if redeemed on or after December 1, 2013 but before December 1, 2014; at $25.25 per share if redeemed on or after December 1, 2014 but before December 1, 2015; and at $25.00 per share if redeemed on or after December 1, 2015 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series G

The 9,200,000 First Preference Shares, Series G are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.3125 per share per annum for each year up to and including August 31, 2013. For each five-year period after that date, the holders of First Preference Shares, Series G are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying the $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13%. On September 1, 2013, and on September 1 every five years thereafter, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series G, in whole at any time, or in part from time to time, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series H

The 10,000,000 First Preference Shares, Series H are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.0625 per share per annum for each year up to but excluding June 1, 2015. For each five-year period after that date, the holders of First Preference Shares, Series H are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 1.45%.

On each Series H Conversion Date, being June 1, 2015, and June 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series H, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series H Conversion Date, the holders of First Preference Shares, Series H, have the option to convert any or all of their First Preference Shares, Series H into an equal number of cumulative redeemable floating rate First Preference Shares, Series I.

The holders of First Preference Shares, Series I will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada Treasury Bills plus 1.45%.

On each Series I Conversion Date, being June 1, 2020, and June 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On any date after June 1, 2015, that is not a Series I Conversion Date, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series I Conversion Date, the holders of First Preference Shares, Series I, have the option to convert any or all of their First Preference Shares, Series I into an equal number of First Preference Shares, Series H.

On any Series H Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series H outstanding, such remaining First Preference Shares, Series H will automatically be converted into an equal number of First Preference Shares, Series I. On any Series I Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series I outstanding, such remaining First Preference Shares, Series I will automatically be converted into an equal number of First Preference Shares, Series H. However, if such automatic conversions would result in less than 1,000,000 Series I First Preference Shares or less than 1,000,000 Series H First Preference Shares outstanding then no automatic conversion would take place.

Convertible Debentures

The Corporation's US$40 million 5.50% Unsecured Subordinated Convertible Debentures, due 2016, are redeemable by the Corporation at par at any time on or after November 7, 2011 and are convertible, at the option of the holder, into the Corporation's Common Shares at US$29.11 per share. The debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the debentures. There is no provision associated with these debentures that restricts the payment of dividends.

Debt Covenant Restrictions on Dividend Distributions

The Trust Indenture pertaining to the Corporation's $200 million Senior Unsecured Debentures contains a covenant which provides that Fortis shall not declare or pay any dividends (other than stock dividends or cumulative preferred dividends on preferred shares not issued as stock dividends) or make any other distribution on its shares or redeem any of its shares or prepay Subordinated Debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

The Corporation has a $600 million unsecured committed revolving credit facility, maturing in May 2012, that can be used for general corporate purposes, including acquisitions. The credit facility contains a covenant which provides that Fortis shall not declare or pay any dividends or make any other restricted payments if, immediately thereafter, consolidated debt to consolidated capitalization ratio would exceed 70% at any time.

As at December 31, 2010 and 2009, the Corporation was in compliance with its debt covenant restrictions pertaining to dividend distributions, as described above.

8.0 CREDIT RATINGS

Securities issued by Fortis and its currently rated utilities are rated by one or more credit rating agencies, namely, DBRS, S&P and/or Moody's. The ratings assigned to securities issued by Fortis and its currently rated utilities are reviewed by the agencies on an ongoing basis. Credit ratings and stability ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are not recommendations to buy, sell or hold securities. Ratings may be subject to revision or withdrawal at any time by the rating organization. The following table summarizes the Corporation's credit ratings as at March 7, 2011.

Fortis Credit Ratings			
Company	**DBRS**	**S&P**	**Moody's**
Fortis	A (low), stable (unsecured debt)	A-, stable (unsecured debt)	N/A
Terasen	BBB (high), stable (unsecured debt)	N/A	Baa2, stable (unsecured debt)
TGI	A, stable (secured & unsecured debt)	N/A	A3, stable (unsecured debt)
TGVI	N/A	N/A	A3, stable (unsecured debt)
FortisAlberta	A (low), stable (senior unsecured debt)	A-, stable (senior unsecured debt)	Baa1, stable (senior unsecured debt)
FortisBC	A (low), stable (secured & unsecured debt)	N/A	Baa1, stable (unsecured debt)
Newfoundland Power	A, stable (first mortgage bonds)	N/A	A2, stable (first mortgage bonds)
Maritime Electric	N/A	A-, stable (senior secured debt)	N/A
Caribbean Utilities	A (low), stable (senior unsecured debt)	A, negative (senior unsecured debt)	N/A

DBRS rates debt instruments by rating categories ranging from AAA to D, which represents the range from highest to lowest quality of such securities. DBRS states that: (i) 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; (ii) its 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; and (iii) every rating is based on quantitative and qualitative considerations that are relevant for the borrowing entity. According to DBRS, a rating of A by DBRS is in the middle of three subcategories within the third highest of nine major categories. Such rating is assigned to debt instruments considered to be of satisfactory credit quality and for which protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. Entities in the BBB category are considered to have long-term debt 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. The assignment of a (high) or (low) modifier within each rating category indicates relative standing within such category.

S&P long-term debt ratings are on a ratings scale that ranges from AAA to C, which represents the range from highest to lowest quality of such securities. S&P uses '+' or '-' designations to indicate the relative standing of securities within a particular rating category. S&P states that its credit ratings are current opinions of the financial security characteristics with respect to the ability to pay under contracts in accordance with their terms. This opinion is not specific to any particular contract, nor does it address the suitability of a particular contract for a specific purpose or purchaser. An issuer rated A is regarded as having financial security characteristics to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than those in higher-rated categories.

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 states that its long-term debt ratings are opinions of relative risk of fixed-income obligations with an original maturity of one year or more and that 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 and such a debt rating is assigned to debt instruments considered to be of medium-grade quality. Debt instruments rated Baa are subject to moderate credit risk and may possess certain speculative characteristics. Debt instruments rated A are considered upper-medium grade and are subject to low credit risk.

9.0 MARKET FOR SECURITIES

The Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; and First Preference Shares, Series H of Fortis are listed on the Toronto Stock Exchange under the symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F, FTS.PR.G and FTS.PR.H, respectively.

The following table sets forth the reported high and low trading prices and trading volumes for the Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; and First Preference Shares, Series H on a monthly basis for the year ended December 31, 2010.

Fortis
2010 Trading Prices and Volumes

	Common Shares			First Preference Shares, Series C		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
Jan	28.92	27.65	7,598,632	26.65	26.30	250,206
Feb	28.49	26.45	9,647,325	26.73	26.11	102,326
Mar	29.32	27.45	12,182,466	26.45	26.02	31,318
Apr	29.24	27.11	7,711,897	26.52	25.70	21,817
May	28.31	21.60	12,077,181	26.00	25.52	106,463
Jun	28.35	26.51	10,261,047	26.36	25.75	19,692
Jul	29.37	26.83	7,559,548	27.00	26.20	19,206
Aug	29.51	28.25	12,267,132	26.60	26.26	6,191
Sep	32.39	29.45	10,444,191	26.67	26.20	82,791
Oct	33.34	31.22	7,443,166	27.10	26.20	82,316
Nov	33.63	30.50	14,538,415	27.90	26.00	55,307
Dec	34.54	32.27	9,124,490	26.27	25.50	72,697
	First Preference Shares, Series E			**First Preference Shares, Series F**		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
Jan	27.36	26.20	156,593	22.26	21.50	70,432
Feb	27.93	26.75	48,528	22.14	21.00	50,686
Mar	28.51	27.45	79,628	21.46	20.55	93,383
Apr	27.81	26.75	38,661	20.50	19.80	148,011
May	26.95	25.65	77,005	20.26	19.45	78,608
Jun	26.70	26.01	35,587	21.20	20.01	43,550
Jul	26.85	26.25	233,990	21.90	20.95	47,155
Aug	27.83	26.15	66,419	21.92	21.54	54,955
Sep	27.99	26.88	48,182	22.84	21.91	305,678
Oct	27.40	26.82	176,316	23.49	22.60	49,843
Nov	27.69	26.90	46,446	23.91	23.01	55,907
Dec	27.31	26.75	387,978	23.20	22.55	105,720
	First Preference Shares, Series G			**First Preference Shares, Series H**		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
Jan	26.75	25.56	113,073	25.20	24.95	909,840
Feb	26.75	25.90	68,982	25.55	25.00	505,423
Mar	26.75	25.54	86,772	25.60	25.07	218,402
Apr	26.31	25.40	88,767	25.45	24.60	142,103
May	26.15	25.55	72,715	25.00	24.15	128,250
Jun	26.24	25.61	67,343	25.10	24.40	157,834
Jul	26.49	25.75	398,816	25.25	24.80	83,340
Aug	26.74	25.70	100,414	25.51	24.71	140,492
Sep	26.72	25.91	92,166	26.00	25.15	141,417
Oct	26.70	26.00	105,727	26.00	25.45	152,170
Nov	27.25	25.99	78,194	26.22	25.39	433,361
Dec	26.74	25.30	103,646	25.61	25.25	510,574

10.0 DIRECTORS AND OFFICERS

The Board adopted a new director tenure policy in September 2010 and it is to be reviewed on a periodic basis. The tenure policy provides that Directors of the Corporation are to be elected for a term of one year and, except in appropriate circumstances determined by the Board, be eligible for re-election until the Annual Meeting of Shareholders next following the date on which they achieve age 70 or the 12th anniversary of their initial election to the Board. The policy does not apply to Mr. Marshall whose service on the Board is related to his tenure as CEO. The following chart sets out the name and municipality of residence of each of the Directors of Fortis and indicates their principal occupations within five preceding years.

Fortis Directors	
Name	**Principal Occupations Within Five Preceding Years**
PETER E. CASE *(1)* Kingston, Ontario	Mr. Case, 56, a Corporate Director, retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. During his 17-year career as senior investment analyst with CIBC World Markets and BMO Nesbitt Burns and its predecessors, Mr. Case's coverage of Canadian and selected U.S. pipeline and energy utilities was consistently rated among the top rankings. He was awarded a Bachelor of Arts and a Master of Business Administration from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto. Mr. Case was first elected to the Board in May 2005. Mr. Case was a Director of FortisOntario from 2003 to 2010 and served as Chair of the FortisOntario Board from 2009 to 2010. He does not serve as a director of any other reporting issuer.
FRANK J. CROTHERS Nassau, Bahamas	Mr. Crothers, 66, is Chairman and Chief Executive Officer of Island Corporate Holdings Limited, Nassau, Bahamas. For more than 35 years, he has served on many public and private sector boards. For more than a decade he was on the Board of Harvard University Graduate School of Education and also served a three-year term as Chairman of CARILEC, the Caribbean Association of Electrical Utilities. Mr. Crothers is the past President of P.P.C. Limited, which was acquired by the Corporation in August 2006. He serves as Vice Chair of the Board of Caribbean Utilities. Mr. Crothers was first elected to the Fortis Board in May 2007. He was previously a director of Belize Electricity from 2007 to 2010. Mr. Crothers is also a director of reporting issuers Templeton Mutual Funds and Talon Metals Corp.
IDA J. GOODREAU *(3)* Vancouver, British Columbia	Ms. Goodreau, 59, is an Adjunct Professor at Sauder School of Business and Director of Strategy, Center for Healthcare Management, University of British Columbia. She is the past President and Chief Executive Officer of LifeLabs. Prior to joining Lifelabs in March 2009, she was President and Chief Executive Officer of the Vancouver Coastal Health Authority since 2002. Ms. Goodreau has held senior leadership roles in several Canadian and international pulp and paper and natural gas companies prior to entering the health care field. She was awarded a Master of Business Administration and a Bachelor of Commerce, Honors, degree from the University of Windsor and a Bachelor of Arts, (English and Economics) from the University of Western Ontario. Ms. Goodreau was first elected to the Board in May 2009. She has served on numerous private and public sector boards and has been a director of Terasen and FortisBC since 2007 and 2010, respectively. Ms. Goodreau does not serve as a director of any other reporting issuer.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
DOUGLAS J. HAUGHEY *(1)* Calgary, Alberta	Mr. Haughey, 54, is President and Chief Executive Officer of Provident Energy Ltd. and also serves on the Company's Board of Directors. He is past President and Chief Executive Officer of Spectra Energy Income Fund and past President of Spectra Energy Transmission West, Spectra's Canadian natural gas and liquids mainstream business. Mr. Haughey also led Spectra's strategic development and mergers and acquisitions teams based in Houston, Texas. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with a Master of Business Administration. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors. He was first elected to the Board in May 2009. Mr. Haughey became a director of FortisAlberta in 2010. He does not serve as a director of any other reporting issuer.
H. STANLEY MARSHALL Paradise, Newfoundland and Labrador	Mr. Marshall, 60, is President and Chief Executive Officer of the Corporation. He joined Newfoundland Power in 1979 and was appointed President and Chief Executive Officer of Fortis in 1996. Mr. Marshall graduated from the University of Waterloo with a Bachelor of Applied Science (Chem. Eng.) and Dalhousie University with a Bachelor of Laws. He is a member of the Law Society of Newfoundland and Labrador and a Registered Professional Engineer in the Province of Newfoundland and Labrador. Mr. Marshall was first elected to the Board in October 1995. He serves on the boards of all Fortis utilities in western Canada and the Caribbean and the Board of Fortis Properties. He is also a director of Toromont Industries Ltd.
JOHN S. McCALLUM *(1)(2)* Winnipeg, Manitoba	Mr. McCallum, 66, has been a Professor of Finance at the University of Manitoba since July 1973. He served as Chairman of Manitoba Hydro from 1991 to 2000 and as Policy Advisor to the Federal Minister of Finance from 1984 to 1991. Mr. McCallum graduated from the University of Montreal with a Bachelor of Arts (Economics) and a Bachelor of Science (Mathematics). He was awarded a Master of Business Administration from Queen's University and a PhD in Finance from the University of Toronto. Mr. McCallum was first elected to the Board in July 2001 and was appointed Chair of the Governance and Nominating Committee of the Corporation in May 2005. He was previously a director of FortisBC and FortisAlberta from 2004 to 2010 and from 2005 to 2010, respectively. Mr. McCallum also serves as a director of IGM Financial Inc., Toromont Industries Ltd. and Wawanesa.
HARRY McWATTERS *(2)* Summerland, British Columbia	Mr. McWatters, 65, is the founder and past President of Sumac Ridge Estate Wine Group, a leader in the British Columbia wine industry. He is President of Vintage Consulting Group Inc., Harry McWatters Inc., Okanagan Wine Academy and Black Sage Vineyards Ltd., all of which are engaged in various aspects of the British Columbia wine industry. Mr. McWatters was first elected to the Board in May 2007. He was elected to the Board of FortisBC in September 2005 and appointed as Chair of that Company's Board in 2006. Mr. McWatters became a director of Terasen in November 2007 and does not serve as a director of any other reporting issuer.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
RONALD D. MUNKLEY *(2)* Mississauga, Ontario	Mr. Munkley, 64, a Corporate Director, retired in April 2009 as Vice Chairman and Head of the Power and Utility Business of CIBC World Markets. Mr. Munkley had acted as an advisor on most Canadian utility transactions since joining CIBC World Markets in 1998. Prior to that, he was employed at Enbridge Consumers Gas for 27 years, culminating as Chairman, President and Chief Executive Officer. Mr. Munkley led Enbridge Consumers Gas through deregulation and restructuring in the 1990s. He graduated from Queen's University with a Bachelor of Science, Honors (Engineering). Mr. Munkley is a professional engineer and has completed the Executive and Senior Executive Programs of the University of Western Ontario and the Partners, Directors and Senior Officers Certificate of the Canadian Securities Institute. He was first elected to the Board in May 2009. Mr. Munkley does not serve as a director of any other reporting issuer.
DAVID G. NORRIS *(1)(3)(4)* St. John's, Newfoundland and Labrador	Mr. Norris, 63, a Corporate Director, has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited. Previously, he held Deputy Minister positions with the Department of Finance and Treasury Board, Government of Newfoundland and Labrador. Mr. Norris graduated with a Bachelor of Commerce from Memorial University of Newfoundland and a Master of Business Administration from McMaster University. He was first elected to the Board in May 2005 and was appointed Chair of the Board in December 2010. He has served as Chair of the Audit Committee of the Board since May 2006. Mr. Norris was a director of Newfoundland Power from 2003 to 2010 and served as Chair of Newfoundland Power's Board from 2006 to 2010. He served as a director of Fortis Properties from 2006 to 2010. Mr. Norris does not serve as a director of any other reporting issuer.
MICHAEL A. PAVEY *(3)* Moncton, New Brunswick	Mr. Pavey, 63, a Corporate Director, retired as Executive Vice-President and Chief Financial Officer of Major Drilling Group International Inc. in September 2006. Prior to joining Major Drilling Group International Inc. in 1999, he held senior executive positions with a major integrated electric utility in western Canada. Mr. Pavey graduated from the University of Waterloo with a Bachelor of Applied Science (Mechanical Engineering) and from McGill University with a Master of Business Administration. He retired from the Board of Maritime Electric in February 2007 after a six-year term, which included three years' service as Chair of that Company's Audit and Environment Committee. Mr. Pavey was first elected to the Board in May 2004. He does not serve as a director of any other reporting issuer.
ROY P. RIDEOUT *(2)(3)* Halifax, Nova Scotia	Mr. Rideout, 63, a Corporate Director, retired as Chairman and Chief Executive Officer of Clarke Inc. in October 2002. Prior to 1998, he served as President of Newfoundland Capital Corporation Limited and held senior executive positions in the Canadian airline industry. Mr. Rideout graduated with a Bachelor of Commerce from Memorial University of Newfoundland and obtained designation as a Chartered Accountant. Mr. Rideout was first elected to the Board in March 2001. He is the Chair of the Human Resources Committee of the Board and has held that position since May 2003. Mr. Rideout also serves as a director of NAV CANADA.

(1) *Serves on the Audit Committee*
(2) *Serves on the Governance and Nominating Committee*
(3) *Serves on the Human Resources Committee*
(4) *Appointed Chair of the Board after the sudden passing of the previous Chair, Geoffrey F. Hyland in November 2010*

The following table sets out the name and municipality of residence of each of the officers of Fortis and indicates the office held.

Fortis Officers	
Name and Municipality of Residence	**Office Held**
H. Stanley Marshall Paradise, Newfoundland and Labrador	President and Chief Executive Officer *(1)*
Barry V. Perry Mount Pearl, Newfoundland and Labrador	Vice President, Finance and Chief Financial Officer *(2)*
Ronald W. McCabe St. John's, Newfoundland and Labrador	Vice President, General Counsel and Corporate Secretary *(3)*
Donna G. Hynes St. John's, Newfoundland and Labrador	Assistant Secretary *(4)*

(1) *Mr. Marshall was appointed President and Chief Operating Officer, effective October 1, 1995. Effective May 1, 1996, Mr. Marshall became Chief Executive Officer.*
(2) *Mr. Perry was appointed Vice President, Finance and Chief Financial Officer, effective January 1, 2004. Prior to that time, Mr. Perry was Vice President, Finance and Chief Financial Officer of Newfoundland Power.*
(3) *Mr. McCabe was appointed General Counsel and Corporate Secretary, effective January 1, 1997. Effective May 6, 2008, Mr. McCabe became Vice President, General Counsel and Corporate Secretary.*
(4) *Ms. Hynes was appointed Assistant Secretary, effective December 8, 1999. She joined Fortis as Manager, Investor and Public Relations in October 1999 and, prior to that time, was employed by Newfoundland Power.*

As at December 31, 2010, the directors and officers of Fortis, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 762,854 Common Shares, representing 0.4% of the issued and outstanding Common Shares of Fortis. The Common Shares are the only voting securities of the Corporation.

11.0 AUDIT COMMITTEE

11.1 Education and Experience

The education and experience of each Audit Committee Member that is relevant to such Member's responsibilities as a Member of the Audit Committee are set out below. As at December 31, 2010, the Audit Committee was composed of the following persons.

Fortis Audit Committee	
Name	**Relevant Education and Experience**
PETER E. CASE Kingston, Ontario	Mr. Case retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. He was awarded a Bachelor of Arts and a Master of Business Administration from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto.
DOUGLAS J. HAUGHEY Calgary, Alberta	Mr. Haughey is President and Chief Executive Officer of Provident Energy Ltd. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with a Master of Business Administration. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors.
JOHN S. McCALLUM Winnipeg, Manitoba	Mr. McCallum is a Professor of Finance at the University of Manitoba. He graduated from the University of Montreal with a Bachelor of Arts (Economics) and a Bachelor of Science (Mathematics). Mr. McCallum was awarded a Master of Business Administration from Queen's University and a PhD in Finance from the University of Toronto.
DAVID G. NORRIS *(Chair)* St. John's, Newfoundland and Labrador	Mr. Norris has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited. He graduated with a Bachelor of Commerce from Memorial University of Newfoundland and a Master of Business Administration from McMaster University.

The Board has determined that each of the Audit Committee Members is independent and financially literate. Independent means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110 - *Audit Committees*. Financially literate means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be raised by the Corporation's consolidated financial statements.

11.2 Audit Committee Mandate

The text of the Corporation's Audit Committee Mandate is detailed below.

A. Objective

The Committee shall provide assistance to the Board by overseeing the external audit of the Corporation's annual financial statements and the accounting and financial reporting and disclosure processes and policies of the Corporation.

B. Definitions

In this mandate:

"AIF" means the Annual Information Form filed by the Corporation;

"Committee" means the Audit Committee appointed by the Board pursuant to this mandate;

"Board" means the board of directors of the Corporation;

"CICA" means the Canadian Institute of Chartered Accountants or any successor body;

"Corporation" means Fortis Inc.;

"**Director"** means a member of the Board;

"Financially Literate" means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be present in the Corporation's financial statements;

"External Auditor" means the firm of chartered accountants, registered with the Canadian Public Accountability Board or its successor, and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

"Independent" means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110;

"Internal Auditor" means the person employed or engaged by the Corporation to perform the internal audit function of the Corporation;

"Management" means the senior officers of the Corporation;

"MD&A" means the Corporation's management discussion and analysis prepared in accordance with National Instrument 51-102F1 in respect of the Corporation's annual and interim financial statements; and

"Member" means a Director appointed to the Committee.

C. Composition and Meetings

1. The Committee shall be appointed annually by the Board and shall be comprised of three (3) or more Directors, each of whom is Independent and Financially Literate and none of whom is a member of Management or an employee of the Corporation or of any affiliate of the Corporation.

2. The Board shall appoint a Chair of the Committee on the recommendation of the Corporation's Governance and Nominating Committee, or such other committee as the Board may authorize.

3. The Committee shall meet at least four (4) times each year and shall meet at such other times during the year as it deems appropriate. Meetings of the Committee shall be held at the call (i) of the Chair of the Committee, or (ii) of any two (2) Members, or (iii) of the External Auditor.

4. The President and Chief Executive Officer, the Vice President, Finance and Chief Financial Officer, the External Auditor and the Internal Auditor, shall receive notice of, and (unless otherwise determined by the Chair of the Committee) shall attend all meetings of the Committee.

5. A quorum at any meeting of the Committee shall be three (3) Members.

6. The Chair of the Committee shall act as chair of all meetings of the Committee at which the Chair is present. In the absence of the Chair from any meeting of the Committee, the Members present at the meeting shall appoint one of their Members to act as Chair of the meeting.

7. Unless otherwise determined by the Chair of the Committee, the Secretary of the Corporation shall act as secretary of all meetings of the Committee.

D. Oversight of the External Audit and the Accounting and Financial Reporting and Disclosure Processes and Policies

The primary purpose of the Committee is oversight of the Corporation's external audit and the accounting and financial reporting and disclosure processes and policies on behalf of the Board. Management of the Corporation is responsible for the selection, implementation and maintenance of appropriate accounting and financial reporting principles and policies and internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations. Management is responsible for the preparation and integrity of the financial statements of the Corporation.

1. Oversight of the External Audit

The oversight of the external audit pertains to the audit of the Corporation's annual financial statements.

1.1. The Committee is responsible for the evaluation and recommendation of the External Auditor to be proposed by the Board for appointment by the shareholders.

1.2. In advance of each audit, the Committee shall review the External Auditor's audit plan including the general approach, scope and areas subject to risk of material misstatement.

1.3. The Committee is responsible for approving the terms of engagement and fees of the External Auditor.

1.4. The Committee shall review and discuss the Corporation's annual audited financial statements, together with the External Auditor's report thereon, and MD&A with Management and the External Auditor to gain reasonable assurance as to the accuracy, consistency and completeness thereof. The Committee shall meet privately with the External Auditor. The Committee shall oversee the work of the External Auditor and resolve any disagreements between Management and the External Auditor.

1.5 The Committee shall use reasonable efforts, including discussion with the External Auditor, to satisfy itself as to the External Auditor's independence as defined in Canadian Auditing Standard – 260.

2. Oversight of the Accounting and Financial Reporting and Disclosure Processes

2.1. The Committee shall recommend the annual audited financial statements together with the MD&A for approval by the Board.

2.2. The Committee shall review the interim unaudited financial statements with the External Auditor and Management, together with the External Auditor's review engagement report thereon.

2.3. The Committee shall review and approve publication of the interim unaudited financial statements together with notes thereto, the interim MD&A and earnings media release on behalf of the Board.

2.4. The Committee shall review and recommend approval by the Board of the Corporation's AIF, Management Information Circular, any prospectus and other financial information or disclosure documents to be issued by the Corporation prior to their public release.

2.5. The Committee shall use reasonable efforts to satisfy itself as to the integrity of the Corporation's financial information systems, internal control over financial reporting and the competence of the Corporation's accounting personnel and senior financial management responsible for accounting and financial reporting.

2.6. The Committee shall be responsible for the oversight of the Internal Auditor.

2.7. The Committee shall monitor and report on the development of the Enterprise Risk Management Program.

3. Oversight of the Audit Committee Mandate and Policies

On a periodic basis, the Committee shall review and report to the Board on the Audit Committee Mandate as well as on the following policies:

3.1. Reporting Allegations of Suspected Improper Conduct and Wrongdoing Policy;

3.2. Derivative Financial Instruments and Hedging Policy;

3.3. Pre-Approval of Audit and Non-Audit Services Policy;

3.4. Hiring of Employees from Independent Auditing Firms Policy;

3.5. The Internal Audit Role and Function Policy; and

3.6 any other policies that may be established, from time to time, relating to accounting and financial reporting and disclosure processes; oversight of the external audit of the Corporation's financial statements; and oversight of the internal audit function.

E. Reporting

The Chair of the Committee, or another designated Member, shall report to the Board at each regular meeting on those matters which were dealt with by the Committee since the last regular meeting of the Board.

F. Other

1. The Committee shall perform such other functions as may, from time to time, be assigned to the Committee by the Board.

2. The Committee may approve, in circumstances that it considers appropriate, the engagement by the Committee or any Director of outside advisors or persons having special expertise at the expense of the Corporation.

11.3 Pre-Approval Policies and Procedures

The Audit Committee has established a policy which requires pre-approval of all audit and non-audit services provided to the Corporation and its subsidiaries by the Corporation's External Auditor. The Pre-Approval of Audit and Non-Audit Services Policy describes the services which may be contracted from the External Auditor and the limitations and authorization procedures related thereto. This policy defines services such as bookkeeping, valuations, internal audit and management functions which may not be contracted from the External Auditor and establishes an annual limit for permissible non-audit services not greater than the total fee for audit services. Audit Committee pre-approval is required for all audit and non-audit services.

11.4 External Auditor Service Fees

Fees incurred by the Corporation for work performed by Ernst & Young LLP, the Corporation's External Auditors, during each of the last two fiscal years for audit, audit-related and tax services were as follows:

Fortis External Auditor Service Fees *($ thousands)*		
Ernst & Young LLP	**2010**	2009
Audit Fees	**2,703**	2,280
Audit-Related Fees	**607**	855
Tax Fees	**202**	354
Total	**3,512**	3,489

Audit fees in 2010 increased, as compared to 2009, primarily due to 2009 audit work billed in 2010 related to Algoma Power which was acquired in October 2009, combined with auditor review procedures performed in 2010 in preparation for the Corporation's previously expected adoption of IFRS, effective January 1, 2011. Audit-related fees decreased in 2010, as compared to 2009, mainly due to less audit-related work required in 2010 associated with the filing of prospectuses for preference equity and debt financings at the corporate and subsidiary levels, respectively. Tax fees were higher in 2009, as compared to 2010, due to tax work performed in 2009 associated with the corporate reorganization of FortisUS Energy and work performed in relation to the adoption of amended CICA Handbook Section 3465, *Income Taxes* by the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power.

12.0 TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares and First Preference Shares of Fortis is Computershare Trust Company of Canada in Halifax, Montréal and Toronto.

Computershare Trust Company of Canada
9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.computershare.com/fortisinc

13.0 AUDITORS

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants, The Fortis Building, 7th Floor, 139 Water Street, St. John’s, NL, A1C 1B2. The financial statements of the Corporation for the fiscal year ended December 31, 2010 have been audited by Ernst & Young LLP. Ernst & Young LLP report that they are independent of the Corporation in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Newfoundland.

14.0 ADDITIONAL INFORMATION

Reference is made to the MD&A and 2010 Audited Consolidated Financial Statements on pages 8 through 69 and pages 70 through 121, respectively, of the 2010 Fortis Inc. Annual Report to Shareholders, which pages are incorporated herein by reference. Additional information relating to the Corporation can be found on SEDAR at www.sedar.com.

Further additional information, including officers’ and directors’ remuneration and indebtedness, principal holders of the securities of Fortis, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in the Management Information Circular of Fortis dated March 21, 2011 for the May 6, 2011 Annual Meeting of Shareholders. Additional financial information is also provided in the 2010 Audited Consolidated Financial Statements and the MD&A.

Requests for additional copies of the above-mentioned documents, as well as the 2010 Annual Information Form, should be directed to the Corporate Secretary, Fortis, P.O. Box 8837, St. John’s, NL, A1B 3T2 (telephone: 709.737.2800). In addition, such documentation and additional information relating to the Corporation is contained on the Corporation’s website at www.fortisinc.com.

FORTIS INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2011

March 15, 2012

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2011

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DEFINITIONS OF CERTAIN TERMS

Certain terms used in this Annual Information Form are defined below:

"2011 Annual Information Form" means this Fortis Inc. Annual Information Form in respect of the year ended December 31, 2011;

"2011 Audited Consolidated Financial Statements" means the audited comparative consolidated financial statements of Fortis Inc. as at and for the year ended December 31, 2011 and related notes thereto;

"Abitibi" means AbitibiBowater Inc.;

"AESO" means Alberta Electric System Operator;

"Algoma Power" means Algoma Power Inc.;

"AUC" means Alberta Utilities Commission;

"BC Hydro" means BC Hydro and Power Authority;

"BCUC" means British Columbia Utilities Commission;

"BECOL" means Belize Electric Company Limited;

"Belize Electricity" means Belize Electricity Limited;

"BEPC" means Brilliant Expansion Power Corporation;

"Board" means Board of Directors of Fortis Inc.;

"BPC" means Brilliant Power Corporation;

"Canadian GAAP" means Canadian generally accepted accounting principles;

"Canadian Niagara Power" means Canadian Niagara Power Inc.;

"Caribbean Utilities" means Caribbean Utilities Company, Ltd.;

"CAW" means Canadian Auto Workers-Retail/Wholesale;

"CEA" means Canadian Electricity Association;

"CEP" means Communications, Energy and Paperworkers Union of Canada;

"CH Energy Group" means CH Energy Group, Inc.;

"COPE" means Canadian Office and Professional Employees Union;

"Cornwall Electric" means Cornwall Street Railway, Light and Power Company, Limited;

"Corporation" means Fortis Inc.;

"CPA" means Canal Plant Agreement;

"CPC/CBT" means Columbia Power Corporation and Columbia Basin Trust;

"CUPE" means Canadian Union of Public Employees;

"DBRS" means DBRS Limited;

"EMS" means environmental management system;

"Exchange Act" means the *U.S. Securities Exchange Act of 1934*, as amended;

"Exploits Partnership" means Exploits River Hydro Partnership between Abitibi and Fortis Properties Corporation;

"External Auditor" means the firm of chartered accountants registered with the Canadian Public Accountability Board or its successor and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

"FEI" means FortisBC Energy Inc. (formerly Terasen Gas Inc.);

"FEVI" means FortisBC Energy (Vancouver Island) Inc. (formerly Terasen Gas (Vancouver Island) Inc.);

"FEWI" means FortisBC Energy (Whistler) Inc. (formerly Terasen Gas (Whistler) Inc.);

"FHI" means FortisBC Holdings Inc. (formerly Terasen Inc.), the parent company of FEI, FEVI and FEWI;

"Fortis" means Fortis Inc.;

"FortisAlberta" means FortisAlberta Inc.;

"FortisAlberta Holdings" means FortisAlberta Holdings Inc.;

"FortisBC Electric" means, collectively, the operations of FortisBC Inc. and its parent company, Fortis Pacific Holdings Inc., but excluding its wholly owned partnership, Walden Power Partnership;

"FortisBC Energy companies" means, collectively, the operations of FEI, FEVI and FEWI;

"FortisOntario" means, collectively, the operations of Canadian Niagara Power, Cornwall Electric and Algoma Power. Canadian Niagara Power's accounts include the operation of the electricity distribution business of Port Colborne Hydro Inc.;

"Fortis Pacific Holdings" means Fortis Pacific Holdings Inc.;

"Fortis Properties" means Fortis Properties Corporation;

"Fortis Turks and Caicos" means, collectively, FortisTCI Limited (formerly P.P.C. Limited) and Atlantic Equipment & Power (Turks and Caicos) Ltd.;

"FortisUS Energy" means FortisUS Energy Corporation;

"FortisWest" means FortisWest Inc.;

"GHG" means greenhouse gas;

"GOB" means Government of Belize;

"GSMIP" means Gas Supply Mitigation Incentive Plan;

"GWh" means gigawatt hour(s);

"Hydro One" means Hydro One Networks Inc.;

"IASB" means International Accounting Standards Board;

"IBEW" means International Brotherhood of Electrical Workers;

"IESO" means Independent Electricity System Operator of Ontario;

"IFRS" means International Financial Reporting Standards;

"ISO" means International Organization for Standardization;

"Management" means, collectively, senior officers of the Corporation;

"Maritime Electric" means Maritime Electric Company, Limited;

"MD&A" means the Corporation's Management Discussion and Analysis, located on pages 8 through 77 of the Corporation's 2011 Annual Report to Shareholders, prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations,* in respect of the Corporation's annual financial statements for the year ended December 31, 2011;

“Moody’s” means Moody’s Investors Service;

“MW” means megawatt(s);

“NB Power” means New Brunswick Power Corporation;

“NEB” means National Energy Board;

“Newfoundland Hydro” means Newfoundland and Labrador Hydro;

“Newfoundland Power” means Newfoundland Power Inc.;

“OEB” means Ontario Energy Board;

“OSC” means Ontario Securities Commission;

“Other Canadian Electric Utilities” means, collectively, the operations of FortisOntario and Maritime Electric;

“PCB” means polychlorinated biphenyl;

“PEI” means Prince Edward Island;

“PEI Energy Accord” means Prince Edward Island Energy Accord;

“PEI Energy Commission” means Prince Edward Island Energy Commission;

“PJ” means petajoule(s);

“Point Lepreau” means NB Power Point Lepreau Nuclear Generating Station;

“Port Colborne Hydro” means Port Colborne Hydro Inc.;

“PRMP” means Price Risk Management Plan;

“PUB” means Newfoundland and Labrador Board of Commissioners of Public Utilities;

“ROE” means rate of return on common shareholders’ equity;

“S&P” means Standard & Poor’s;

“SEC” means U.S. Securities and Exchange Commission;

“SEDAR” means the System for Electronic Document Analysis and Retrieval;

“T&D” means transmission and distribution;

“Teck Metals” means Teck Metals Ltd.;

“TJ” means terajoule(s);

“UFCW” means United Food and Commercial Workers;

“US GAAP” means accounting principles generally accepted in the United States;

“USW” means United Steel Workers;

“Walden” means Walden Power Partnership;

“Waneta Expansion” means the 335-MW hydroelectric generating facility being constructed adjacent to the existing Waneta Plant on the Pend d’Oreille River in British Columbia;

“Waneta Partnership” means the Waneta Expansion Limited Partnership between CPC/CBT and Fortis; and

“Whistler” means the Resort Municipality of Whistler.

1.0 CORPORATE STRUCTURE

The 2011 Annual Information Form has been prepared in accordance with National Instrument 52-102 - *Continuous Disclosure Obligations*. Financial information has been prepared in accordance with Canadian GAAP and is presented in Canadian dollars unless otherwise specified.

Except as otherwise stated, the information in the 2011 Annual Information Form is given as of December 31, 2011.

Fortis includes forward-looking information in the 2011 Annual Information Form within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide Management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. 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 management. The forward-looking information in the 2011 Annual Information Form, including the 2011 MD&A incorporated herein by reference, includes, but is not limited to, statements regarding: the Corporation's focus on the United States and Canada in the acquisition of regulated utilities; the pursuit of growth in the Corporation's non-regulated businesses in support of its regulated utility growth strategy; the current environment of low natural gas prices and an abundance of shale gas reserves should help maintain the competitiveness of natural gas versus alternative energy sources in North America; investment to harvest shale oil and gas in Alberta, Canada, is expected to continue and should favourably impact energy sales and rate base investment in FortisAlberta's service territory; the expectation that the Government of British Columbia's new Natural Gas Strategy should favourably impact natural gas throughput at the FortisBC Energy companies; the expected capital investment in Canada's electricity sector over the 20-year period from 2010 through 2030; the Corporation's consolidated forecast gross capital expenditures for 2012 and in total over the next five years; the nature, timing and amount of certain capital projects and their expected costs and time to complete; the expectation that the Corporation's significant capital expenditure program should support continuing growth in earnings and dividends; there is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed; the expectation that the Corporation's regulated utilities could experience disruptions and increased costs if they are unable to maintain their asset base; forecast midyear rate base for each of the Corporation's four large Canadian regulated utilities; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long-term debt offerings; the expectation that the Corporation's subsidiaries will be able to source the cash required to fund their 2012 capital expenditure programs; the expected consolidated long-term debt maturities and repayments in 2012 and on average annually over the next five years; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to capital in the near to medium terms; the expectation that the combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets; except for debt at the Exploits Partnership, the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2012; the expectation that any increase in interest expense and/or fees associated with renewed and extended credit facilities will not materially impact the Corporation's consolidated financial results for 2012; the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the estimated impact a decrease in revenue at Fortis Properties' Hospitality Division would have on basic earnings per common share; no expected material adverse credit rating actions in the near term; the expected impact of a change in the US dollar-to-Canadian dollar foreign exchange rate on basic earnings per common share in 2012; the expectation that electricity sales growth at the Corporation's regulated utilities in the Caribbean will be minimal for 2012; the expectation that counterparties to the FortisBC Energy companies' gas derivative contracts will continue to meet their obligations; the expectation that FortisBC will continue efforts in 2012 to further integrate its gas and electricity businesses; the expectation that the Corporation's consolidated earnings and earnings per common share for 2012 will not be materially impacted by the transition to US GAAP; the expectation of an increase in consolidated defined benefit net pension cost for 2012 and the fact that there is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future; and the expected timing of the closing of the acquisition of CH Energy Group by Fortis and the expectation that the acquisition will be immediately accretive to earnings per common share, excluding one-time transaction expenses. The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; no material capital project and financing cost overrun related to the construction of the Waneta Expansion; sufficient liquidity and capital resources; the expectation that the Corporation will receive appropriate compensation from the GOB for fair value of the Corporation's investment in Belize Electricity that was expropriated by the GOB; the expectation that BECOL will not be expropriated by the GOB; the expectation that the Corporation will receive fair compensation from the Government of Newfoundland and Labrador related to the expropriation of the Exploits Partnership's hydroelectric assets and water rights; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in interest rates, foreign exchange rates, natural gas commodity prices and fuel prices; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans and environmental laws that may materially affect the operations and cash flows of the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under US GAAP beyond 2014 or the adoption of IFRS after 2014 that allows for the recognition of regulatory assets and liabilities; the continued tax-deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology infrastructure; continued favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program. 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. Factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory risk; interest rate risk, including the *uncertainty of the impact a continuation of a low interest rate environment may have on allowed ROEs of the Corporation's regulated utilities; operating and maintenance risks; risk associated with changes in economic conditions; capital project budget overrun, completion and financing risk in the Corporation's non-regulated business; capital resources and liquidity risk; risk associated with the amount of compensation to be paid to Fortis for its investment in Belize Electricity that was expropriated by the GOB; the timeliness of the receipt of the compensation and the ability of the GOB to pay the compensation owing to Fortis; risk that the GOB may expropriate BECOL; an ultimate resolution of the expropriation of the hydroelectric assets and water rights of the Exploits Partnership that differs from that which is currently expected by management; weather and seasonality risk; commodity price risk; the continued ability to hedge foreign exchange risk; counterparty risk; competitiveness of natural gas; natural gas, fuel and electricity supply risk; risk associated with the continuation, renewal, replacement and/or regulatory approval of power supply and capacity purchase contracts; risk associated with defined benefit pension plan performance and funding requirements; risks related to FEVI; environmental risks; insurance coverage risk; risk of loss of licences and permits; risk of loss of service area; risk of not being able to report under US GAAP beyond 2014 or risk that IFRS does not have an accounting standard for rate-regulated entities by the end of 2014 allowing for the recognition of regulatory assets and liabilities; risks related to changes in tax legislation; risk of failure of information technology infrastructure; risk of not being able to access First Nations lands; labour relations risk; human resources risk; and risk of unexpected outcomes of legal proceedings currently against the Corporation. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Business Risk Management" in the MD&A for the year ended December 31, 2011.*

All forward-looking information in the 2011 Annual Information Form is qualified in its entirety by the above cautionary statements 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.

1.1 Name and Incorporation

Fortis is a holding company that was incorporated as 81800 Canada Ltd. under the *Canada Business Corporations Act* on June 28, 1977 and continued under the *Corporations Act* (Newfoundland and Labrador) on August 28, 1987.

The articles of incorporation of the Corporation were amended to: (i) change its name to Fortis on October 13, 1987; (ii) set out the rights, privileges, restrictions and conditions attached to the Common Shares on October 15, 1987; (iii) designate 2,000,000 First Preference Shares, Series A on September 11, 1990; (iv) replace the class rights, privileges, restrictions and conditions attaching to the First Preference Shares and the Second Preference Shares on July 22, 1991; (v) designate 2,000,000 First Preference Shares, Series B on December 13, 1995; (vi) designate 5,000,000 First Preference Shares, Series C on May 27, 2003; (vii) designate 8,000,000 First Preference Shares, Series D and First Preference Shares, Series E on January 23, 2004; (viii) amend the redemption provisions attaching to the First Preference Shares, Series D on July 15, 2005; (ix) designate 5,000,000 First Preference Shares, Series F on September 22, 2006; (x) designate 9,200,000 First Preference Shares, Series G on May 20, 2008; and (xi) designate 10,000,000 First Preference Shares, Series H and 10,000,000 First Preference Shares, Series I on January 20, 2010.

Fortis redeemed all of its outstanding First Preference Shares, Series A and First Preference Shares, Series B on September 30, 1997 and December 2, 2002, respectively. On June 3, 2003, Fortis issued 5,000,000 First Preference Shares, Series C. On January 29, 2004, Fortis issued 8,000,000 First Preference Units, each unit consisting of one First Preference Share, Series D and one Warrant. During 2004 7,993,500 First Preference Units were converted into 7,993,500 First Preference Shares, Series E and 6,500 First Preference Shares, Series D remained outstanding. On September 20, 2005, the 6,500 First Preference Shares, Series D were redeemed by the Corporation. On September 28, 2006, Fortis issued 5,000,000 First Preference Shares, Series F. On May 23, 2008, Fortis issued 8,000,000 First Preference Shares, Series G and on June 4, 2008 issued an additional 1,200,000 First Preference Shares, Series G, following the exercise of an over-allotment option in connection with the offering of the 8,000,000 First Preference Shares, Series G. On January 26, 2010, Fortis issued 10,000,000 First Preference Shares, Series H.

The corporate head and registered office of Fortis is located at the Fortis Building, Suite 1201, 139 Water Street, P.O. Box 8837, St. John's, NL, Canada, A1B 3T2.

1.2 Inter-Corporate Relationships

Fortis is the largest investor-owned distribution utility in Canada. Its regulated holdings include electric utilities in five Canadian provinces and two Caribbean countries and a natural gas utility in British Columbia, Canada. As at December 31, 2011, regulated utility assets comprised approximately 91% of the Corporation's total assets, with the balance primarily comprised of non-regulated generation assets, primarily hydroelectric, across Canada and in Belize and Upper New York State, and hotels and commercial office and retail space in Canada.

The following table lists the principal subsidiaries of the Corporation, their jurisdictions of incorporation and the percentage of votes attaching to voting securities held directly or indirectly by the Corporation as at March 15, 2012. This table excludes certain subsidiaries, the total assets of which individually constituted less than 10% of the Corporation's consolidated assets as at December 31, 2011, or the total revenue of which individually constituted less than 10% of the Corporation's 2011 consolidated revenue. Additionally, the principal subsidiaries together comprise approximately 80% of the Corporation's consolidated assets as at December 31, 2011 and approximately 75% of the Corporation's 2011 consolidated revenue.

Principal Subsidiaries		
Subsidiary	**Jurisdiction of Incorporation**	**Percentage of votes attaching to voting securities beneficially owned, controlled or directed by the Corporation**
FHI	British Columbia	100
FortisAlberta [(1)]	Alberta	100
FortisBC Inc. [(2)]	British Columbia	100
Newfoundland Power	Newfoundland and Labrador	94 [(3)]

[(1)] *FortisAlberta Holdings, an Alberta corporation, owns all of the shares of FortisAlberta. FortisWest, a Canadian corporation, owns all of the shares of FortisAlberta Holdings. Fortis owns all of the shares of FortisWest.*

[(2)] *Fortis Pacific Holdings, a British Columbia corporation, owns all of the shares of FortisBC Inc. FortisWest, a Canadian corporation, owns all of the shares of Fortis Pacific Holdings. Fortis owns all of the shares of FortisWest.*

[(3)] *Fortis owns all of the common shares; 1,713 First Preference Shares, Series A; 36,031 First Preference Shares, Series B; 13,700 First Preference Shares, Series D and 182,300 First Preference Shares, Series G of Newfoundland Power which, at March 15, 2012, represented 94% of its voting securities. The remaining 6% of Newfoundland Power's voting securities consist of First Preference Shares, Series A, B, D and G, which are primarily held by the public.*

2.0 GENERAL DEVELOPMENT OF THE BUSINESS

2.1 Three-Year History

Over the past three years, Fortis has experienced growth in its business operations. Total assets have grown 21% from approximately $11.2 billion as at December 31, 2008 to approximately $13.6 billion as at December 31, 2011. The Corporation's shareholders' equity has also grown more than 34% from approximately $3.5 billion as at December 31, 2008 to approximately $4.7 billion as at December 31, 2011. Net earnings attributable to common equity shareholders have increased from $245 million in 2008 to $318 million in 2011.

The growth in business operations reflects the Corporation's profitable growth strategy for its principal businesses of regulated gas and electricity distribution. This strategy includes a combination of growth through acquisitions and organic growth through the Corporation's consolidated capital expenditure program.

Over the past three years, Fortis increased its regulated utility investments in Canada through the acquisition of Algoma Power for $75 million in October 2009. Algoma Power is a regulated electric distribution utility servicing approximately 12,000 customers in the District of Algoma in Ontario. The Corporation also increased its non-regulated investments, over the last three years, through the acquisition of two hotels in Canada, the construction of the Vaca hydroelectric generating facility in Belize, which was completed in March 2010, and the commencement of construction of the Waneta Expansion late in 2010.

Organic growth at the regulated utilities has been driven by the capital expenditure programs at FortisAlberta, FortisBC Electric and the FortisBC Energy companies. Total assets at FortisAlberta, FortisBC Electric and the FortisBC Energy companies have grown by approximately 49%, 29% and 15%, respectively, over the past three years.

In June 2011 the GOB expropriated the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, the Corporation discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011. For further information refer to the "Expropriated Assets" heading in Section 3.3 of this 2011 Annual Information Form.

2.2 Outlook

Operations

Over the next five years, consolidated gross capital expenditures are expected to be approximately $5.5 billion. Approximately 64% of the capital spending is expected to be incurred at the regulated electric utilities, driven by FortisAlberta and FortisBC Electric. Approximately 23% and 13% of the capital spending is expected to be incurred at the regulated gas utilities and non-regulated operations, respectively. Capital expenditures at the regulated utilities are subject to regulatory approval.

Gross consolidated capital expenditures for 2012 are expected to be approximately $1.3 billion, as summarized in the following table. 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.

Forecast Gross Consolidated Capital Expenditures [(1)] **Year Ending December 31, 2012**	
	($ millions)
FortisBC Energy Companies	244
FortisAlberta [(2)]	419
FortisBC Electric	111
Newfoundland Power	82
Other Canadian Electric Utilities	61
Regulated Electric Utilities - Caribbean	55
Non-Regulated Utility [(3)]	256
Fortis Properties	63
Total	**1,291**

(1) *Relates to forecast cash payments to acquire or construct utility capital assets, income producing properties and intangible assets, as would be reflected on the consolidated statement of cash flows. Includes forecast asset removal and site restoration expenditures, net of salvage proceeds, for those utilities where such expenditures are permissible in rate base in 2012.*

(2) *Includes forecast payments to be made to AESO for investment in transmission-related capital projects*

(3) *Includes forecast non-regulated generation, mainly related to the Waneta Expansion, and corporate capital expenditures*

The Corporation's subsidiaries expect to have reasonable access to long-term capital in 2012 to fund their capital expenditure programs.

The Corporation continues to pursue acquisitions for profitable growth, focusing on regulated electric and natural gas utilities in the United States and Canada. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

Future Accounting Changes

Due to the continued uncertainty around the adoption of a rate-regulated accounting standard by the IASB, Fortis has evaluated the option of adopting 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 file its financial statements prepared in accordance with US GAAP by qualifying as an 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 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 filed an application with the OSC seeking relief, pursuant to National Policy 11-203 – *Process for Exemptive Relief Applications in Multiple Jurisdictions*, to permit the Corporation and its reporting issuer subsidiaries to prepare their financial statements in accordance with US GAAP without qualifying as SEC Issuers (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 refers to 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. Fortis 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.

The Corporation has voluntarily prepared and filed audited US GAAP consolidated financial statements for the year ending December 31, 2011, with 2010 comparatives, as approved by the OSC. Beginning with the first quarter of 2012, the Corporation's unaudited interim consolidated financial statements will be prepared in accordance with US GAAP and filed.

Proposed Acquisition

On February 21, 2012, Fortis announced that it had entered into an agreement to acquire CH Energy Group for US$65.00 per common share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of approximately US$500 million of debt on closing. CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson Gas & Electric Corporation, is a regulated T&D utility serving approximately 300,000 electric and 75,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. The closing of the acquisition, which is expected to occur in approximately 12 months, is subject to receipt of CH Energy Group's common shareholders' approval, regulatory and other approvals, and the satisfaction of customary closing conditions. The acquisition is expected to be immediately accretive to earnings per common share, excluding one-time transaction expenses.

3.0 DESCRIPTION OF THE BUSINESS

Fortis is principally an international distribution utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets, and commercial office and retail space and hotels, which are treated as two separate segments. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each reporting segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The business segments of the Corporation are: (i) Regulated Gas Utilities - Canadian; (ii) Regulated Electric Utilities - Canadian; (iii) Regulated Electric Utilities - Caribbean; (iv) Non-Regulated – Fortis Generation; (v) Non-Regulated - Fortis Properties; and (vi) Corporate and Other.

The following sections describe the operations included in each of the Corporation's reportable segments.

3.1 Regulated Gas Utilities - Canadian

3.1.1 *FortisBC Energy Companies*

The Regulated Gas Utilities - Canadian segment comprises the natural gas T&D business of the FortisBC Energy companies.

FEI is the largest distributor of natural gas in British Columbia, serving approximately 852,000 customers in more than 100 communities. Major areas served by FEI are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of British Columbia.

FEVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island, and serves more than 102,000 customers on Vancouver Island and along the Sunshine Coast of British Columbia.

FEWI owns and operates the natural gas distribution system in Whistler, British Columbia, which provides service to more than 2,600 customers.

In addition to providing T&D services to customers, the FortisBC Energy companies also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

The FortisBC Energy companies own and operate approximately 47,200 kilometres of natural gas pipelines and met a peak day demand of 1,210 TJ in 2011.

Market and Sales

Annual customer natural gas volumes at the FortisBC Energy companies increased to 202,755 TJ in 2011 from 193,022 TJ in 2010. Revenue increased to approximately $1,568 million in 2011 from $1,546 million in 2010.

The following table compares the composition of 2011 and 2010 revenue and natural gas volumes of the FortisBC Energy companies by customer class.

FortisBC Energy Companies
Revenue and Natural Gas Volumes by Customer Class

	Revenue (%)		TJ Volumes (%)	
	2011	2010	**2011**	2010
Residential	**56.5**	56.4	**39.0**	36.3
Commercial	**28.7**	28.7	**24.2**	22.6
Industrial	**6.0**	6.0	**2.7**	2.7
	91.2	91.1	**65.9**	61.6
Transportation	**4.8**	4.6	**33.5**	31.3
Other [1]	**4.0**	4.3	**0.6**	7.1
Total	**100.0**	100.0	**100.0**	100.0

[1] *Includes amounts under fixed revenue contracts and revenue from sources other than from the sale of natural gas*

Gas Purchase Agreements

In order to ensure supply of adequate resources to provide reliable natural gas deliveries to its customers, the FortisBC Energy companies purchase supplies from a select list of producers, aggregators and marketers, while adhering to standards of counterparty creditworthiness and contract execution and/or management policies. FEI contracts for approximately 111 PJ of baseload and seasonal supply to meet the requirements of both FEI and FEWI, of which 100 PJ is sourced in north eastern British Columbia and transported to FEI's system on Spectra Energy's westcoast pipeline system, and 11 PJ is comprised of Alberta-sourced supply, transported into British Columbia via TransCanada's Alberta and British Columbia systems and then through FEI's Southern Crossing pipeline. FEVI contracts for about 11 PJ of annual supply comprised of baseload and seasonal contracts, primarily sourced in British Columbia.

Through the operation of regulatory deferrals, any difference between forecast cost of natural gas purchases, as reflected in residential and commercial customer rates, and the actual cost of natural gas purchases is recovered from, or refunded to, customers in future rates. The majority of supply contracts in the current portfolio are seasonal for either the summer period (April to October) or winter period (November to March) with a few contracts one year or longer in length.

Core market customers rely upon the FortisBC Energy companies to procure and deliver gas supply on their behalf, while FEI's transportation-only industrial customers are responsible for procuring and delivering their own gas supply directly to FEI's system, which is then delivered to their operating premises by FEI. FEI and FEVI contract for capacity on third-party pipelines, such as those owned by

Spectra Energy and TransCanada, which are regulated by the NEB, for transportation of gas supply from various market hubs and locations to FEI's system, which is then transported to the FEVI and FEWI systems. The FortisBC Energy companies pay both fixed and variable charges for the use of capacity on these pipelines, which are recovered through rates paid by core market customers. The FortisBC Energy companies contract for firm capacity in order to ensure they are able to meet their obligations to supply customers within their broad operating region under all reasonable demand scenarios.

Peak-Shaving Arrangements

The FortisBC Energy companies incorporate peak shaving and gas storage facilities into their portfolio to:

(i) supplement baseload supply in the winter months while injecting excess baseload supply to refill storage in the summer months;
(ii) eliminate the risk of supply shortages during cooler weather and peak throughput day;
(iii) effectively manage the cost of gas during winter months; and
(iv) balance daily supply and demand on the distribution system.

FEI holds approximately 29 PJ of total storage capacity, consisting of off-system capacity contracted with third parties as well as on-system peak-shaving LNG facilities, owned by FEI and FEVI. The completion of the FEVI-owned Mount Hayes LNG facility in 2011 has provided FEI with an additional 1.4 PJ of storage capacity, and 0.14 PJ of deliverability available for storage withdrawals beginning in winter 2011/2012. FEI also contracts for storage capacity from external parties at various locations throughout British Columbia, Alberta and the Pacific Northwest region of the United States. These storage facilities and supply from peak-shaving contracts can deliver a maximum daily rate of 0.7 PJ on a combined basis during the coldest months of December through February. The resources held by FEI are also used to serve FEWI.

FEVI holds a total of 3 PJ of storage capacity, including off-system capacity contracted with third parties and on-system capacity provided by the recently completed Mount Hayes LNG facility on Vancouver Island. The Mount Hayes facility provides FEVI with both peaking gas supply and system capacity during extreme cold events and emergencies.

Off-System Sales

FEI engages in off-system sales activities which allow for the recovery of, or mitigation of, costs on any unutilized supply and/or pipeline capacity that is available once customers' daily load requirements are met. In the gas contract year ending November 30, 2011, FEI marketed approximately 22 PJ of surplus gas and 62 PJ of unutilized pipeline capacity for a net pre-tax recovery of approximately $105 million. FEI has the ability to earn an incentive payment for its mitigation activities through the GSMIP approved by the BCUC. Historically, FEI has earned approximately $1 million annually through the GSMIP, while the remaining savings are credited back to customers through rates.

Following a review of the program in 2011, the BCUC approved a new framework for the GSMIP that will define the revenue sharing between customers and the shareholder for the two-year period from November 1, 2011 to October 31, 2013.

Price Risk Management Plan

In the past FEI and FEVI have engaged in hedging activities to minimize the exposure to fluctuations in the market price of natural gas through the use of derivative instruments, pursuant to a BCUC-approved PRMP. The primary objectives of the hedging strategy incorporated in the PRMP were to reduce price volatility and ensure, to the extent possible, that natural gas commodity costs remain competitive against electricity rates. In July 2010 the BCUC ordered a review of FEI's PRMP hedging strategy in the context of the *BC Clean Energy Act* and expectation of increased domestic natural gas supply. In July 2011 following an extensive review process, the BCUC determined that the hedging strategy was no longer in the best interests of customers and directed FEI to suspend the majority of its gas commodity hedging activities. FEI was further directed to manage hedges already in place through to expiry.

Following the BCUC's decision to suspend FEI's hedging activities, FEVI subsequently withdrew its request to implement a hedging strategy. FEI currently has hedges in place through to the end of October 2012 from previously approved PRMPs, but has limited hedging beyond this period. Similarly, FEVI has hedges in place through to October 2014.

The existing hedging contracts will continue in effect through to their maturity and the FortisBC Energy companies' ability to fully recover the commodity cost of gas in customer rates remains unchanged. FEI and FEVI are currently assessing alternatives to hedging to mitigate market price volatility and provide value for customers.

Unbundling

The FEI Customer Choice Program allows eligible FEI commercial and residential customers to choose to buy their natural gas commodity supply from FEI or directly from third-party marketers. FEI continues to provide delivery of the natural gas to all its customers.

The Customer Choice Program has been in place since November 2004 for commercial customers and November 2007 for residential customers. As of December 31, 2011, of the approximately 80,000 eligible commercial customers, approximately 3,500 are currently participating in the program by purchasing their commodity supply from alternate providers. Approximately 762,500 residential customers are eligible of which 101,223 customers were participating in the program as at December 31, 2011.

Legal Proceedings

During 2007 and 2008, a non-regulated subsidiary of FHI received Notices of Assessment from Canada Revenue Agency for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the Corporation's 2011 Audited Consolidated Financial Statements. FHI has begun the appeal process associated with the assessments.

In 2009 FHI was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to the rupture in July 2007 of an oil pipeline owned and operated by Kinder Morgan, Inc. FHI has filed a statement of defence. During the second quarter of 2010, FHI was added as a third party in all of the related actions and all claims are expected to be tried at the same time. The amount and outcome of the actions are indeterminable at this time and, accordingly, no amount has been accrued in the Corporation's 2011 Audited Consolidated Financial Statements.

Human Resources

As at December 31, 2011, the FortisBC Energy companies employed 1,789 full-time equivalent employees. Approximately 71% of the employees are represented by IBEW, Local 213, and COPE, Local 378, under collective agreements. The IBEW collective agreement expired March 31, 2011 and is currently being negotiated, while the COPE collective agreement expires on March 31, 2012.

3.2 Regulated Electric Utilities - Canadian

3.2.1 *FortisAlberta*

FortisAlberta is a regulated electric distribution utility in the province of Alberta. Its business is the ownership and operation of regulated electricity distribution facilities that distribute electricity, generated by other market participants, from high-voltage transmission substations to end-use customers. FortisAlberta is not involved in the generation, transmission or direct sale of electricity. FortisAlberta owns and/or operates the electricity distribution system in a substantial portion of southern and central Alberta, totalling approximately 114,000 kilometres of distribution lines. The Company's distribution network serves approximately 499,000 customers, comprising residential, commercial, farm, oil and gas and industrial consumers of electricity, and met a peak demand of 2,505 MW in 2011.

Market and Sales

FortisAlberta's annual energy deliveries increased to 16,367 GWh in 2011 from 15,866 GWh in 2010. Revenue was $409 million in 2011 compared to $385 million in 2010.

The following table compares the composition of FortisAlberta's 2011 and 2010 revenue and energy deliveries by customer class.

FortisAlberta Revenue and Energy Deliveries by Customer Class				
	Revenue (%)		GWh Deliveries [1] (%)	
	2011	2010	**2011**	2010
Residential	**31.2**	27.6	**17.0**	17.0
Large commercial and industrial [2]	**20.9**	18.6	**61.0**	61.3
Farms	**13.1**	11.5	**7.9**	7.5
Small commercial	**11.2**	10.0	**7.9**	7.9
Small oilfield	**9.0**	8.1	**5.8**	5.8
Other [3]	**14.6**	24.2	**0.4**	0.5
Total	**100.0**	100.0	**100.0**	100.0

(1) *GWh percentages presented exclude FortisAlberta's GWh deliveries to "transmission-connected" customers. These deliveries were 7,100 GWh in each of 2011 and 2010 and consisted primarily of energy deliveries to large-scale industrial customers directly connected to the transmission grid.*

(2) *Includes large oilfield customers*

(3) *Includes revenue from sources other than the delivery of energy, including that related to street-lighting services, rate riders, deferrals and adjustments*

Franchise Agreements

FortisAlberta's customers, located within a city, town, or village boundary, are served through franchise agreements between the Company and the customers' municipality of residence. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta that are located in their municipal boundaries. In Alberta, the standard franchise agreement is generally for ten years and may be renewed for five years upon mutual consent of the parties. All municipal franchises are governed by legislation that requires the municipality or the utility to give notice and obtain AUC approval if it intends to terminate its franchise agreement. Any franchise agreement that is not renewed continues in effect until either the Company or the municipality terminates it with AUC permission. If a franchise agreement is terminated and the municipality subsequently exercises its right under the *Municipal Government Act* (Alberta) to purchase FortisAlberta's distribution network within the municipality's boundaries, the Company must be compensated. Compensation would include payment for FortisAlberta's assets on the basis of a methodology approved by the AUC.

Additionally, under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric distribution system expands its boundaries, the municipality can acquire the Company's assets in the annexed area. In such circumstances, the *Hydro and Electricity Energy Act* (Alberta) provides that the AUC may determine that the municipality should pay compensation to the Company for any facilities transferred on the basis of replacement cost less depreciation.

FortisAlberta holds franchise agreements with 140 municipalities, 107 of these agreements that were set to expire in 2011 were renewed for a further five years. In addition, a new standardized franchise agreement has been developed by FortisAlberta and the Alberta Urban Municipalities Association with a standard term of 10 years, and the Company will seek AUC approval of the new standardized franchise agreement in the first quarter of 2012. If the form of agreement is approved by the AUC, FortisAlberta will begin the process of moving all 140 municipalities to the new agreement.

Human Resources

As at December 31, 2011, FortisAlberta had 1,036 full-time equivalent employees. Approximately 75% of the employees of the Company are members of a labour association represented by United Utility Workers' Association, Local 200, under a three-year collective agreement that expires on December 31, 2013.

3.2.2 *FortisBC Electric*

FortisBC Electric includes FortisBC Inc., 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. FortisBC Inc. serves a diverse mix of approximately 162,000 customers, of whom approximately 113,000 are served directly by the Company's assets while the remainder are served through the wholesale supply of power to municipal distributors. In 2011 FortisBC Inc. met a peak demand of 669 MW. Residential customers represent the largest customer class of the Company. FortisBC Electric's T&D assets include approximately 7,000 kilometres of T&D lines and 65 substations.

FortisBC Electric also includes operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals and BC Hydro, the 149-MW Brilliant hydroelectric plant and 120-MW Brilliant hydroelectric expansion plant, both owned by CPC/CBT, the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT, and the distribution system owned by the City of Kelowna.

Market and Sales

FortisBC Electric has a diverse customer base composed primarily of residential, general service, industrial and municipal wholesale, and other industrial customers. Annual electricity sales were 3,143 GWh in 2011 compared to 3,046 GWh in 2010. Revenue increased to $296 million in 2011 from $266 million in 2010.

The following table compares the composition of FortisBC Electric's 2011 and 2010 revenue and electricity sales by customer class.

FortisBC Electric
Revenue and Electricity Sales by Customer Class

	Revenue (%)		**GWh Sales (%)**	
	2011	2010	**2011**	2010
Residential	**43.7**	43.0	**40.1**	40.2
General service	**22.8**	24.3	**22.4**	23.2
Wholesale	**19.7**	19.5	**28.5**	28.9
Industrial	**7.4**	6.1	**9.0**	7.7
Other (1)	**6.4**	7.1	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes revenue from sources other than from the sale of electricity, including revenue of Fortis Pacific Holdings associated with non-regulated operating, maintenance and management services*

Generation and Power Supply

FortisBC Inc. meets the electricity supply requirements of its customers through a mix of its own generation and power purchase contracts. FortisBC Inc. owns four regulated hydroelectric generating plants on the Kootenay River with an aggregate capacity of 223 MW, which provide approximately 45% of the Company's energy needs and 30% of its peak capacity needs. FortisBC Inc. meets the balance of its requirements through a portfolio of long-term and short-term power purchase agreements. Since 1998, 11 of 15 FortisBC hydroelectric generation units have been subject to a life extension and upgrade program, which substantially concluded in 2011.

FortisBC Inc.'s four hydroelectric generating facilities are governed by the CPA. The CPA is a multi-party agreement that enables the five separate owners of eight major hydroelectric generating plants, with a combined capacity of 1,565 MW and located in relatively close proximity to each other, to coordinate the operation and dispatch of their generating plants.

The following table lists the plants and their owners.

Plant	Capacity (MW)	Owners
Canal Plant	580	BC Hydro
Waneta Dam	493	Teck Metals and BC Hydro [(1)]
Kootenay River System	223	FortisBC Inc.
Brilliant Dam and Expansion	269	BPC and BEPC
Total	**1,565**	

[(1)] *During 2010 BC Hydro acquired a one-third interest in the Waneta Dam.*

BPC, BEPC, Teck Metals and FortisBC Inc. are collectively defined in the CPA as the Entitlement Parties. 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 resources 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 facilities, each of the Entitlement Parties is contractually entitled to a fixed annual entitlement of capacity and energy from BC Hydro, which is currently based on 50-year historical water flows. The Entitlement Parties receive their defined entitlements irrespective of actual water flows to the Entitlement Parties' generating plants and are, accordingly, insulated from the risk of water availability. 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.

The majority of FortisBC Inc.'s remaining electricity supply is acquired through long-term power purchase contracts, consisting of the following:

i. a 149-MW long-term power purchase agreement with BPC terminating in 2056;
ii. a 200-MW power purchase agreement with BC Hydro terminating in 2013; and
iii. a number of small power purchase contracts with independent power producers.

The majority of these purchase contracts have been accepted by the BCUC and prudently incurred costs thereunder flow through to customers through FortisBC Inc.'s electricity rates.

Although FortisBC Inc. can currently meet the majority of its customer supply requirements from its own generation and the major power purchase agreements described above, there are instances where a portion of the customer load 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 incurred and accurately forecasted, are recovered through customer rates.

In October 2010 the Corporation, in partnership with CPC/CBT, concluded definitive agreements to construct the Waneta Expansion. Fortis owns a controlling 51% interest in the Waneta Expansion Partnership and will operate and maintain the Waneta Expansion, through FortisBC, when it comes into service, which is expected in spring 2015. The Waneta Expansion will be included in the CPA and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing hydrologic risk associated with the project. The energy, approximately 630 GWh, and associated capacity required to deliver such energy for the Waneta Expansion, will be sold to BC Hydro under a long-term energy purchase agreement. The surplus capacity, equal to 234 MW on an average annual basis, will be sold to FortisBC over 40 years under the Waneta Expansion Capacity Agreement, which was accepted for filing by the BCUC in September 2010 and was executed in November 2011. The BCUC will be seeking submissions on whether further public process is warranted in respect of its acceptance of the November 2011 filing of the executed Waneta Expansion Capacity Agreement. For additional information refer to Section 3.4 of this 2011 Annual Information Form.

Legal Proceedings

The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC Inc. dated August 2, 2005. The Government 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 landowners 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 Inc. 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 Corporation's 2011 Audited Consolidated Financial Statements.

Human Resources

As at December 31, 2011, FortisBC Inc. had 528 full-time equivalent employees. FortisBC Inc. has a collective agreement with COPE, Local 378, that expired on January 31, 2011 and a collective agreement with IBEW, Local 213, expiring on January 31, 2013. The two collective agreements cover approximately 73% of employees.

FortisBC Inc. and COPE, Local 378, have reached an agreement with regard to certain customer service employees. Discussions continue with regard to the remaining COPE bargaining unit.

3.2.3 *Newfoundland Power*

Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving more than 247,000 customers, or 87%, of the province's electricity consumers. Newfoundland Power met a peak demand of 1,166 MW in 2011. The balance of the population is served by Newfoundland's other electric utility, Newfoundland Hydro, which also serves several larger industrial customers. Newfoundland Power owns and operates approximately 11,200 kilometres of T&D lines.

Market and Sales

Annual weather-adjusted electricity sales increased to 5,553 GWh in 2011 from 5,419 GWh in 2010. Revenue increased to $573 million in 2011 from $555 million in 2010.

The following table compares the composition of Newfoundland Power's 2011 and 2010 revenue and electricity sales by customer class.

Newfoundland Power
Revenue and Electricity Sales by Customer Class

	Revenue (1) **(%)**		**GWh Sales** (1) **(%)**	
	2011	2010	**2011**	2010
Residential	**60.4**	60.2	**61.3**	61.1
Commercial and Street Lighting	**36.0**	36.2	**38.7**	38.9
Other (2)	**3.6**	3.6	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Revenue and electricity sales reflect weather-adjusted values pursuant to Newfoundland Power's weather normalization reserve.*
(2) *Includes revenue from sources other than from the sale of electricity, largely composed of joint-use pole-related revenue.*

Power Supply

Approximately 93% of Newfoundland Power's energy requirements is purchased from Newfoundland Hydro. The principal terms of the supply arrangements with Newfoundland Hydro are regulated by the PUB on a basis similar to that upon which Newfoundland Power's service to its customers is regulated.

Newfoundland Power operates 29 small generating facilities, which generate approximately 7% of the electricity sold by Newfoundland Power. The Company's hydroelectric generating plants have a total capacity of 97 MW. The diesel plants and gas turbines have a total capacity of approximately 7 MW and 36 MW, respectively.

Legal Proceedings

The City of St. John's has given formal notice of its intention to terminate Newfoundland Power's rights to use the Mobile River watershed for the generation of electricity. The effective date of the notice to terminate the lease was March 1, 2009. The Company held these rights under a lease dated November 23, 1946, which was amended by an agreement dated October 21, 1949. The two hydroelectric generating plants affected by the lease have a combined capacity of approximately 12 MW and generate annual production of 49 GWh, representing less than 1% of the Company's total energy requirements. To exercise the termination provision of the lease, the City of St. John's is required to pay to the Company the value of all works and erections employed in the generation and transmission of electricity using the water of the Mobile River watershed. In accordance with the terms of the lease, an arbitration panel was appointed in 2008 for the purpose of determining the value of the affected assets. On March 9, 2009, the panel issued a ruling on certain preliminary questions. A majority of the panel ruled that termination of the lease will not be effective until payment to the Company of the value of the assets, and that the value of the payment is to be based on a valuation of the assets as a going concern, including the land and water rights.

The City of St. John's has applied to the Supreme Court of Newfoundland and Labrador to have the preliminary ruling of the arbitration panel set aside. On November 12, 2010, the Supreme Court issued a decision dismissing the City's application, and awarding court costs to Newfoundland Power. In December 2010 the city appealed the Supreme Court's decision to the Newfoundland and Labrador Court of Appeal. A hearing date for the appeal has not yet been set.

Human Resources

As at December 31, 2011, Newfoundland Power had 640 full-time equivalent employees, of which approximately 54% were members of bargaining units represented by IBEW, Local 1620.

The Company has two collective agreements governing its union employees represented by IBEW, Local 1620. Both collective agreements expired September 30, 2011. Newfoundland Power and the IBEW reached a tentative agreement in January 2012 that is subject to member ratification.

Recent Developments

In December 2010 Newfoundland Power and Bell Aliant signed a new Support Structure Agreement, effective January 1, 2011, whereby Bell Aliant was to buy back 40% of all joint-use poles and related infrastructure owned by Newfoundland Power for approximately $46 million. Newfoundland Power had filed an application with the PUB requesting approval of the transaction and the approval was received in September 2011. In October 2011 Newfoundland Power received proceeds of $46 million from Bell Aliant reflecting the estimated purchase price. Based on results of a pole survey completed in late 2011, a purchase price adjustment of approximately $1 million was paid to Bell Aliant from Newfoundland Power in January 2012.

3.2.4 *Other Canadian Electric Utilities*

Other Canadian Electric Utilities includes the operations of Maritime Electric and FortisOntario.

<u>Maritime Electric</u>
The Corporation, through FortisWest, holds all of the common shares of Maritime Electric. Maritime Electric is an integrated electric utility that directly supplies more than 75,000 customers, constituting 90% of electricity consumers on PEI. Maritime Electric purchases most of the energy it distributes to its customers from NB Power, a provincial Crown Corporation, through various energy purchase agreements. Maritime Electric's system is connected to the mainland power grid via two submarine cables between PEI and New Brunswick, which are leased from the Government of PEI. Maritime Electric owns and operates generating plants with a combined capacity of 150 MW on PEI and met a peak demand of 224 MW in 2011. Maritime Electric owns and operates approximately 5,500 kilometres of T&D lines.

<u>FortisOntario</u>
The Corporation's wholly owned regulated utility investments in Ontario, collectively FortisOntario, provide integrated electric utility service to more than 64,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro, which has

been leased from the City of Port Colborne under a 10-year lease agreement that expires in April 2012. In April 2011 FortisOntario provided the City of Port Colborne and Port Colborne Hydro with an irrevocable written notice of FortisOntario's election to exercise the purchase option, under the current operating lease agreement, at the purchase price of approximately $7 million on April 15, 2012. The purchase constitutes the sale of the remaining assets of Port Colborne Hydro to FortisOntario. The purchase is subject to OEB approval. FortisOntario also owns a 10% interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies serving approximately 38,000 customers.

FortisOntario met a combined peak demand of 276 MW in 2011. FortisOntario owns and operates approximately 3,300 kilometres of T&D lines.

Market and Sales

Annual electricity sales were 2,366 GWh in 2011 compared to 2,328 GWh in 2010. Revenue was $339 million in 2011 compared to $331 million in 2010.

The following table compares the composition of Other Canadian Electric Utilities' 2011 and 2010 revenue and electricity sales by customer class.

Other Canadian Electric Utilities Revenue and Electricity Sales by Customer Class				
	Revenue (%)		**GWh Sales (%)**	
	2011	2010	**2011**	2010
Residential	**43.4**	42.5	**43.2**	42.9
Commercial and industrial	**48.5**	49.1	**55.9**	56.4
Other [(1)]	**8.1**	8.4	**0.9**	0.7
Total	**100.0**	100.0	**100.0**	100.0

[(1)] *Includes revenue from sources other than from the sale of electricity*

Power Supply

Maritime Electric

Maritime Electric purchased 83% of the electricity required to meet its customers' needs from NB Power in 2011. The balance was met through the purchase of wind energy produced on PEI. Maritime Electric's on-Island generation facilities are used primarily for peaking, submarine-cable loading issues and emergency purposes.

Maritime Electric generally receives a portion of its electricity requirements from Point Lepreau. A major refurbishment of Point Lepreau began in 2008 and is expected to be completed by fall 2012, extending the facility's estimated life an additional 25 years. The nature and timing of recovery of $47 million of deferred incremental replacement energy costs during the refurbishment of Point Lepreau up to the end of February 2011 is to be determined by the PEI Energy Commission, which was established by the Government of PEI in 2011.

On November 12, 2010, Maritime electric signed the PEI Energy Accord with the Government of PEI. The PEI Energy Accord covers the period from March 1, 2011 through February 29, 2016. The PEI Energy Accord provides rate reductions effective March 1, 2011 and price stability and rate predictability for the subsequent two years.

The combination of reduced energy input costs associated with a new five-year energy purchase agreement with NB Power effective March 1, 2011 and the assumption, by the Government of PEI, of certain energy related costs beginning on March 1, 2011 as stipulated in the PEI Energy Accord, has contributed to lower costs for consumers since March 1, 2011. Maritime Electric's exposure with respect to premiums for replacement energy during the refurbishment of Point Lepreau has been capped at $47 million as of February 2011 as noted above.

The *Renewable Energy Act* (PEI) requires Maritime Electric to source 15% of its annual energy sales from renewable energy sources. Approximately 17% of total energy supply was derived from wind-powered generation in 2011.

<u>FortisOntario</u>
The power requirements of FortisOntario's service areas are provided from various sources. Canadian Niagara Power purchases its power requirements for Fort Erie and Port Colborne from IESO. Canadian Niagara Power purchases approximately 88% of energy requirements for Gananoque through monthly energy purchases from Hydro One and the remaining 12% is purchased, through the Hydroelectric Contract Initiative, from five hydroelectric generating plants owned by Fortis Properties. Algoma Power purchases 100% of its energy from IESO.

Under the Standard Supply Code of the OEB, Canadian Niagara Power and Algoma Power are obliged to provide Standard Service Supply to all its customers who do not choose to contract with an electricity retailer. This energy is provided to customers at either regulated or market prices.

Cornwall Electric purchases 100% of its power requirements from Hydro-Québec Energy Marketing under two fixed-term contracts. The first contract, which represents approximately 40% of the power supply, is a 45-MW contract with a 60% capacity factor. The second contract, supplying the remainder of Cornwall Electric's energy requirements, is a 100-MW capacity and energy contract. Both contracts expire in December 2019.

Human Resources

As at December 31, 2011, Maritime Electric had 181 full-time equivalent employees, of which approximately 70% were represented by IBEW, Local 1432. The current collective agreement expires December 31, 2013.

As at December 31, 2011, FortisOntario had 198 full-time equivalent employees, of which approximately 58% were represented by CUPE, Local 137, and IBEW, Local 636, in the Niagara Region; IBEW, Local 636, in Gananoque; and Power Workers Union, a CUPE affiliate as CUPE, Local 1000, in the Algoma region. The collective agreements governing these employees expire on April 30, 2012; May 31, 2012; July 31, 2012; and December 31, 2012, respectively.

3.3 *Regulated Electric Utilities - Caribbean*

Regulated Electric Utilities - Caribbean operations are comprised of Caribbean Utilities, Fortis Turks and Caicos, and Belize Electricity up to June 20, 2011.

Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 27,000 customers. The Company met a peak demand of approximately 99 MW in 2011. Caribbean Utilities owns and operates approximately 639 kilometres of T&D lines. Fortis holds an approximate 60% (December 31, 2010 - 59%) controlling ownership interest in the utility. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U).

Fortis Turks and Caicos is an integrated electric utility, indirectly wholly owned by Fortis, serving more than 9,500 customers, or 85%, of electricity consumers, in the Turks and Caicos Islands. The utility met a combined peak demand of approximately 30 MW in 2011. Fortis Turks and Caicos owns and operates approximately 538 kilometres of T&D lines. The Company is the principal distributor of electricity in the Turks and Caicos Islands pursuant to 50-year licences that expire in 2036 and 2037.

Market and Sales

Annual electricity sales decreased to 918 GWh in 2011 from 1,150 GWh in 2010. Annual revenue decreased to $305 million in 2011 from $333 million in 2010. The decrease in annual electricity sales and revenue was largely due to the expropriation of Belize Electricity by the GOB in June 2011 and the consequential loss of control resulting in the discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011. For further information refer to the "Expropriated Assets" section that follows.

The following table compares the composition of Regulated Electric Utilities - Caribbean's revenue and electricity sales by customer class for the years ended 2011 and 2010.

Regulated Electric Utilities - Caribbean (1) Revenue and Electricity Sales by Customer Class				
	Revenue (%)		GWh Sales (%)	
	2011	2010	**2011**	2010
Residential	**46.6**	48.6	**45.5**	48.3
Commercial, industrial and street lighting	**52.5**	49.4	**54.5**	51.7
Other (2)	**0.9**	2.0	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes Caribbean Utilities and Fortis Turks and Caicos, and Belize Electricity up to June 20, 2011*
(2) *Includes revenue from sources other than from the sale of electricity*

Power Supply

Caribbean Utilities relies upon in-house diesel-powered generation to produce electricity for Grand Cayman. Grand Cayman has neither hydroelectric potential nor inherent thermal resources and the Company must rely upon diesel fuel imported to Grand Cayman primarily from refineries in the Caribbean and the Gulf of Mexico. The Company has an installed generating capacity of approximately 151 MW.

Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80% of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-powered generating plant. The initial contract was for three years and terminated in April 2010. Caribbean Utilities continues to operate within the terms of the initial contract. The contract contains an automatic renewal clause for the years 2010 through 2012. Should any party choose to terminate the contract within that two-year period, notice must be given a minimum of one year in advance of the desired termination date. As at December 31, 2011, no such termination notice has been given by either party. As such, the contract is effectively renewed until May 2012. The quantity of fuel to be purchased under the contract for 2012 is approximately 10 million imperial gallons.

Fortis Turks and Caicos relies upon in-house diesel-powered generation, which has a combined generating capacity of 65 MW, to produce electricity for its customers.

Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

Expropriated Assets

On June 20, 2011, the GOB enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, the Corporation discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011, and has classified the book value of the previous investment in the utility as a long-term other asset on the consolidated balance sheet. As at December 31, 2011, the long-term other asset, including foreign exchange impacts, totalled $106 million.

In October 2011 Fortis commenced an action in the Belize Supreme Court to challenge the legality of the expropriation of its investment in Belize Electricity. Fortis commissioned an independent valuation of its expropriated investment in Belize Electricity and submitted its claim for compensation to the GOB in November 2011. The GOB also commissioned an independent valuation of Belize Electricity and communicated the results of such valuation in its response to the Corporation's claim for compensation. The fair value determined under the GOB's valuation is significantly lower than the fair value determined under the Corporation's valuation. Pursuant to the expropriation action, Fortis is assessing alternative options for obtaining fair compensation from the GOB.

Human Resources

As at December 31, 2011, Regulated Electric Utilities - Caribbean employed 307 full-time equivalent employees. The 193 employees at Caribbean Utilities and 114 employees at Fortis Turks and Caicos are non-unionized.

3.4 Non-Regulated - Fortis Generation

The following table summarizes the Corporation's non-regulated generation assets by location.

Fortis Generation Non-Regulated Generation Assets			
Location	**Plants**	**Fuel**	**Capacity (MW)**
Belize	3	hydro	51
Ontario	7	hydro, thermal	13
Central Newfoundland [(1)]	2	hydro	36
British Columbia [(2)]	1	hydro	16
Upper New York State	4	hydro	23
Total	**17**		**139**

(1) *The two central Newfoundland facilities were expropriated by the Government of Newfoundland and Labrador in December 2008. Effective February 12, 2009, the Corporation discontinued the consolidation method of accounting for its investment in central Newfoundland.*

(2) *Once completed, the Waneta Expansion will provide an additional 335 MW of hydroelectric generating capacity in British Columbia.*

The Corporation's non-regulated generation operations consist of its 100% ownership interest in each of BECOL, FortisOntario and FortisUS Energy, as well as non-regulated generation assets owned by Fortis Properties, FortisBC Inc., and by Fortis through its 51% controlling ownership interest in the Waneta Partnership.

Non-regulated generation operations in Belize consist of the 25-MW Mollejon, 7-MW Chalillo and, as of March 2010, 19-MW Vaca hydroelectric generating facilities. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary BECOL under a franchise agreement with the GOB. In October 2011 the GOB purportedly amended the Constitution of Belize to require majority government ownership of three public utility providers, including Belize Electricity, but excluding BECOL. The GOB has also indicated it has no intention to expropriate BECOL. Fortis continues to control and consolidate the financial statements of BECOL.

Non-regulated generation operations of FortisOntario include the operation of a 5-MW gas-powered cogeneration plant in Cornwall. All energy output of this plant is sold to Cornwall Electric. Fortis Properties owns and operates six small hydroelectric generating facilities in eastern Ontario with a combined capacity of 8 MW. The electricity produced from these facilities is sold to the Ontario Power Association, via the Hydroelectric Contract Initiative, under fixed-price contracts.

Fortis Properties also has a non-regulated generation investment in central Newfoundland that is held through the Company's direct 51% interest in the Exploits Partnership. Through the Exploits Partnership, 36 MW of additional capacity was developed and installed at two of Abitibi's hydroelectric generating facilities in central Newfoundland. The Exploits Partnership sells its output to Newfoundland Hydro under a 30-year power purchase agreement expiring in 2033. Effective February 2009, the Corporation discontinued the consolidation method of accounting for these operations, necessitated by the actions of the Government of Newfoundland and Labrador related to its expropriation of the hydroelectric assets and water rights of the Exploits Partnership. Refer to the "Expropriated Assets" section that follows.

The non-regulated generation operations of FortisBC Inc. include the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia that sells its entire output to BC Hydro under a power purchase agreement expiring in 2013. Effective October 1, 2010, non-regulated generation operations in British Columbia include the Corporation's 51% controlling ownership interest in the Waneta Partnership, with CPC/CBT holding the remaining 49% interest. Construction of the Waneta Expansion commenced late in 2010 for completion expected in spring 2015 at an estimated cost of approximately $900 million. SNC-Lavalin was awarded a contract for approximately

$590 million to design and build the Waneta Expansion. Approximately $244 million has been spent on this project since construction began late 2010. Major construction activities on-site include the completion of the excavation of the intake, powerhouse and power tunnels. Construction progress is going well and the project is currently on schedule. For additional information refer to Section 3.2.2 of this 2011 Annual Information Form.

Through FortisUS Energy, an indirectly wholly owned subsidiary, the Corporation owns and operates four hydroelectric generating facilities in Upper New York State with a combined capacity of approximately 23 MW operating under licences from the United States Federal Energy Regulatory Commission. All four hydroelectric generating facilities sell energy at market rates through purchase agreements with Niagara Mohawk Power Corporation.

Market and Sales

Annual energy sales from non-regulated generation assets were 389 GWh in 2011 compared to 427 GWh in 2010. Revenue was $34 million in 2011 compared to $36 million in 2010.

The following table compares the composition of Fortis Generation's 2011 and 2010 revenue and energy sales by location.

Fortis Generation Revenue and Energy Sales by Location				
	Revenue (%)		GWh Sales (%)	
	2011	2010	**2011**	2010
Belize [(1)]	**65.8**	68.9	**60.2**	60.6
Ontario	**13.3**	11.2	**12.0**	11.7
Central Newfoundland [(2)]	**4.1**	3.9	**-**	-
British Columbia	**6.7**	5.6	**10.3**	8.4
Upper New York State	**10.1**	10.4	**17.5**	19.3
Total	**100.0**	100.0	**100.0**	100.0

(1) *Results reflect contribution from the Vaca hydroelectric generating facility in Belize from March 2010 when the facility was commissioned*

(2) *Reflects the discontinuance of the consolidation method of accounting for the financial results of the operations in central Newfoundland, effective February 12, 2009*

Expropriated Assets

Exploits Partnership

In December 2008 the Government of Newfoundland and Labrador expropriated Abitibi's hydroelectric assets and water rights in Newfoundland, including those of the Exploits Partnership. The newsprint mill in Grand Falls-Windsor closed on February 12, 2009, subsequent to which the day-to-day operations of the Exploits Partnership's hydroelectric generating facilities were assumed by Nalcor Energy as an agent for the Government of Newfoundland and Labrador with respect to expropriation matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi in the province. The loss of control over cash flows and operations required Fortis to cease consolidation of the Exploits Partnership, effective February 12, 2009. Discussions between Fortis Properties and Nalcor Energy with respect to expropriation matters are ongoing.

Human Resources

As at December 31, 2011, Fortis Generation employed 39 full-time equivalent personnel, none of whom participate in a collective agreement.

3.5 Non-Regulated - Fortis Properties

As a wholly owned subsidiary of Fortis, Fortis Properties is the Corporation's vehicle for non-utility diversification and growth. The Company owns and operates 22 hotels, collectively representing 4,300 rooms, in eight Canadian provinces, and approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada. Fortis Properties is currently constructing a $47 million 12-storey office building in downtown St. John's, Newfoundland. The building will feature 152,000 square feet of Class A office space and include 261 parking spaces. Construction is expected to be completed in the second half of 2013.

Revenue was $231 million in 2011 compared to $226 million in 2010. In 2011 Fortis Properties derived approximately 29% of its revenue from real estate operations and 71% of its revenue from hotel operations. Fortis Properties derived approximately 44% of its 2011 operating income from real estate operations and 56% from hotel operations.

Fortis Properties' Real Estate Division is anchored by high-quality tenants under long-term leases. The Real Estate Division ended 2011 with 93.2% occupancy, compared to 94.5% occupancy at the end of 2010. In contrast, the average national occupancy rate was 91.9% at the end of 2011, compared to 90.5% at the end of 2010.

The following table sets out the office and retail properties owned by Fortis Properties.

Fortis Properties
Office and Retail Properties

Property [(1)]	Location	Type of Property	Gross Lease Area *(square feet 000's)*
Fort William Building	St. John's, NL	Office	188
Cabot Place I	St. John's, NL	Office	135
TD Place	St. John's, NL	Office	94
Fortis Building	St. John's, NL	Office	83
Multiple Office	St. John's, NL	Office and Retail	75
Millbrook Mall	Corner Brook, NL	Retail	118
Fraser Mall	Gander, NL	Retail	99
Marystown Mall	Marystown, NL	Retail	87
Fortis Tower	Corner Brook, NL	Office	69
Maritime Centre	Halifax, NS	Office and Retail	565
Brunswick Square	Saint John, NB	Office and Retail	511
Kings Place	Fredericton, NB	Office and Retail	292
Blue Cross Centre	Moncton, NB	Office and Retail	324
Delta Regina	Regina, SK	Office	52
Total			**2,692**

[(1)] *The Viking Mall property in St. Anthony, Newfoundland was sold in January 2011.*

Revenue per available room at the Hospitality Division of Fortis Properties, excluding the impact of the Hilton Suites Winnipeg Airport hotel acquired in October 2011, increased to $78.48 for 2011 from $76.83 for 2010. The increase was the result of an increase in the average daily room rate, partially offset by a slight decrease in hotel occupancy. The average daily room rate, excluding the impact of the Hilton Suites Winnipeg Airport hotel, increased to $127.59 for 2011 from $124.17 for 2010, while the average occupancy for 2011 was 61.5%, down from the 61.9% achieved in 2010. Including the Hilton Suites Winnipeg Airport hotel, revenue per available room was $78.76 for 2011.

The hotels owned and managed by Fortis Properties are summarized as follows.

Fortis Properties Hotels			
Hotels	**Location**	**Number of Guest Rooms**	**Conference Facilities** *(000's square feet)*
Delta St. John's	St. John's, NL	403	21
Holiday Inn St. John's	St. John's, NL	252	12
Sheraton Hotel Newfoundland	St. John's, NL	301	18
Mount Peyton	Grand Falls-Windsor, NL	148	5
Greenwood Inn Corner Brook	Corner Brook, NL	102	5
Four Points by Sheraton Halifax	Halifax, NS	177	12
Delta Sydney	Sydney, NS	152	6
Delta Brunswick	Saint John, NB	254	18
Holiday Inn Kitchener - Waterloo	Kitchener-Waterloo, ON	184	13
Holiday Inn Peterborough	Peterborough, ON	153	6
Holiday Inn Sarnia	Point Edward, ON	217	11
Holiday Inn Cambridge	Cambridge, ON	143	7
Holiday Inn Select Windsor	Windsor, ON	214	17
Greenwood Inn Calgary	Calgary, AB	210	9
Holiday Inn Edmonton (1)	Edmonton, AB	224	8
Greenwood Inn Winnipeg	Winnipeg, MB	213	8
Hilton Suites Winnipeg Airport (2)	Winnipeg, MB	160	9
Holiday Inn Lethbridge (3)	Lethbridge, AB	119	5
Holiday Inn Express and Suites Medicine Hat	Medicine Hat, AB	93	1
Best Western Medicine Hat	Medicine Hat, AB	122	-
Holiday Inn Express Kelowna	Kelowna, BC	190	5
Delta Regina	Regina, SK	274	24
Total		**4,305**	**220**

(1) *In December 2011 the Greenwood Inn Edmonton was rebranded to Holiday Inn Edmonton*

(2) *Fortis Properties acquired the Hilton Suites Winnipeg Airport hotel in October 2011, a 160-room, full-service hotel with over 8,500 square feet of meeting space*

(3) *In June 2011 the Ramada Hotel & Suites Lethbridge was rebranded to Holiday Inn Lethbridge*

Human Resources

As at December 31, 2011, Fortis Properties employed approximately 2,400 full-time equivalent employees, approximately 47% of whom are represented by unions listed in the following table.

Fortis Properties Unions			
Property	**Union**	**Expiry of Agreement**	**Number of Unionized Employees**
Holiday Inn St. John's	CAW	August 31, 2012	55
Delta St. John's	UFCW	December 31, 2012	256
Greenwood Inn Corner Brook	CAW	March 11, 2013	46
East Side Mario's St. John's	CAW	July 31, 2013	90
Delta Sydney (1)	CAW	September 30, 2011	76
Delta Brunswick & Brunswick Square	USW	June 10, 2013	123
Delta Regina	CEP	May 3, 2014	173
St. John's Real Estate	IBEW	April 17, 2013	10
Sheraton Hotel Newfoundland	CAW	March 31, 2015	191
Holiday Inn Select Windsor	UFCW	April 30, 2013	49
Mount Peyton (1)	UFCW	December 1, 2011	56
Total			**1,125**

(1) *Collective bargaining has commenced.*

4.0 REGULATION

Each of the Corporation's utilities operates under a cost of service methodology and is regulated by the regulatory body in its respective operating jurisdiction. FortisBC Electric was also subject to performance based rate setting to the end of 2011, which provided the utility the opportunity to earn in excess of its allowed ROE. With regulated utilities in seven different jurisdictions, Fortis has significant regulatory expertise.

For information with respect to the nature of regulation and material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities, refer to the "Regulatory Highlights" section of the Corporation's MD&A and to Note 2 of the Corporation's 2011 Audited Consolidated Financial Statements.

5.0 ENVIRONMENTAL MATTERS

The Corporation and its Canadian subsidiaries are subject to various federal, provincial and municipal laws, regulations and guidelines relating to the protection of the environment including, but not limited to, wildlife, water and land protection, emissions and the proper storage, transportation, recycling and disposal of hazardous and nonhazardous 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 their commencement.

Several key Canadian federal environmental laws and regulations affecting the operations of the Corporation's Canadian subsidiaries include, but are not limited to, the: (i) *Canadian Environmental Assessment Act;* (ii) *Canadian Environmental Protection Act*; (iii) *Transportation of Dangerous Goods Act and Regulations*; (iv) *Hazardous Product Act*; (v) *Canada Wildlife Act*; (vi) *Navigable Waters Protection Act*; (vii) *Canada National Parks Act*; (viii) *Fisheries Act;* (ix) *Canada Water Act;* (x) *National Emission Guidelines for Stationary Combustion Turbines;* (xi) *National Fire Code of Canada;* (xii) *Pest Control Products Act and Regulations;* (xiii) *PCB Regulations;* (xiv) *Canadian Species at Risk Act;* (xv) *Ozone Depleting Substances Regulations;* (xvi) *Indian Act; and* (xvii) *International Rivers Improvement Act.*

Environmental risks affecting the Corporation's utility operations include, but are not limited to: (i) hazards associated with the transportation, storage and handling of large volumes of fuel for fuel-powered electricity generating plants, including leeching of the fuel into the ground, nearby watershed areas and open waters; (ii) risk of spills or leaks of petroleum-based products, including PCB-contaminated oil, which are used in the cooling and lubrication of transformers, capacitors and other electrical equipment; (iii) risk of spills or releases into the environment arising from the improper transportation, storage, handling and disposal of other hazardous substances; (iv) GHG emissions, including natural gas and propane leaks and spills and emissions from the combustion of fuel required to generate electricity; (v) risk of fire; (vi) risk of disruption to vegetation; (vii) risk of contamination of soil and water near chemically treated poles; (viii) risk of disruption to fish, animals and their habitat as a result of the creation of artificial water flows and levels associated with hydroelectric water storage and utilization; and (ix) risk of responsibility for remediation of contaminated properties, whether or not such contamination resulted from the Corporation's utility operations.

There are many Canadian provincial and municipal laws, regulations and guidelines that address similar environmental risks as the federal laws, regulations and guidelines, but at a provincial or local level.

In British Columbia, the *Carbon Tax Act, Greenhouse Gas Reduction Targets Act, Clean Energy Act, Greenhouse Gas Reduction (Cap and Trade) Act* and anticipated cap-and-trade regulations specifically affect, or may potentially affect, the operations of the FortisBC Energy companies and FortisBC Electric.

Air emissions management is the main environmental concern of the Corporation's regulated gas utilities, primarily due to the uncertainties relating to new and emerging federal and provincial GHG laws, regulations and guidelines. While governmental policy direction is unfolding, it remains to be determined to what extent a GHG air emissions cap will impact these utilities. To help mitigate this uncertainty, the FortisBC Energy companies participate in sectoral and industry groups to monitor the development of emerging regulations. Involvement in stakeholder consultations by the FortisBC Energy companies has occurred to ensure the perspective of the Companies is considered such that unnecessary prescriptive reporting requirements do not encumber existing asset integrity management processes that are in place to address operational risks around GHG emissions.

The Government of British Columbia's Energy Plan and GHG reduction targets present risks and opportunities to the FortisBC Energy companies and, to a lesser degree, FortisBC Electric. The *Greenhouse Gas Reduction Targets Act* mandates a public sector reduction in GHG emissions of 33% from 2007 levels by 2020. This is coupled with mandates for all new electricity generation to be net carbon neutral. Energy objectives under the *Clean Energy Act* aim to ensure electricity self-sufficiency for British Columbia by 2016. The *Clean Energy Act* also places a new focus on clean demand-side management measures and smart metering technologies. In 2008 the Government of British Columbia amended the *Utilities Commission Act* to require the BCUC to ensure that utilities undertake efficiency and conservation measures in their operations and to consider the Government of British Columbia's energy objectives in specified approval processes.

The energy and GHG emissions policies in British Columbia have created incentives to expand FEI's deployment of renewable energy, such as biogas, and to expand its Energy Efficiency and Conservation Program. Additionally, the introduction of the *Carbon Tax Act* improves the competitive position of natural gas relative to other fossil fuels, as the tax is based on the amount of carbon dioxide equivalent emitted per unit of energy. Natural gas, therefore, has a lower tax rate than oil or coal products.

FEI is one of the first utility companies in Canada to include alternative energy solutions as part of its regulated energy service offerings. FEI received approval from the BCUC for a new renewable natural gas program, on a limited basis, for an initial two-year period ending in 2012. An equivalent of 10% of the subscribed customers' natural gas requirements will be sourced from local renewable energy projects feeding the gas supply network. As part of this program, FEI has received approval to activate two projects that upgrade raw biogas into biomethane, which is then added to FEI's distribution system. One of the projects is operational and has been injecting gas into FEI's distribution system since September 2010, while the other will be operational by the end of 2012. Use of biomethane will help reduce emissions from waste decomposition and will help address the Government of British Columbia's climate-change goals.

British Columbia is a participant in the Western Climate Initiative. The participants, consisting of several states and provinces, expect to implement a cap-and-trade program to reduce GHG emissions. The cap and trade program was expected to begin on January 1, 2012 but the Government of British Columbia has delayed the development of this regulatory initiative. FEI and FEVI are expected to be covered under the program. The specific details of which facilities will be covered under the program are dependent on the types of emissions and how individual facilities will be defined under cap-and-trade legislation. If implemented, the cap-and-trade program is expected to have a declining cap on emissions that all applicable facilities covered under the program must meet, either by reducing emissions internally or by purchasing allowances from other facilities for release of GHG emissions over the capped amounts.

The FortisBC Energy companies are subject to reporting and external verification requirements associated with GHG emissions under Reporting Regulations under the *Greenhouse Gas Reduction (Cap and Trade) Act* and began reporting their GHG emissions pursuant to the Reporting Regulations in 2010. Internal controls over the GHG emission reporting processes and systems have been validated in accordance with the reporting requirements to ensure the alignment of existing parameters with any additional parameters required as part of the new reporting processes. The FortisBC Energy companies have developed capabilities that will manage compliance requirements in the upcoming GHG emissions' trading environment. The companies will also continue to monitor and assess emerging regulations, in particular, the offset and allowance regulations.

The significance of GHG emissions is lower at the Corporation's Canadian regulated electric utilities because their primary business is the distribution of electricity. With respect to FortisAlberta, its operations involve only the distribution of electricity. Additionally, all in-house generating capacity at FortisBC Electric and about 70% at Newfoundland Power and most of the Corporation's non-regulated generating capacity is hydroelectric, a clean energy source. There is no coal-fired generation within any of the Corporation's operations. The Corporation's Canadian Regulated Electric Utilities are indirectly impacted, however, by GHG emissions through the purchase of power generated by suppliers using combustible fuel. Such power suppliers are responsible for compliance with carbon dioxide emissions standards and the cost of compliance with such standards is generally flowed through to end-use consumers.

The *Renewable Energy Act* (PEI) and the recent PEI Energy Accord directly impacts the long-term energy supply planning process for the province of PEI. The Act required Maritime Electric to source 15% of its annual energy sales from renewable sources by 2010, which the Company met in both 2010 and 2011. Under the PEI Energy Accord, Maritime Electric and the Government of PEI are committed to work collaboratively to increase electricity produced on PEI and sold to Maritime Electric from renewable energy sources, principally wind. The Government of PEI intends to install 30 MW of wind turbines on PEI by January 1, 2013, with a view to selling the resultant energy to Maritime Electric. Electricity generated from a 10-MW wind farm, completed on PEI in January 2012, is being purchased by the Government of PEI and, in turn, being sold to Maritime Electric.

In 2011 Canada announced its decision to invoke its legal right to formally withdraw from the Kyoto Protocol. It is uncertain as to what impact this withdrawal may have going forward.

While there are environmental laws, regulations and guidelines affecting the Corporation's operations in Grand Cayman and Turks and Caicos Islands, they are less extensive than the laws, regulations and guidelines in Canada. The United Kingdom's ratification of the United Nations Framework Convention on Climate Change and its Kyoto Protocol, however, were extended to the Cayman Islands in 2007. This framework aims to reduce GHG emissions produced by certain industries. Specific details on the regulations implementing the protocol have yet to be released by the local government of the Cayman Islands and, accordingly, Caribbean Utilities is currently unable to assess the financial impact of compliance with the framework of the protocol.

All of the energy requirements of Caribbean Utilities and Fortis Turks and Caicos are sourced from in-house diesel-powered generation. Newly installed diesel generators at Caribbean Utilities and Fortis Turks and Caicos have incorporated improvements to generate electricity in a more efficient and environmentally friendly manner. Newly installed generators have also been designed to provide an increased output per gallon consumed than the older generators. The height of exhaust stacks have been increased and improved exhaust systems installed to maximize sound attenuation, and optimize exhaust plume dispersion thereby improving local air quality in accordance with what the utilities believe to be the best industry practice. The use of diesel oil versus heavy fuel oil also results in significantly lower levels of exhaust emissions. The utilities also purchase and store diesel fuel and/or lubricating oil in bulk thereby decreasing the environmental risks associated with fuel and/or oil handling. Investments have been made in containment areas for the bulk storage of diesel fuel which have been designed to prevent the fuel from coming into contact with soil or groundwater. Caribbean Utilities also uses an underground fuel pipeline for the delivery of fuel from suppliers' distribution terminals on the coast of Grand Cayman to the day-tank holding facilities at the Company's generating plant. The pipeline eliminates the need for road transport of fuel along coastline roads.

The key focus of the utilities is to provide reliable cost-effective service with full regard for the safety of employees and the public while operating in an environmentally responsible manner. A focus on safety and the environment is, therefore, an integral and continuing component of the Corporation's operating activities.

Each of the Corporation's utilities has an EMS, with the exception of Fortis Turks and Caicos which expects to complete the implementation of its EMS in 2013. Environmental policies form the cornerstone of the EMS and outline the following commitments by each utility and its employees with respect to conducting business in a safe and environmentally responsible manner: (i) meet and comply with all applicable laws, legislation, policies, regulations and accepted standards of environmental protection; (ii) manage activities consistent with industry practice and in support of environmental policies of all levels of government; (iii) identify and manage risks to prevent or reduce adverse consequences from operations, including preventing pollution and conserving natural resources; (iv) regular environmental monitoring and audits of the EMS and striving for continual improvement in environmental performance; (v) set and review environmental objectives, targets and programs regularly; (vi) communicate openly with stakeholders including making available the utility's environmental policy and knowledge on environmental issues to customers, employees, contractors and the general public; (vii) support and participate in community-based projects that focus on the environment; (viii) provide training for employees and those working on behalf of the utility to enable them to fulfill their duties in an environmentally responsible manner; and (ix) work with industry associations, government and other stakeholders to establish standards for the environment appropriate to the utility's business.

Through an EMS, documented procedures are in place to control activities that can affect the environment. Common elements of the utilities' EMSs include: (i) regular inspections of fuel and oil-filled equipment in order to identify and correct for potential spills, and spill response systems to ensure that all spills are addressed, and the associated cleanup is conducted in a prompt and environmentally responsible manner; (ii) GHG emissions management; (iii) procedures for handling, transporting, storing and disposing of hazardous substances, including chemically treated poles, asbestos, lead and mercury, where applicable; (iv) programs to mitigate fire-related incidents; (v) programs for the management and/or elimination of PCBs, where applicable; (vi) vegetation management programs; (vii) training and communicating of environmental policies to employees to ensure work is conducted in an environmentally responsible manner; (viii) review of work practices that affect the environment; (ix) waste management programs; (x) environmental emergency response procedures; (xi) environmental site assessments; and (xii) environmental incident reporting procedures. Additionally, in the case of Newfoundland Power and FortisBC Electric, the EMSs also address water control and dam structure, as well as hydroelectric generating facility operations and the impact of such on fish and the surrounding habitat.

The FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, and FortisOntario have developed their respective EMSs consistent with the guidelines of ISO 14001, an internationally recognized standard for EMSs. Caribbean Utilities operates an EMS associated with its generation operations, which is ISO 14001 certified, and uses an EMS for its T&D operations, which is consistent with ISO 14001 guidelines. Fortis Turks and Caicos' EMS, when fully implemented, is also expected to be ISO 14001 certified. As part of their respective EMS, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor performance. External and/or internal audits of the EMSs are performed on a periodic basis. Based on audits last completed, the EMSs continue to be effective, properly implemented and maintained, and materially consistent with ISO 14001 guidelines.

Each of the Corporation's Canadian Regulated Electric Utilities that is a member of the CEA is an active participant in the CEA's Sustainable Electricity Program, which was launched in 2009. Participants in the program commit to continuous improvement of their environmental management and performance including reporting annually on environmental and other performance indicators.

In addition to the EMSs, various energy efficiency programs and initiatives, which help in reducing GHG emissions, are undertaken by the utilities or offered to customers.

Environmental risks associated with the Corporation's non-regulated generation operations are addressed in a similar manner as the Corporation's regulated electric utilities that operate in the same jurisdiction as the non-regulated generation operations.

The key environmental risks affecting the Corporation's hospitality and real estate operations include, but are not limited to: (i) asbestos and urea-formaldehyde contamination in buildings; (ii) release of ozone-depleting substances from air conditioning and refrigeration equipment; (iii) fuel tank leaks; and (iv) remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. Fortis Properties is committed to meeting the requirements of environmental standards related to its hospitality and real estate operations. In assessing properties being acquired, all must meet environmental standards, including, but not limited to, the appropriate federal, provincial and municipal standards for asbestos, fuel storage, urea-formaldehyde and chlorofluorocarbon-based refrigerants in air conditioning and refrigeration equipment. This process is also applied to existing properties, ensuring environmental compliance by all facilities.

The Corporation has asset-retirement obligations as disclosed in the notes to its 2011 Audited Consolidated Financial Statements. However, liabilities with respect to these asset-retirement obligations have not been recorded in the Corporation's 2011 Audited Consolidated Financial Statements, with the exception of approximately $4 million related to PCBs at FortisBC Electric, as they could not be reasonably estimated or were determined to be immaterial (including asset-retirement obligations associated with asbestos and chemically treated poles) to the Corporation's consolidated results of operations, cash flows or financial position. The utilities have ongoing programs to identify and replace transformers which are at risk of spillage of oil, and PCBs continue to be removed from service and safely disposed of in compliance with applicable laws and regulations.

Costs associated with environmental protection initiatives (including the development, implementation and maintenance of EMSs), compliance with environmental laws, regulations and guidelines, and environmental damage did not materially affect the Corporation's consolidated results of operations, cash flows or financial position during 2011 and, based on current laws, facts and circumstances, are not expected to have a material effect in 2012. Many of the above costs, however, are embedded in the utilities' operating, maintenance and capital programs and are, therefore, not readily identifiable. At the Corporation's regulated utilities, prudently incurred operating and capital costs associated with environmental protection initiatives, compliance with environmental laws, regulations and guidelines, and environmental damage are eligible for recovery in customer rates. Fortis believes that the Corporation and its subsidiaries are materially compliant with environmental laws and regulations applicable to them in the various jurisdictions in which they operate.

Oversight of environmental matters is performed at the subsidiary level with regular reporting of environmental matters to the respective subsidiary's Board of Directors.

For further information on the Corporation's environmental risk factors, refer to the "Business Risk Management - Environmental Risks" section of the Corporation's MD&A.

6.0 RISK FACTORS

For information with respect to the Corporation's significant business risks, refer to the "Business Risk Management" section of the Corporation's MD&A.

7.0 GENERAL DESCRIPTION OF SHARE CAPITAL STRUCTURE

The authorized share capital of the Corporation consists of the following:

(a) an unlimited number of Common Shares without nominal or par value;
(b) an unlimited number of First Preference Shares without nominal or par value; and
(c) an unlimited number of Second Preference Shares without nominal or par value.

As at March 14, 2012, the following Common Shares and First Preference Shares were issued and outstanding.

Share Capital	Issued and Outstanding	Votes per Share
Common Shares	189,260,794	One
First Preference Shares, Series C	5,000,000	None
First Preference Shares, Series E	7,993,500	None
First Preference Shares, Series F	5,000,000	None
First Preference Shares, Series G	9,200,000	None
First Preference Shares, Series H	10,000,000	None

The following table summarizes the cash dividends declared per share for each of the Corporation's class of share for the past three years.

	Dividends Declared *(per share)*		
Share Capital	**2009** [(1)]	**2010** [(1)]	**2011**
Common Shares	$0.78	$1.41	$1.17
First Preference Shares, Series C	$1.0219	$1.7031	$1.3625
First Preference Shares, Series E	$0.9188	$1.5313	$1.2250
First Preference Shares, Series F	$0.9188	$1.5313	$1.2250
First Preference Shares, Series G	$0.9844	$1.6406	$1.3125
First Preference Shares, Series H [(2)]	-	$1.1636	$1.0625

(1) *First quarter 2010 dividends were declared in January 2010 resulting in three quarters of dividends declared in 2009 and five quarters of dividends declared in 2010*

(2) *A total of 10 million Five-Year Fixed Rate Reset First Preference Shares, Series H were issued on January 26, 2010 at $25.00 per share for net after-tax proceeds of $242 million, which are entitled to receive cumulative dividends in the amount of $1.0625 per share per annum for the first five years.*

For purposes of the enhanced dividend tax credit rules contained in the Income Tax Act (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on Common and Preferred Shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

On December 13, 2011, the Board declared an increase in the quarterly Common Share dividend to $0.30 per share from $0.29 per share, with the first payment made on March 1, 2012, to holders of record as of February 15, 2012. Also on December 13, 2011, the Board declared a first quarter 2012 dividend on the First Preference Shares, Series C, E, F, G and H in accordance with the applicable annual prescribed rate and was paid on March 1, 2012 to holders of record as of February 15, 2012.

On March 13, 2012, the Board declared a second quarter 2012 dividend of $0.30 per Common Share and a second quarter 2012 dividend on the First Preference Shares, Series C, E, F, G and H in accordance with the applicable annual prescribed rate. In each case, the second quarter 2012 dividends will be paid on June 1, 2012 to holders of record as of May 17, 2012.

Common Shares

Dividends on Common Shares are declared at the discretion of the Board. Holders of Common Shares are entitled to dividends on a pro rata basis if, as, and when declared by the Board. Subject to the rights of the holders of the First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive dividends in priority to or rateably with the holders of the Common Shares, the Board may declare dividends on the Common Shares to the exclusion of any other class of shares of the Corporation.

On the liquidation, dissolution or winding-up of Fortis, holders of Common Shares are entitled to participate rateably in any distribution of assets of Fortis, subject to the rights of holders of First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or rateably with the holders of the Common Shares.

Holders of the Common Shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Fortis, other than separate meetings of holders of any other class or series of shares, and are entitled to one vote in respect of each Common Share held at such meetings.

First Preference Shares, Series C

The 5,000,000 First Preference Shares, Series C are entitled to fixed cumulative preferential cash dividends at a rate of $1.3625 per share per annum. On or after June 1, 2011, the Corporation may, at its option, redeem for cash the First Preference Shares, Series C, in whole at any time, or in part from time to time, at $25.50 per share if redeemed before June 1, 2012; at $25.25 per share if redeemed on or after June 1, 2012 but before June 1, 2013; and at $25.00 per share if redeemed on or after June 1, 2013 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. On or after June 1, 2010, the Corporation may, at its option, convert all, or from time to time, any part of the outstanding First Preference Shares, Series C into fully paid and freely tradeable Common Shares of the Corporation. The number of Common Shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per Preference Share, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares. On or after September 1, 2013, each First Preference Share, Series C will be convertible at the option of the holder on the first day of September, December, March and June of each year into freely tradeable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares. If a holder of First Preference Shares, Series C elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference Shares, Series C for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series E

The 7,993,500 First Preference Shares, Series E are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. On or after June 1, 2013, the Corporation may, at its option, redeem all, or from time to time any part of, the outstanding First Preference Shares, Series E by the payment in cash of a sum per redeemed share equal to $25.75 if redeemed during the 12 months commencing June 1, 2013; $25.50 if redeemed during the 12 months commencing June 1, 2014; $25.25 if redeemed during the 12 months commencing June 1, 2015; and $25.00 if redeemed on or after June 1, 2016 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. On or after June 1, 2013, the Corporation may, at its option, convert all, or from time to time any part of the outstanding First Preference Shares, Series E into fully paid and freely tradeable Common Shares of the Corporation.

The number of Common Shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per First Preference Share, Series E, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares at such time. On or after September 1, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first business day of September, December, March and June of each year, into fully paid and freely tradeable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares. If a holder of First Preference Shares, Series E elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference, Shares E for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series F

The 5,000,000 First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. On or after December 1, 2011, the Corporation may, at its option, redeem for cash the First Preference Shares, Series F, in whole at any time or in part from time to time, at $26.00 per share if redeemed before December 1, 2012; at $25.75 per share if redeemed on or after December 1, 2012 but before December 1, 2013; at $25.50 per share if redeemed on or after December 1, 2013 but before December 1, 2014; at $25.25 per share if redeemed on or after December 1, 2014 but before December 1, 2015; and at $25.00 per share if redeemed on or after December 1, 2015 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series G

The 9,200,000 First Preference Shares, Series G are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.3125 per share per annum for each year up to and including August 31, 2013. For each five-year period after that date, the holders of First Preference Shares, Series G are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying the $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13%. On September 1, 2013, and on September 1 every five years thereafter, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series G, in whole at any time, or in part from time to time, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series H

The 10,000,000 First Preference Shares, Series H are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.0625 per share per annum for each year up to but excluding June 1, 2015. For each five-year period after that date, the holders of First Preference Shares, Series H are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 1.45%.

On each Series H Conversion Date, being June 1, 2015, and June 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series H, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series H Conversion Date, the holders of First Preference Shares, Series H, have the option to convert any or all of their First Preference Shares, Series H into an equal number of cumulative redeemable floating rate First Preference Shares, Series I.

The holders of First Preference Shares, Series I will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada Treasury Bills plus 1.45%.

On each Series I Conversion Date, being June 1, 2020, and June 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On any date after June 1, 2015, that is not a Series I Conversion Date, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series I Conversion Date, the holders of First Preference Shares, Series I, have the option to convert any or all of their First Preference Shares, Series I into an equal number of First Preference Shares, Series H.

On any Series H Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series H outstanding, such remaining First Preference Shares, Series H will automatically be converted into an equal number of First Preference Shares, Series I. On any Series I Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series I outstanding, such remaining First Preference Shares, Series I will automatically be converted into an equal number of First Preference Shares, Series H. However, if such automatic conversions would result in less than 1,000,000 Series I First Preference Shares or less than 1,000,000 Series H First Preference Shares outstanding then no automatic conversion would take place.

Convertible Debentures

The Corporation's US$40 million Unsecured Subordinated Convertible Debentures were converted, at the option of the holder, into 1.4 million common shares of Fortis at $29.63 (US$29.11) per share in November 2011, as permitted under the debt agreement.

Debt Covenant Restrictions on Dividend Distributions

The Trust Indenture pertaining to the Corporation's $200 million Senior Unsecured Debentures contains a covenant which provides that Fortis shall not declare or pay any dividends (other than stock dividends or cumulative preferred dividends on preferred shares not issued as stock dividends) or make any other distribution on its shares or redeem any of its shares or prepay Subordinated Debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

The Corporation has an $800 million unsecured committed revolving credit facility, maturing in July 2015, that can be used for general corporate purposes, including acquisitions. At any time prior to maturity, the Corporation may provide written notice to increase the amount available under the facility to $1 billion. The credit facility contains a covenant which provides that Fortis shall not declare or pay any dividends or make any other restricted payments if, immediately thereafter, consolidated debt to consolidated capitalization ratio would exceed 70% at any time.

As at December 31, 2011 and 2010, the Corporation was in compliance with its debt covenant restrictions pertaining to dividend distributions, as described above.

8.0 CREDIT RATINGS

Securities issued by Fortis and its utilities, that are currently rated, are rated by one or more credit rating agencies, namely, DBRS, S&P and/or Moody's. The ratings assigned to securities issued by Fortis and its utilities are reviewed by the agencies on an ongoing basis. Credit ratings and stability ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are not recommendations to buy, sell or hold securities. Ratings may be subject to revision or withdrawal at any time by the rating organization. The following table summarizes the Corporation's credit ratings as at March 15, 2012.

Fortis Credit Ratings

Company	DBRS	S&P	Moody's
Fortis	A (low), under review – developing (unsecured debt)	A-, watch negative (unsecured debt)	N/A
FHI	BBB (high), stable (unsecured debt)	N/A	Baa2, stable (unsecured debt)
FEI	A, stable (secured & unsecured debt)	N/A	A3, stable (unsecured debt)
FEVI	N/A	N/A	A3, stable (unsecured debt)
FortisAlberta	A (low), stable (senior unsecured debt)	A-, watch negative (senior unsecured debt)	Baa1, stable (senior unsecured debt)
FortisBC Electric	A (low), stable (senior & unsecured debt)	N/A	Baa1, stable (unsecured debt)
Newfoundland Power	A, stable (first mortgage bonds)	N/A	A2, stable (first mortgage bonds)
Maritime Electric	N/A	A-, stable (senior secured debt)	N/A
Caribbean Utilities	A (low), stable (senior unsecured debt)	A-, stable (senior unsecured debt)	N/A

In February 2012 DBRS placed the Corporation's credit rating under review with developing implications and S&P placed the Corporation's credit rating under credit watch with negative implications following the CH Energy Group acquisition announcement by Fortis. S&P also placed FortisAlberta's credit rating on credit watch with negative implications due to the credit watch placement on Fortis. Refer also to "Proposed Acquisition" heading in Section 2.2 of this 2011 Annual Information Form.

DBRS rates debt instruments by rating categories ranging from AAA to D, which represents the range from highest to lowest quality of such securities. DBRS states that: (i) 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; (ii) its 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; and (iii) every rating is based on quantitative and qualitative considerations that are relevant for the borrowing entity. According to DBRS, a rating of A by DBRS is in the middle of three subcategories within the third highest of nine major categories. Such rating is assigned to debt instruments considered to be of satisfactory credit quality and for which protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. Entities in the BBB category are considered to have long-term debt 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. The assignment of a (high) or (low) modifier within each rating category indicates relative standing within such category.

S&P long-term debt ratings are on a ratings scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities. S&P uses '+' or '-' designations to indicate the relative standing of securities within a particular rating category. S&P states that its credit ratings are current opinions of the financial security characteristics with respect to the ability to pay under contracts in accordance with their terms. This opinion is not specific to any particular contract, nor does it address the suitability of a particular contract for a specific purpose or purchaser. An issuer rated A is regarded as having financial security characteristics to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than those in higher-rated categories.

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 states that its long-term debt ratings are opinions of relative risk of fixed-income obligations with an original maturity of one year or more and that 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 and such a debt rating is assigned to debt instruments considered to be of medium-grade quality. Debt instruments rated Baa are subject to moderate credit risk and may possess certain speculative characteristics. Debt instruments rated A are considered upper-medium grade and are subject to low credit risk.

9.0 MARKET FOR SECURITIES

The Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; and First Preference Shares, Series H of Fortis are listed on the Toronto Stock Exchange under the symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F, FTS.PR.G and FTS.PR.H, respectively.

The following table sets forth the reported high and low trading prices and trading volumes for the Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; and First Preference Shares, Series H on a monthly basis for the year ended December 31, 2011.

Fortis 2011 Trading Prices and Volumes						
	Common Shares			First Preference Shares, Series C		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	34.74	33.30	7,432,455	26.89	26.05	161,956
February	35.45	32.30	9,925,791	26.10	25.60	329,057
March	33.59	31.53	10,482,063	25.85	25.63	81,458
April	33.28	31.05	5,367,214	26.33	26.00	71,764
May	33.85	31.98	15,795,186	26.19	25.54	463,532
June	33.05	30.79	9,954,946	26.04	25.75	348,223
July	32.85	31.53	5,183,546	26.49	25.85	80,991
August	32.75	28.24	14,509,526	26.45	25.86	34,748
September	33.78	31.44	11,207,968	26.14	25.55	135,005
October	34.39	31.32	7,950,203	26.26	25.60	75,014
November	34.16	31.32	18,591,643	26.45	25.75	123,447
December	33.62	31.97	9,940,675	26.21	25.65	187,813
	First Preference Shares, Series E			First Preference Shares, Series F		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	27.59	26.75	163,482	23.50	22.76	66,772
February	26.87	26.31	236,757	23.75	22.61	59,272
March	27.00	26.21	36,423	23.88	22.90	87,710
April	27.07	26.45	29,389	23.81	23.00	44,696
May	27.34	26.74	272,521	24.00	23.05	87,756
June	27.24	26.61	143,830	24.25	23.16	74,591
July	27.53	26.80	16,908	24.79	24.01	46,339
August	27.86	26.51	367,951	25.10	23.68	67,083
September	27.00	26.59	60,562	25.00	24.33	52,951
October	27.22	26.50	126,929	26.24	24.50	96,924
November	28.12	27.11	114,823	25.69	24.92	56,811
December	27.45	26.98	28,011	26.41	24.98	39,355
	First Preference Shares, Series G			First Preference Shares, Series H		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	26.62	25.95	51,868	25.90	25.25	192,555
February	26.49	25.53	57,289	25.91	25.25	96,073
March	26.57	25.56	110,302	25.73	24.97	163,231
April	26.58	26.25	94,098	25.52	25.05	101,246
May	26.50	25.88	97,923	26.50	25.14	96,623
June	26.99	25.88	128,971	25.96	25.25	251,857
July	26.30	25.81	68,285	25.95	25.21	67,873
August	26.40	25.34	75,920	26.00	25.14	156,853
September	26.30	25.58	110,543	26.05	25.00	94,461
October	26.58	25.80	69,175	26.00	25.10	48,926
November	26.19	25.43	107,174	25.84	25.10	95,476
December	26.65	25.70	40,271	26.00	25.29	210,693

10.0 DIRECTORS AND OFFICERS

The Board adopted a new director tenure policy in September 2010 and it is to be reviewed on a periodic basis. The tenure policy provides that Directors of the Corporation are to be elected for a term of one year and, except in appropriate circumstances determined by the Board, be eligible for re-election until the Annual Meeting of Shareholders next following the date on which they achieve age 70 or the 12th anniversary of their initial election to the Board. The policy does not apply to Mr. Marshall whose service on the Board is related to his tenure as CEO. The following chart sets out the name and municipality of residence of each of the Directors of Fortis and indicates their principal occupations within five preceding years.

Fortis Directors	
Name	**Principal Occupations Within Five Preceding Years**
PETER E. CASE *(1)* Kingston, Ontario	Mr. Case, 57, a Corporate Director, retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets after 17 years as a utility and pipeline analyst. Mr. Case was then a consultant to the utility industry and its regulators for three years. Prior to his position at CIBC, he was Managing Director at BMO Nesbitt Burns. He was awarded a Bachelor of Arts and a Master of Business Administration from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto. Mr. Case was first elected to the Board in May 2005 and has been Chair of the Audit Committee of the Board since March 2011. Mr. Case was a Director of FortisOntario from 2003 to 2010 and served as Chair of the FortisOntario Board from 2009 to 2010. He does not serve as a director of any other reporting issuer.
FRANK J. CROTHERS *(2)* Nassau, Bahamas	Mr. Crothers, 67, is Chairman and Chief Executive Officer of Island Corporate Holdings Limited, Nassau, Bahamas. For more than 35 years, he has served on many public and private sector boards. For more than a decade he was on the Board of Harvard University Graduate School of Education and also served a three-year term as Chairman of CARILEC, the Caribbean Association of Electrical Utilities. Mr. Crothers is the past President of FortisTCI Limited (formerly P.P.C. Limited), which was acquired by the Corporation in August 2006. He serves as non-executive Vice Chair of the Board of Caribbean Utilities. Mr. Crothers was first elected to the Fortis Board in May 2007. He was previously a director of Belize Electricity from 2007 to 2010. Mr. Crothers is also a director of reporting issuers Templeton Mutual Funds, Talon Metals Corp. and AML Limited.
IDA J. GOODREAU *(3)* Vancouver, British Columbia	Ms. Goodreau, 60, is an Adjunct Professor at Sauder School of Business and Director of Strategy, Center for Healthcare Management, University of British Columbia. She is the past President and Chief Executive Officer of LifeLabs. Prior to joining LifeLabs in March 2009, she was President and Chief Executive Officer of the Vancouver Coastal Health Authority since 2002. Ms. Goodreau has held senior leadership roles in several Canadian and international pulp and paper and natural gas companies prior to entering the health care field. She was awarded a Master of Business Administration and a Bachelor of Commerce, Honors, degree from the University of Windsor and a Bachelor of Arts, (English and Economics) from the University of Western Ontario. Ms. Goodreau was first elected to the Board in May 2009. She has served on numerous private and public sector boards and has been a director of FHI and FortisBC Inc. since 2007 and 2010, respectively. Ms. Goodreau does not serve as a director of any other reporting issuer.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
DOUGLAS J. HAUGHEY *(1)* Calgary, Alberta	Mr. Haughey, 55, is President and Chief Executive Officer of Provident Energy Ltd., an owner/operator of natural gas liquids midstream services and marketing. From 1999 through 2008, Mr. Haughey held several executive roles with Spectra Energy and predecessor companies. He had overall responsibility for its western Canadian natural gas midstream business, was President and Chief Executive Officer of Spectra Energy Income Fund and also led Spectra's strategic development and mergers and acquisitions teams based in Houston, Texas. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with a Master of Business Administration. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors. He was first elected to the Board in May 2009. Mr. Haughey became a director of FortisAlberta in 2010 and is currently a director of Provident Energy Ltd.
H. STANLEY MARSHALL Paradise, Newfoundland and Labrador	Mr. Marshall, 61, is President and Chief Executive Officer of the Corporation. He joined Newfoundland Power in 1979 and was appointed President and Chief Executive Officer of Fortis in 1996. Mr. Marshall graduated from the University of Waterloo with a Bachelor of Applied Science (Chem. Eng.) and Dalhousie University with a Bachelor of Laws. He is a member of the Law Society of Newfoundland and Labrador and a Registered Professional Engineer in the Province of Newfoundland and Labrador. Mr. Marshall was first elected to the Board in October 1995. He serves on the boards of all Fortis utilities in British Columbia, Ontario and the Caribbean and the Board of Fortis Properties Corporation. He is also a director of Enerflex Ltd.
JOHN S. McCALLUM *(1) (2)* Winnipeg, Manitoba	Mr. McCallum, 68, has been a Professor of Finance at the University of Manitoba since July 1973. He served as Chairman of Manitoba Hydro from 1991 to 2000 and as Policy Advisor to the Federal Minister of Finance from 1984 to 1991. Mr. McCallum graduated from the University of Montreal with a Bachelor of Arts (Economics) and a Bachelor of Science (Mathematics). He was awarded a Master of Business Administration from Queen's University and a PhD in Finance from the University of Toronto. Mr. McCallum was first elected to the Board in July 2001 and was appointed Chair of the Governance and Nominating Committee of the Corporation in May 2005. He was previously a director of FortisBC Inc. and FortisAlberta from 2004 to 2010 and from 2005 to 2010, respectively. Mr. McCallum also serves as a director of IGM Financial Inc. and Toromont Industries Ltd.
HARRY McWATTERS *(2)* Summerland, British Columbia	Mr. McWatters, 66, is the founder and past President of Sumac Ridge Estate Wine Group, a leader in the British Columbia wine industry. He is President of Vintage Consulting Group Inc., Harry McWatters Inc., Okanagan Wine Academy and Black Sage Vineyards Ltd., all of which are engaged in various aspects of the British Columbia wine industry. Mr. McWatters was first elected to the Board in May 2007. He was elected to the Board of FortisBC Inc. in September 2005 and served as Chair of that Company's Board from 2006 through 2010. Mr. McWatters became a director of FHI in November 2007 and does not serve as a director of any other reporting issuer.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
RONALD D. MUNKLEY (2) (3) Mississauga, Ontario	Mr. Munkley, 65, a Corporate Director, retired in April 2009 as Vice Chairman and Head of the Power and Utility Business of CIBC World Markets. Mr. Munkley had acted as an advisor on most Canadian utility transactions since joining CIBC World Markets in 1998. Prior to that, he was employed at Enbridge Consumers Gas for 27 years, culminating as Chairman, President and Chief Executive Officer. Mr. Munkley led Enbridge Consumers Gas through deregulation and restructuring in the 1990s. He graduated from Queen's University with a Bachelor of Science, Honors (Engineering). Mr. Munkley is a professional engineer and has completed the Executive and Senior Executive Programs of the University of Western Ontario and the Partners, Directors and Senior Officers Certificate of the Canadian Securities Institute. He was first elected to the Board in May 2009. Mr. Munkley also serves as a director of Bird Construction Inc.
DAVID G. NORRIS (1) (2) (3) St. John's, Newfoundland and Labrador	Mr. Norris, 64, a Corporate Director, has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited. Previously, he held Deputy Minister positions with the Department of Finance and Treasury Board, Government of Newfoundland and Labrador. Mr. Norris graduated with a Bachelor of Commerce from Memorial University of Newfoundland and a Master of Business Administration from McMaster University. He was first elected to the Board in May 2005 and was appointed Chair of the Board in December 2010. He served as Chair of the Audit Committee of the Board from May 2006 through March 2011. Mr. Norris was a director of Newfoundland Power from 2003 through 2010 and served as Chair of Newfoundland Power's Board from 2006 through 2010. He served as a director of Fortis Properties from 2006 through 2010. Mr. Norris does not serve as a director of any other reporting issuer.
MICHAEL A. PAVEY (1) (3) Moncton, New Brunswick	Mr. Pavey, 64, a Corporate Director, retired as Executive Vice-President and Chief Financial Officer of Major Drilling Group International Inc. in September 2006. Prior to joining Major Drilling Group International Inc. in 1999, he held senior regulatory and financial executive positions with TransAlta Corporation. Mr. Pavey graduated from the University of Waterloo with a Bachelor of Applied Science (Mechanical Engineering) and from McGill University with a Master of Business Administration. He retired from the Board of Maritime Electric in February 2007 after a six-year term, which included service as Chair of that Company's Audit and Environment Committee from 2003 through 2007. Mr. Pavey was first elected to the Board in May 2004. He does not serve as a director of any other reporting issuer.
ROY P. RIDEOUT (2) (3) Halifax, Nova Scotia	Mr. Rideout, 64, a Corporate Director, retired as Chairman and Chief Executive Officer of Clarke Inc. in October 2002. Prior to 1998, he served as President of Newfoundland Capital Corporation Limited and held senior executive positions in the Canadian airline industry. Mr. Rideout graduated with a Bachelor of Commerce from Memorial University of Newfoundland and obtained designation as a Chartered Accountant. Mr. Rideout was first elected to the Board in March 2001. He is the Chair of the Human Resources Committee of the Board and has held that position since May 2003. Mr. Rideout also serves as a director of NAV CANADA.

(1) *Serves on the Audit Committee*
(2) *Serves on the Governance and Nominating Committee*
(3) *Serves on the Human Resources Committee*

The following table sets out the name and municipality of residence of each of the officers of Fortis and indicates the office held.

Fortis Officers	
Name and Municipality of Residence	**Office Held**
H. Stanley Marshall Paradise, Newfoundland and Labrador	President and Chief Executive Officer [(1)]
Barry V. Perry Mount Pearl, Newfoundland and Labrador	Vice President, Finance and Chief Financial Officer [(2)]
Ronald W. McCabe St. John's, Newfoundland and Labrador	Vice President, General Counsel and Corporate Secretary [(3)]
Donna G. Hynes St. John's, Newfoundland and Labrador	Assistant Secretary [(4)]

(1) Mr. Marshall was appointed President and Chief Operating Officer, effective October 1, 1995. Effective May 1, 1996, Mr. Marshall became Chief Executive Officer.

(2) Mr. Perry was appointed Vice President, Finance and Chief Financial Officer, effective January 1, 2004. Prior to that time, Mr. Perry was Vice President, Finance and Chief Financial Officer of Newfoundland Power.

(3) Mr. McCabe was appointed General Counsel and Corporate Secretary, effective January 1, 1997. Effective May 6, 2008, Mr. McCabe became Vice President, General Counsel and Corporate Secretary.

(4) Ms. Hynes was appointed Assistant Secretary, effective December 8, 1999. She joined Fortis as Manager, Investor and Public Relations in October 1999 and, prior to that time, was employed by Newfoundland Power.

As at December 31, 2011, the directors and officers of Fortis, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 717,472 Common Shares, representing 0.4% of the issued and outstanding Common Shares of Fortis. The Common Shares are the only voting securities of the Corporation.

11.0 AUDIT COMMITTEE

11.1 Education and Experience

The education and experience of each Audit Committee Member that is relevant to such Member's responsibilities as a Member of the Audit Committee are set out below. As at December 31, 2011, the Audit Committee was composed of the following persons.

Fortis Audit Committee	
Name	**Relevant Education and Experience**
PETER E. CASE *(Chair)* Kingston, Ontario	Mr. Case retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. He was awarded a Bachelor of Arts and a Master of Business Administration from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto.
DOUGLAS J. HAUGHEY Calgary, Alberta	Mr. Haughey is President and Chief Executive Officer of Provident Energy Ltd. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with a Master of Business Administration. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors.
JOHN S. McCALLUM Winnipeg, Manitoba	Mr. McCallum is a Professor of Finance at the University of Manitoba. He graduated from the University of Montreal with a Bachelor of Arts (Economics) and a Bachelor of Science (Mathematics). Mr. McCallum was awarded a Master of Business Administration from Queen's University and a PhD in Finance from the University of Toronto.
DAVID G. NORRIS **St. John's, Newfoundland and Labrador**	Mr. Norris has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited. He graduated with a Bachelor of Commerce from Memorial University of Newfoundland and a Master of Business Administration from McMaster University.
MICHAEL A. PAVEY **Moncton, New Brunswick**	Mr. Pavey retired as Executive Vice President and Chief Financial Officer of Major Drilling Group International Inc. in September 2006. Prior to joining Major Drilling Group International Inc. in 1999, he held senior regulatory and financial executive positions with TransAlta Corporation. Mr. Pavey graduated from University of Waterloo with a Bachelor of Applied Science (Mechanical Engineering) and from McGill University with a Master of Business Administration.

The Board has determined that each of the Audit Committee Members is independent and financially literate. Independent means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110 - *Audit Committees*. Financially literate means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be raised by the Corporation's consolidated financial statements.

11.2 Audit Committee Mandate

The text of the Corporation's Audit Committee Mandate is detailed below.

A. Objective

The Committee shall provide assistance to the Board by overseeing the external audit of the Corporation's annual financial statements and the accounting and financial reporting and disclosure processes and policies of the Corporation.

B. Definitions

In this mandate:

"AIF" means the Annual Information Form filed by the Corporation;

"Committee" means the Audit Committee appointed by the Board pursuant to this mandate;

"Board" means the board of directors of the Corporation;

"CICA" means the Canadian Institute of Chartered Accountants or any successor body;

"Corporation" means Fortis Inc.;

"**Director"** means a member of the Board;

"Financially Literate" means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be present in the Corporation's financial statements;

"External Auditor" means the firm of chartered accountants, registered with the Canadian Public Accountability Board or its successor, and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

"Independent" means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110;

"Internal Auditor" means the person employed or engaged by the Corporation to perform the internal audit function of the Corporation;

"Management" means the senior officers of the Corporation;

"MD&A" means the Corporation's management discussion and analysis prepared in accordance with National Instrument 51-102F1 in respect of the Corporation's annual and interim financial statements; and

"Member" means a Director appointed to the Committee.

C. Composition and Meetings

1. The Committee shall be appointed annually by the Board and shall be comprised of three (3) or more Directors, each of whom is Independent and Financially Literate and none of whom is a member of Management or an employee of the Corporation or of any affiliate of the Corporation.

2. The Board shall appoint a Chair of the Committee on the recommendation of the Corporation's Governance and Nominating Committee, or such other committee as the Board may authorize.

3. The Committee shall meet at least four (4) times each year and shall meet at such other times during the year as it deems appropriate. Meetings of the Committee shall be held at the call (i) of the Chair of the Committee, or (ii) of any two (2) Members, or (iii) of the External Auditor.

4. The President and Chief Executive Officer, the Vice President, Finance and Chief Financial Officer, the External Auditor and the Internal Auditor, shall receive notice of, and (unless otherwise determined by the Chair of the Committee) shall attend all meetings of the Committee.

5. A quorum at any meeting of the Committee shall be three (3) Members.

6. The Chair of the Committee shall act as chair of all meetings of the Committee at which the Chair is present. In the absence of the Chair from any meeting of the Committee, the Members present at the meeting shall appoint one of their Members to act as Chair of the meeting.

7. Unless otherwise determined by the Chair of the Committee, the Secretary of the Corporation shall act as secretary of all meetings of the Committee.

D. Oversight of the External Audit and the Accounting and Financial Reporting and Disclosure Processes and Policies

The primary purpose of the Committee is oversight of the Corporation's external audit and the accounting and financial reporting and disclosure processes and policies on behalf of the Board. Management of the Corporation is responsible for the selection, implementation and maintenance of appropriate accounting and financial reporting principles and policies and internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations. Management is responsible for the preparation and integrity of the financial statements of the Corporation.

1. Oversight of the External Audit

The oversight of the external audit pertains to the audit of the Corporation's annual financial statements.

1.1. The Committee is responsible for the evaluation and recommendation of the External Auditor to be proposed by the Board for appointment by the shareholders.

1.2. In advance of each audit, the Committee shall review the External Auditor's audit plan including the general approach, scope and areas subject to risk of material misstatement.

1.3. The Committee is responsible for approving the terms of engagement and fees of the External Auditor.

1.4. The Committee shall review and discuss the Corporation's annual audited financial statements, together with the External Auditor's report thereon, and MD&A with Management and the External Auditor to gain reasonable assurance as to the accuracy, consistency and completeness thereof. The Committee shall meet privately with the External Auditor. The Committee shall oversee the work of the

External Auditor and resolve any disagreements between Management and the External Auditor.

1.5. The Committee shall use reasonable efforts, including discussion with the External Auditor, to satisfy itself as to the External Auditor's independence as defined in Canadian Auditing Standard – 260.

2. Oversight of the Accounting and Financial Reporting and Disclosure Processes

2.1. The Committee shall recommend the annual audited financial statements together with the MD&A for approval by the Board.

2.2. The Committee shall review the interim unaudited financial statements with the External Auditor and Management, together with the External Auditor's review engagement report thereon.

2.3. The Committee shall review and approve publication of the interim unaudited financial statements together with notes thereto, the interim MD&A and earnings media release on behalf of the Board.

2.4. The Committee shall review and recommend approval by the Board of the Corporation's AIF, Management Information Circular, any prospectus and other financial information or disclosure documents to be issued by the Corporation prior to their public release.

2.5. The Committee shall use reasonable efforts to satisfy itself as to the integrity of the Corporation's financial information systems, internal control over financial reporting and the competence of the Corporation's accounting personnel and senior financial management responsible for accounting and financial reporting.

2.6. The Committee shall be responsible for the oversight of the Internal Auditor.

2.7. The Committee shall monitor and report on the development of the Enterprise Risk Management Program.

3. Oversight of the Audit Committee Mandate and Policies

On a periodic basis, the Committee shall review and report to the Board on the Audit Committee Mandate as well as on the following policies:

3.1. Reporting Allegations of Suspected Improper Conduct and Wrongdoing Policy;

3.2. Derivative Financial Instruments and Hedging Policy;

3.3. Pre-Approval of Audit and Non-Audit Services Policy;

3.4. Hiring of Employees from Independent Auditing Firms Policy;

3.5. The Internal Audit Role and Function Policy; and

3.6. any other policies that may be established, from time to time, relating to accounting and financial reporting and disclosure processes; oversight of the external audit of the Corporation's financial statements; and oversight of the internal audit function.

E. Reporting

The Chair of the Committee, or another designated Member, shall report to the Board at each regular meeting on those matters which were dealt with by the Committee since the last regular meeting of the Board.

F. Other

1. The Committee shall perform such other functions as may, from time to time, be assigned to the Committee by the Board.

2. The Committee may approve, in circumstances that it considers appropriate, the engagement by the Committee or any Director of outside advisors or persons having special expertise at the expense of the Corporation.

11.3 Pre-Approval Policies and Procedures

The Audit Committee has established a policy which requires pre-approval of all audit and non-audit services provided to the Corporation and its subsidiaries by the Corporation's External Auditor. The Pre-Approval of Audit and Non-Audit Services Policy describes the services which may be contracted from the External Auditor and the limitations and authorization procedures related thereto. This policy defines services such as bookkeeping, valuations, internal audit and management functions which may not be contracted from the External Auditor and establishes an annual limit for permissible non-audit services not greater than the total fee for audit services. Audit Committee pre-approval is required for all audit and non-audit services.

11.4 External Auditor Service Fees

Fees incurred by the Corporation for work performed by Ernst & Young LLP, the Corporation's External Auditors, during each of the last two fiscal years for audit, audit-related and tax, and non-audit services were as follows:

Fortis
External Auditor Services Fees
($ thousands)

Ernst & Young LLP	**2011**	2010
Audit Fees [(1) (2)]	**2,518**	2,535
Audit-Related Fees [(2)]	**1,146**	775
Tax Fees	**153**	202
Non-Audit Services	**145**	-
Total	**3,962**	3,512

(1) *Relate to financial statements prepared in accordance with Canadian GAAP*
(2) *The 2010 audit and audit-related fees have been reclassified to conform with the current year's presentation.*

Audit-related fees increased year over year primarily due to work performed by Ernst & Young LLP in preparation for the Corporation's conversion to US GAAP, effective January 1, 2012, including audits and reviews performed on the Corporation's 2011 annual and quarterly consolidated financial statements, respectively, with 2010 comparatives, prepared in accordance with US GAAP. Non-audit services related to work performed at Caribbean Utilities during 2011 associated with the Company's insurance claim related to a damaged generating unit. The non-audit fees were pre-approved by Caribbean Utilities' Audit Committee and do not impair the independence of Ernst & Young LLP.

12.0 TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares and First Preference Shares of Fortis is Computershare Trust Company of Canada in Halifax, Montréal and Toronto.

Computershare Trust Company of Canada
9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.computershare.com/fortisinc

13.0 AUDITORS

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants, The Fortis Building, 7th Floor, 139 Water Street, St. John's, NL, A1C 1B2. The financial statements of the Corporation for the fiscal year ended December 31, 2011 have been audited by Ernst & Young LLP. Ernst & Young LLP report that they are independent of the Corporation in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Newfoundland.

14.0 ADDITIONAL INFORMATION

Reference is made to the MD&A and 2011 Audited Consolidated Financial Statements on pages 8 through 77 and pages 78 through 133, respectively, of the 2011 Fortis Inc. Annual Report to Shareholders, which pages are incorporated herein by reference. Additional information relating to the Corporation can be found on SEDAR at www.sedar.com.

Further additional information, including officers' and directors' remuneration and indebtedness, principal holders of the securities of Fortis, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in the Management Information Circular of Fortis dated March 19, 2012 for the May 4, 2012 Annual Meeting of Shareholders. Additional financial information is also provided in the 2011 Audited Consolidated Financial Statements and the MD&A.

Requests for additional copies of the above-mentioned documents, as well as the 2011 Annual Information Form, should be directed to the Corporate Secretary, Fortis, P.O. Box 8837, St. John's, NL, A1B 3T2 (telephone: 709.737.2800). In addition, such documentation and additional information relating to the Corporation is contained on the Corporation's website at www.fortisinc.com.

FORTIS INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2012

March 22, 2013

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2012

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DEFINITIONS OF CERTAIN TERMS

Certain terms used in this Annual Information Form are defined below:

"2012 Annual Information Form" means this Fortis Inc. Annual Information Form in respect of the year ended December 31, 2012;

"2012 Audited Consolidated Financial Statements" means the audited comparative consolidated financial statements of Fortis Inc. as at and for the year ended December 31, 2012 and related notes thereto;

"Abitibi" means AbitibiBowater Inc.;

"Accord Continuation Act" means the *Electric Power (Energy Accord Continuation) Amendment Act* (Prince Edward Island);

"Algoma Power" means Algoma Power Inc.;

"AUC" means Alberta Utilities Commission;

"BC Hydro" means BC Hydro and Power Authority;

"BCUC" means British Columbia Utilities Commission;

"BECOL" means Belize Electric Company Limited;

"Belize Electricity" means Belize Electricity Limited;

"BEPC" means Brilliant Expansion Power Corporation;

"Board" means Board of Directors of Fortis Inc.;

"BPC" means Brilliant Power Corporation;

"Brilliant Corporation" means Brilliant Expansion Power Corporation;

"Canadian GAAP" means Canadian generally accepted accounting principles;

"Canadian Niagara Power" means Canadian Niagara Power Inc.;

"Caribbean Utilities" means Caribbean Utilities Company, Ltd.;

"CAW" means Canadian Auto Workers-Retail/Wholesale;

"CEA" means Canadian Electricity Association;

"Central Hudson" means Central Hudson Gas & Electric Corporation;

"CEP" means Communications, Energy and Paperworkers Union;

"CH Energy Group" means CH Energy Group, Inc.;

"COPE" means Canadian Office and Professional Employees Union;

"Cornwall Electric" means Cornwall Street Railway, Light and Power Company, Limited;

"Corporation" means Fortis Inc.;

"CPA" means Canal Plant Agreement;

"CPC/CBT" means Columbia Power Corporation and Columbia Basin Trust;

"CUPE" means Canadian Union of Public Employees;

“DBRS” means DBRS Limited;

“EMS” means environmental management system;

“Exploits Partnership” means Exploits River Hydro Partnership between Abitibi and Fortis Properties Corporation;

“External Auditor” means the firm of chartered accountants registered with the Canadian Public Accountability Board or its successor and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

“FAES” means FortisBC Alternative Energy Services Inc.;

“FEI” means FortisBC Energy Inc.;

“FERC” means United States Federal Energy Regulatory Commission;

“FEVI” means FortisBC Energy (Vancouver Island) Inc.;

“FEWI” means FortisBC Energy (Whistler) Inc.;

“FHI” means FortisBC Holdings Inc., the parent company of FEI, FEVI and FEWI;

“Fortis” means Fortis Inc.;

“FortisAlberta” means FortisAlberta Inc.;

“FortisAlberta Holdings” means FortisAlberta Holdings Inc.;

“FortisBC Electric” means, collectively, the operations of FortisBC Inc. and its parent company, FortisBC Pacific Holdings Inc., but excluding its wholly owned partnership, Walden Power Partnership;

“FortisBC Energy companies” means, collectively, the operations of FEI, FEVI and FEWI;

“FortisBC Pacific Holdings” means FortisBC Pacific Holdings Inc.;

“FortisOntario” means, collectively, the operations of Canadian Niagara Power, Cornwall Electric and Algoma Power;

“Fortis Generation East Partnership” means Fortis Generation East LLP;

“Fortis Properties” means Fortis Properties Corporation;

“FortisTCI” means FortisTCI Limited;

“Fortis Turks and Caicos” means, collectively, FortisTCI, Atlantic Equipment & Power (Turks and Caicos) Ltd. and Turks and Caicos Utilities Limited;

“FortisUS Energy” means FortisUS Energy Corporation;

“FortisWest” means FortisWest Inc.;

“GHG” means greenhouse gas;

“GOB” means Government of Belize;

“GSMIP” means Gas Supply Mitigation Incentive Plan;

“GWh” means gigawatt hour(s);

“Hilton Suites Hotel” means Hilton Suites Winnipeg Airport hotel;

“Hydro One” means Hydro One Networks Inc.;

"IBEW" means International Brotherhood of Electrical Workers;

"IESO" means Independent Electricity System Operator of Ontario;

"IFRS" means International Financial Reporting Standards;

"ISO" means International Organization for Standardization;

"LNG" means liquefied natural gas;

"Management" means, collectively, senior officers of the Corporation;

"Maritime Electric" means Maritime Electric Company, Limited;

"MD&A" means the Corporation's Management Discussion and Analysis, located on pages 7 through 81 of the Corporation's 2012 Annual Report to Shareholders, prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations,* in respect of the Corporation's annual consolidated financial statements for the year ended December 31, 2012;

"Moody's" means Moody's Investors Service;

"MW" means megawatt(s);

"MWh" means megawatt hours;

"NB Power" means New Brunswick Power Corporation;

"NEB" means National Energy Board;

"Newfoundland Hydro" means Newfoundland and Labrador Hydro Corporation;

"Newfoundland Power" means Newfoundland Power Inc.;

"NYSPSC" means New York State Public Service Commission;

"OEB" means Ontario Energy Board;

"Other Canadian Electric Utilities" means, collectively, the operations of FortisOntario and Maritime Electric;

"PCB" means polychlorinated biphenyl;

"PBR" means performance-based rate-setting;

"PEI" means Prince Edward Island;

"PEI Energy Accord" means Prince Edward Island Energy Accord;

"PEI Energy Commission" means Prince Edward Island Energy Commission;

"PJ" means petajoule(s);

"Point Lepreau" means NB Power Point Lepreau Nuclear Generating Station;

"PPA" means power purchase agreement;

"PRMP" means Price Risk Management Plan;

"PUB" means Newfoundland and Labrador Board of Commissioners of Public Utilities;

"ROE" means rate of return on common shareholders' equity;

"S&P" means Standard & Poor's;

"SEDAR" means the System for Electronic Document Analysis and Retrieval;

"Spectra Energy" means Westcoast Energy Inc. doing business as Spectra Energy Transmission;

"StationPark Hotel" means StationPark All Suite Hotel;

"T&D" means transmission and distribution;

"TCU" means Turks and Caicos Utilities Limited;

"Teck Metals" means Teck Metals Ltd.;

"TJ" means terajoule(s);

"TransCanada" means TransCanada Pipelines Limited;

"TSA" means Transportation Service Agreement;

"TSX" means Toronto Stock Exchange;

"UFCW" means United Food and Commercial Workers;

"US GAAP" means accounting principles generally accepted in the United States;

"USW" means United Steel Workers;

"Walden" means Walden Power Partnership;

"Waneta Expansion" means the 335-MW hydroelectric generating facility being constructed adjacent to the existing Waneta Plant on the Pend d'Oreille River in British Columbia;

"Waneta Partnership" means the Waneta Expansion Limited Partnership between CPC/CBT and Fortis;

"WECA" means the Waneta Expansion Capacity Agreement; and

"Whistler" means the Resort Municipality of Whistler.

1.0 CORPORATE STRUCTURE

The 2012 Annual Information Form has been prepared in accordance with National Instrument 52-102 - *Continuous Disclosure Obligations*. Financial information has been prepared in accordance with US GAAP and is presented in Canadian dollars unless otherwise specified. Financial information prior to 2010 has been prepared in accordance with Canadian GAAP.

Except as otherwise stated, the information in the 2012 Annual Information Form is given as of December 31, 2012.

Fortis includes forward-looking information in the 2012 Annual Information Form within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. 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 management. The forward-looking information in the 2012 Annual Information Form, including the 2012 MD&A incorporated herein by reference, includes, but is not limited to, statements regarding: the principal business of Fortis remaining the ownership and operation of regulated electric and gas utilities; the Corporation's primary focus on the United States in the acquisition of regulated utilities; the pursuit of growth in the Corporation's non-regulated businesses in support of its regulated utility growth strategy; the expected capital investment in Canada's electricity sector over the 20-year period from 2010 through 2030 to maintain system reliability; the expected timing of the closing of the acquisition of CH Energy Group by Fortis and the expectation that the acquisition will be accretive to earnings per common share of Fortis within the first full year of ownership, excluding acquisition-related expenses; the Corporation's expected regulated midyear rate base in 2013 upon closing of the CH Energy Group acquisition; forecasted 2013 midyear rate base for the Corporation's four large regulated utilities and Central Hudson; the Corporation's consolidated forecasted gross capital expenditures for 2013 and in total over the five years 2013 through 2017 and average annual capital expenditures at Central Hudson over the same time period; the expected combined compound annual growth rate of utility rate base and hydroelectric generation investment over the next five years; the expectation that FortisAlberta's load and rate base will be positively impacted as a result of continuing economic growth in Alberta; various natural gas and electricity transmission investment opportunities that may be available to the Corporation; an expected favourable impact on the Corporation's earnings in future periods upon final enactment of legislative changes to Part VI.1 taxes; the nature, timing and amount of certain capital projects and their expected costs and time to complete; the expectation that the Corporation's significant capital expenditure program will support continuing growth in earnings and dividends; there is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed; the expectation that the Corporation's regulated utilities could experience disruptions and increased costs if they are unable to maintain their asset base; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long-term debt offerings; the expectation that the Corporation's subsidiaries will be able to source the cash required to fund their 2013 capital expenditure programs; the expected consolidated long-term debt maturities and repayments in 2013 and on average annually over the next five years; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to capital in the near to medium terms; the expectation that the combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets; except for debt at the Exploits Partnership, the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2013; the expectation that any increase in interest expense and/or fees associated with renewed and extended credit facilities will not materially impact the Corporation's consolidated financial results for 2013; the expected impact on 2013 earnings for each of the FortisBC Energy companies, FortisAlberta, FortisBC Electric and Newfoundland Power of changes in the allowed ROE and common equity component of total capital structure; the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the estimated impact a decrease in revenue at Fortis Properties' Hospitality Division would have on annual basic earnings per common share; no expected material adverse credit rating actions in the near term; the expected impact of a change in the US dollar-to-Canadian dollar foreign exchange rate on basic earnings per common share in 2013; the expectation that counterparties to the FortisBC Energy companies' gas derivative contracts will continue to meet their obligations; and the expectation that consolidated defined benefit net pension cost for 2013 will be comparable to that in 2012 and that there is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future.

The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received and the expectation of regulatory stability; FortisAlberta continues to recover its cost of service and earn its allowed ROE under PBR, which commenced for a five-year term effective January 1, 2013; the receipt of regulatory approval from the NYSPSC of a settlement agreement, as filed, pertaining to the acquisition of CH Energy Group; the closing of the acquisition of CH Energy Group before the expiry of the Subscription Receipts on June 30, 2013; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; no material capital project and financing cost overrun related to the construction of the Waneta Expansion; sufficient liquidity and capital resources; the expectation that the Corporation will receive appropriate compensation from the GOB for fair value of the Corporation's investment in Belize Electricity that was expropriated by the GOB; the expectation that BECOL will not be expropriated by the GOB; the expectation that the Corporation will receive fair compensation from the Government of Newfoundland and Labrador related to the expropriation of the Exploits Partnership's hydroelectric assets and water rights; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in interest rates, foreign exchange rates, natural gas commodity prices and fuel prices; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans and environmental laws that may materially negatively affect the operations and *cash flows of the Corporation and its subsidiaries; no material change in public policies and directions by governments that could materially negatively affect the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under US GAAP beyond 2014 or the adoption of IFRS after 2014 that allows for the recognition of regulatory assets and liabilities; the continued tax-deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology infrastructure; continued favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program.*

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. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risk Management" in the MD&A for the year ended December 31, 2012 and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. Key risk factors for 2013 include, but are not limited to: uncertainty of the impact a continuation of a low interest rate environment may have on the allowed ROE at each of the Corporation's four large Canadian regulated utilities; uncertainty regarding the treatment of certain capital expenditures at FortisAlberta under the newly implemented PBR mechanism; risks relating to the ability to close the acquisition of CH Energy Group, the timing of such closing and the realization of the anticipated benefits of the acquisition; risk associated with the amount of compensation to be paid to Fortis for its investment in Belize Electricity that was expropriated by the GOB; and the timeliness of the receipt of the compensation and the ability of the GOB to pay the compensation owing to Fortis.

All forward-looking information in the 2012 Annual Information Form is qualified in its entirety by the above cautionary statements 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.

1.1 Name and Incorporation

Fortis is a holding company that was incorporated as 81800 Canada Ltd. under the *Canada Business Corporations Act* on June 28, 1977 and continued under the *Corporations Act* (Newfoundland and Labrador) on August 28, 1987.

The articles of incorporation of the Corporation were amended to: (i) change its name to Fortis on October 13, 1987; (ii) set out the rights, privileges, restrictions and conditions attached to the Common Shares on October 15, 1987; (iii) designate 2,000,000 First Preference Shares, Series A on September 11, 1990; (iv) replace the class rights, privileges, restrictions and conditions attaching to the First Preference Shares and the Second Preference Shares on July 22, 1991; (v) designate 2,000,000 First Preference Shares, Series B on December 13, 1995; (vi) designate 5,000,000 First Preference Shares, Series C on May 27, 2003; (vii) designate 8,000,000 First Preference Shares, Series D and First Preference Shares, Series E on January 23, 2004; (viii) amend the redemption provisions attaching to the First Preference Shares, Series D on July 15, 2005; (ix) designate 5,000,000 First Preference Shares, Series F on September 22, 2006; (x) designate 9,200,000 First Preference Shares, Series G on May 20, 2008; (xi) designate 10,000,000 First Preference Shares, Series H and 10,000,000 First Preference Shares, Series I on January 20, 2010; and (xii) designate 8,000,000 First Preference Shares, Series J on November 8, 2012.

Fortis redeemed all of its outstanding First Preference Shares, Series A and First Preference Shares, Series B on September 30, 1997 and December 2, 2002, respectively. On June 3, 2003, Fortis issued 5,000,000 First Preference Shares, Series C. On January 29, 2004, Fortis issued 8,000,000 First Preference Units, each unit consisting of one First Preference Share, Series D and one Warrant. During 2004 7,993,500 First Preference Units were converted into 7,993,500 First Preference Shares, Series E and 6,500 First Preference Shares, Series D remained outstanding. On September 20, 2005, the 6,500 First Preference Shares, Series D were redeemed by the Corporation. On September 28, 2006, Fortis issued 5,000,000 First Preference Shares, Series F. On May 23, 2008, Fortis issued 8,000,000 First Preference Shares, Series G and on June 4, 2008 issued an additional 1,200,000 First Preference Shares, Series G, following the exercise of an over-allotment option in connection with the offering of the 8,000,000 First Preference Shares, Series G. On January 26, 2010, Fortis issued 10,000,000 First Preference Shares, Series H. On November 13, 2012, Fortis issued 8,000,000 First Preference Shares, Series J.

The corporate head and registered office of Fortis is located at the Fortis Building, Suite 1201, 139 Water Street, P.O. Box 8837, St. John's, NL, Canada, A1B 3T2.

1.2 Inter-Corporate Relationships

Fortis is the largest investor-owned distribution utility in Canada. Its regulated holdings include electric utilities in five Canadian provinces and two Caribbean countries and a natural gas utility in British Columbia, Canada. As at December 31, 2012, regulated utility assets comprised approximately 90% of the Corporation's total assets, with the balance mainly comprised of non-regulated generation assets, primarily hydroelectric, across Canada and in Belize and Upstate New York, and hotels and commercial office and retail space in Canada.

The following table lists the principal subsidiaries of the Corporation, their jurisdictions of incorporation and the percentage of votes attaching to voting securities held directly or indirectly by the Corporation as at March 22, 2013. This table excludes certain subsidiaries, the total assets of which individually constituted less than 10% of the Corporation's consolidated assets as at December 31, 2012, or the total revenue of which individually constituted less than 10% of the Corporation's 2012 consolidated revenue. Additionally, the principal subsidiaries together comprise approximately 79% of the Corporation's consolidated assets as at December 31, 2012 and approximately 76% of the Corporation's 2012 consolidated revenue.

Principal Subsidiaries		
Subsidiary	**Jurisdiction of Incorporation**	**Percentage of votes attaching to voting securities beneficially owned, controlled or directed by the Corporation**
FHI	British Columbia	100
FortisAlberta *(1)*	Alberta	100
FortisBC Inc. *(2)*	British Columbia	100
Newfoundland Power	Newfoundland and Labrador	94 *(3)*

(1) *FortisAlberta Holdings, an Alberta corporation, owns all of the shares of FortisAlberta. FortisWest, a Canadian corporation, owns all of the shares of FortisAlberta Holdings. Fortis owns all of the shares of FortisWest.*

(2) *FortisBC Pacific Holdings, a British Columbia corporation, owns all of the shares of FortisBC Inc. FortisWest, a Canadian corporation, owns all of the shares of FortisBC Pacific Holdings. Fortis owns all of the shares of FortisWest.*

(3) *Fortis owns all of the common shares; 1,713 First Preference Shares, Series A; 36,031 First Preference Shares, Series B; 13,700 First Preference Shares, Series D and 182,300 First Preference Shares, Series G of Newfoundland Power which, as at March 22, 2013, represented 94% of its voting securities. The remaining 6% of Newfoundland Power's voting securities consist of First Preference Shares, Series A, B, D and G, which are primarily held by the public.*

2.0 GENERAL DEVELOPMENT OF THE BUSINESS

2.1 Three-Year History

Over the past three years, Fortis has experienced growth in its business operations. Total assets have grown 24% from approximately $12.1 billion as at December 31, 2009 to approximately $15.0 billion as at December 31, 2012. The Corporation's shareholders' equity has also grown 46% from approximately $3.7 billion as at December 31, 2009 to approximately $5.4 billion as at December 31, 2012. Net earnings attributable to common equity shareholders have increased from $262 million in 2009 to $315 million in 2012.

The growth in business operations reflects the Corporation's profitable growth strategy for its principal businesses of regulated gas and electricity distribution. This strategy includes a combination of organic growth through the Corporation's consolidated capital expenditure program and growth through acquisitions.

The Corporation's consolidated capital expenditure program surpassed $1 billion in 2012 for the fourth consecutive year. Organic asset growth at the regulated utilities has been driven by the capital expenditure programs at FortisAlberta, FortisBC Electric and the FortisBC Energy companies. Total assets at FortisAlberta, FortisBC Electric and the FortisBC Energy companies have grown by approximately 42%, 41% and 10%, respectively, over the past three years. At FortisBC Electric, a portion of the growth in its total assets related to the recognition of certain capital leases upon the transition to US GAAP. Organic growth at non-regulated operations has been driven by approximately $436 million in total that has been spent on the Waneta Expansion since construction began in late 2010.

Over the past three years, Fortis increased its regulated utility investments in Canada and the Caribbean through the purchase of the electricity distribution assets in Port Colborne in April 2012 for $7 million and through the acquisition of TCU in August 2012 for $8 million, net of debt assumed. FortisOntario exercised its option to purchase all of the assets previously leased by the Company under an operating lease agreement with the City of Port Colborne, which provides ownership and legal title to all of the assets that constitute the electricity distribution system in Port Colborne. TCU is a regulated electric utility serving more than 2,000 residential and commercial customers on Grand Turk and Salt Cay. The Corporation also increased its non-regulated investments, over the last three years, through the acquisition of two hotels in Canada.

The GOB expropriated the Corporation's investment in Belize Electricity in June 2011. As a result of no longer controlling the operations of the utility, the Corporation discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011. For further information refer to the "Expropriated Assets" heading in Section 3.3 of this 2012 Annual Information Form.

2.2 Pending Acquisition

In February 2012 Fortis announced that it had entered into an agreement to acquire CH Energy Group for US$65.00 per common share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of approximately US$500 million of debt on closing. CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson, is a regulated T&D utility serving approximately 300,000 electric and 75,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. The transaction received CH Energy Group shareholder approval in June 2012 and regulatory approval from FERC and the Committee on Foreign Investment in the United States in July 2012. In addition, the waiting period under the *Hart-Scott-Rodino Antitrust Improvements Act of 1976* expired in October 2012, satisfying another condition necessary for consummation of the transaction.

Approval by the NYSPSC of the Corporation's acquisition of CH Energy Group is the last significant regulatory matter required to close the transaction. Closing of the transaction is now anticipated during the second quarter of 2013. The transaction is expected to be accretive to the Corporation's earnings per common share within the first full year of ownership of CH Energy Group, excluding acquisition-related expenses. A Settlement Agreement among Fortis, CH Energy Group, NYSPSC staff, registered interveners and other parties was filed with the NYSPSC in January 2013. The Settlement Agreement provides almost $50 million to fund customer and community benefits, including: (i) $35 million to cover expenses that normally would be recovered in customer rates, for example, storm-restoration expenses; (ii) guaranteed savings to customers of more than $9 million over five years resulting from the elimination of costs Central Hudson now incurs as a public company; and (iii) the establishment of a $5 million Customer Benefit Fund for economic development and low-income assistance programs for communities and residents of the Mid-Hudson River Valley. Another benefit provided under the Settlement Agreement is an electric and natural gas customer delivery rate freeze until July 1, 2014. The Settlement Agreement also contains customer protections, including the continuation of Central Hudson as a stand-alone utility. The parties to the Settlement Agreement have concluded that, based on the terms of the Settlement Agreement, the acquisition is in the public interest and have recommended approval by the NYSPSC.

2.3 Outlook

Over the five-year period 2013 through 2017, gross consolidated capital expenditures, including expenditures at Central Hudson, are expected to be approximately $6 billion. Central Hudson's capital program over the next five years is expected to average more than $125 million annually. The approximate breakdown of the capital spending expected to be incurred is as follows: 55% at Canadian Regulated Electric Utilities, driven by FortisAlberta; 19% at Canadian Regulated Gas Utilities; 11% at Central Hudson; 4% at Caribbean Regulated Electric Utilities; and the remaining 11% at non-regulated operations. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, the approximate breakdown of the total capital spending to be incurred is as follows: 36% to meet customer growth; 41% for sustaining capital expenditures; and 23% for facilities, equipment, vehicles, information technology and other assets.

The Corporation's capital program will support continuing growth in earnings and dividends. Capital investment should allow the Corporation's consolidated regulated midyear rate base, including incremental investment in rate base by Central Hudson, and investment in the non-regulated Waneta Expansion to increase at a combined compound annual growth rate of approximately 6% through 2017.

Gross consolidated capital expenditures for 2013 are expected to be approximately $1.3 billion, as summarized in the following table. Planned capital expenditures are based on detailed forecasts of energy demand, weather, cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from forecasts.

Forecast Gross Consolidated Capital Expenditures *(1)* **Year Ending December 31, 2013**	
	($ millions)
FortisBC Energy Companies	229
FortisAlberta	437
FortisBC Electric	133
Newfoundland Power	86
Other Canadian Electric Utilities	54
Regulated Electric Utilities - Caribbean	49
Non-Regulated - Fortis Generation	229
Fortis Properties and Other *(2)*	113
Total	**1,330**

(1) *Relates to forecasted cash payments to acquire or construct utility capital assets, income producing properties and intangible assets, as would be reflected on the consolidated statement of cash flows. Excludes forecasted capitalized depreciation and amortization and non-cash equity component of allowance for funds used during construction.*

(2) *Includes forecasted capital expenditures of approximately $70 million at Fortis Properties, and approximately $43 million at FAES, which is included in the Corporate and Other segment.*

The Corporation's subsidiaries expect to have reasonable access to long-term capital in 2013 to fund their capital expenditure programs.

Forecasted 2013 midyear rate base for the Corporation's four large Canadian regulated utilities is provided in the following table.

Forecast Midyear Rate Base *($ billions)*	**2013**
FortisBC Energy Companies	3.7
FortisAlberta	2.3
FortisBC Electric	1.2
Newfoundland Power	0.9

Central Hudson's midyear rate base for 2013 is expected to be almost $1 billion.

Approval by the NYSPSC of the Corporation's acquisition of CH Energy Group is the last significant regulatory matter required to close the transaction. The transaction is anticipated to close during the second quarter of 2013. With the acquisition of CH Energy Group, the Corporation's regulated midyear rate base will increase to approximately $10 billion.

Fortis is focused on closing the CH Energy Group acquisition. Fortis also remains disciplined and patient in its pursuit of additional electric and gas utility acquisitions in the United States and Canada that will add value for Fortis shareholders. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

3.0 DESCRIPTION OF THE BUSINESS

Fortis is principally an international distribution utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets, and commercial office and retail space and hotels, which are treated as two separate segments. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates autonomously, assumes profit and loss responsibility and is accountable for its own resource allocation.

The business segments of the Corporation are: (i) Regulated Gas Utilities - Canadian; (ii) Regulated Electric Utilities - Canadian; (iii) Regulated Electric Utilities - Caribbean; (iv) Non-Regulated - Fortis Generation; (v) Non-Regulated - Fortis Properties; and (vi) Corporate and Other.

The following sections describe the operations included in each of the Corporation's reportable segments.

3.1 Regulated Gas Utilities - Canadian

3.1.1 *FortisBC Energy Companies*

The Regulated Gas Utilities - Canadian segment comprises the natural gas T&D business of the FortisBC Energy companies, which includes FEI, FEVI and FEWI.

FEI is the largest distributor of natural gas in British Columbia, serving approximately 841,000 customers in more than 100 communities. Major areas served by FEI are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of British Columbia.

FEVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island, and serves more than 101,000 customers on Vancouver Island and along the Sunshine Coast of British Columbia.

FEWI owns and operates the natural gas distribution system in Whistler, British Columbia, which provides service to approximately 3,000 customers.

In addition to providing T&D services to customers, the FortisBC Energy companies also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

The FortisBC Energy companies own and operate approximately 47,000 kilometres of natural gas pipelines and met a peak day demand of 1,336 TJ in 2012.

Market and Sales

Annual customer natural gas volumes at the FortisBC Energy companies decreased to 199 PJ in 2012 from 203 PJ in 2011. Revenue decreased to approximately $1,426 million in 2012 from $1,566 million in 2011. The decrease in revenue was primarily due to lower commodity cost of natural gas charged to customers.

The following table compares the composition of 2012 and 2011 revenue and natural gas volumes of the FortisBC Energy companies by customer class.

FortisBC Energy Companies Revenue and Gas Volumes by Customer Class				
	Revenue (%)		**PJ Volumes (%)**	
	2012	2011	**2012**	2011
Residential	**55.7**	56.7	**36.7**	38.9
Commercial	**27.3**	28.9	**23.6**	24.1
Industrial	**6.7**	6.0	**3.0**	3.0
	89.7	91.6	**63.3**	66.0
Transportation	**6.0**	4.8	**36.2**	33.5
Other (1)	**4.3**	3.6	**0.5**	0.5
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes amounts under fixed-revenue contracts and revenue from sources other than from the sale of natural gas*

Transportation Service Agreements

In 2007 the BCUC approved a long-term TSA and related agreements between FEVI and BC Hydro under which FEVI provides firm and interruptible transportation service to serve the Island Cogeneration Project at Elk Falls on Vancouver Island. The initial term of the TSA is from January 1, 2008 through April 12, 2022. Tolls for firm and interruptible service are determined by the BCUC from time to time. The initial contract demand was 45 TJ per day, which BC Hydro can change to a minimum of 40 TJ per day or a maximum of 50 TJ per day by giving 12 months' notice. Effective November 1, 2012, BC Hydro decreased their contracted demand from 45 TJ to 40 TJ per day.

Under the terms of the TSA, BC Hydro may elect to terminate the TSA on or after November 1, 2015 upon giving two years' notice. In addition, BC Hydro may reduce the contract demand or terminate the TSA if FEVI gives notice of its intention to construct expansion facilities that would impact transportation tolls payable by BC Hydro. If BC Hydro elects to terminate, it may by the terms of the TSA be required to make a termination payment to FEVI that would, in essence, compensate FEVI for incremental revenue requirements relating to expansion facilities constructed by FEVI after January 1, 2008, but prior to BC Hydro's notice of termination.

Gas Purchase Agreements

In order to ensure supply of adequate resources to provide reliable natural gas deliveries to its customers, the FortisBC Energy companies purchase supplies from a select list of producers, aggregators and marketers, while adhering to standards of counterparty creditworthiness and contract execution and/or management policies. FEI contracts for approximately 114 PJ of baseload and seasonal supply to meet the requirements of both FEI and FEWI, of which 102 PJ is sourced in north eastern British Columbia and transported to FEI's system on Spectra Energy's westcoast pipeline system, and 12 PJ is comprised of Alberta-sourced supply, transported into British Columbia via TransCanada's Alberta and British Columbia systems and then through FEI's Southern Crossing pipeline. FEVI contracts for about 11 PJ of annual supply comprised of baseload and seasonal contracts, primarily sourced in British Columbia.

Through the operation of regulatory deferrals, any difference between forecasted cost of natural gas purchases, as reflected in residential and commercial customer rates, and the actual cost of natural gas purchases is recovered from, or refunded to, customers in future rates. The majority of supply contracts in the current portfolio are seasonal for either the summer period (April to October) or winter period (November to March) with a few contracts one year or longer in length.

Core market customers rely upon the FortisBC Energy companies to procure and deliver gas supply on their behalf, while transportation-only industrial customers are responsible for procuring and delivering their own gas supply directly to the FortisBC Energy companies' system, which is then delivered to their operating premises by the FortisBC Energy companies. FEI and FEVI contract for capacity on third-party pipelines, such as those owned by Spectra Energy and TransCanada, which are regulated by the NEB, for transportation of gas supply from various market hubs and locations to FEI's system, which is then transported to the FEVI and FEWI systems. The FortisBC Energy companies pay both fixed and variable charges for the use of capacity on these pipelines, which are recovered through rates paid by core market customers. The FortisBC Energy companies contract for firm capacity in order to ensure they are able to meet their obligations to supply customers within their broad operating region under all reasonable demand scenarios.

Gas Storage and Peak-Shaving Arrangements

The FortisBC Energy companies incorporate peak shaving and gas storage facilities into their portfolio to:

(i) supplement contracted baseload and seasonal gas supply in the winter months while injecting excess baseload supply to refill storage in the summer months;
(ii) eliminate the risk of supply shortages during cooler weather and peak throughput day;
(iii) effectively manage the cost of gas during winter months; and
(iv) balance daily supply and demand on the distribution system, mainly over the course of the winter months.

FEI holds approximately 31.4 PJ of total storage capacity, consisting of on-system peak-shaving LNG facilities owned by FEI and FEVI and off-system capacity contracted with third parties. The FEVI-owned Mount Hayes LNG storage facility provides FEI with an additional 1.4 PJ of storage capacity and 0.14 PJ per day of deliverability for storage withdrawals. The Tilbury LNG storage facility provides FEI with 0.61 PJ of total storage capacity and 0.16 PJ per day of deliverability for storage withdrawals. FEI also contracts for storage capacity from external parties at various locations throughout British Columbia, Alberta and the Pacific Northwest region of the United States. These storage facilities and supply from peak-shaving contracts can deliver a maximum daily rate of 0.7 PJ on a combined basis during the coldest months of December through February. The resources held by FEI are also used to serve FEWI.

FEVI holds a total of 3 PJ of storage capacity, including off-system capacity contracted with third parties and on-system capacity provided by the Mount Hayes LNG storage facility. The Mount Hayes LNG storage facility provides FEVI with both peaking gas supply and system capacity during extreme cold events and emergencies.

Off-System Sales

FEI engages in off-system sales activities which allow for the recovery of, or mitigation of, costs on any unutilized supply and/or pipeline capacity that is available once customers' daily load requirements are met. Under the GSMIP revenue-sharing model, which is approved by the BCUC, FEI can earn an incentive payment for its mitigation activities based on the total savings generated for customers. Historically, FEI has earned approximately $1 million annually through the GSMIP while the remaining savings are credited back to customers through reduced rates. In the gas contract year ended October 31, 2012, total net revenue was approximately $28 million as a result of FEI's mitigation activities, on which FEI earned an incentive payment of approximately $1 million. The remaining savings will be returned to customers through rates.

The current GSMIP program, which was approved by the BCUC following a review of the program in 2011, defines the revenue sharing between customers and the shareholder and is effective for the two-year period from November 1, 2011 to October 31, 2013.

Price Risk Management Plan

In the past FEI and FEVI have engaged in hedging activities to minimize the exposure to fluctuations in the market price of natural gas through the use of derivative instruments, pursuant to a BCUC-approved PRMP. The primary objectives of the hedging strategy incorporated in the PRMP were to reduce price volatility and ensure, to the extent possible, that natural gas commodity costs remain competitive against electricity rates. In July 2010 the BCUC ordered a review of FEI's PRMP hedging strategy in the context of the *Clean Energy Act* (British Columbia) and expectation of increased domestic natural gas supply. In July 2011 following an extensive review process, the BCUC determined that the hedging strategy was no longer in the best interests of customers and directed FEI to suspend the majority of its gas commodity hedging activities. FEI was further directed to manage hedges already in place through to expiry.

Following the BCUC’s decision to suspend FEI’s hedging activities, FEVI subsequently withdrew its request to implement a hedging strategy. The existing hedging contracts will continue in effect through to their maturity and the FortisBC Energy companies’ ability to fully recover the commodity cost of gas in customer rates remains unchanged. FEI currently has hedges in place through to the end of March 2014 from previously approved PRMPs. Similarly, FEVI has hedges in place through to October 2014.

Unbundling

The FEI Customer Choice Program allows eligible FEI commercial and residential customers to choose to buy their natural gas commodity supply from FEI or directly from third-party marketers. FEI continues to provide delivery of the natural gas to all its customers.

The Customer Choice Program has been in place since November 2004 for commercial customers and November 2007 for residential customers. As of December 31, 2012, of the approximately 76,000 eligible commercial customers, approximately 9,900 are currently participating in the program by purchasing their commodity supply from alternate providers. Approximately 760,000 residential customers are eligible of which 55,000 customers were participating in the program as at December 31, 2012.

Legal Proceedings

During 2007 and 2008, a non-regulated subsidiary of FHI received Notices of Assessment from Canada Revenue Agency for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the Corporation’s 2012 Audited Consolidated Financial Statements. FHI is appealing the assessments.

In 2009 FHI was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to the rupture in July 2007 of an oil pipeline owned and operated by Kinder Morgan, Inc. FHI filed a statement of defence. During the second quarter of 2010, FHI was added as a third party in all of the related actions. FHI was advised that all matters have now been settled and the action has been dismissed by consent.

Human Resources

As at December 31, 2012, the FortisBC Energy companies employed 1,681 full-time equivalent employees. Approximately 72% of the employees are represented by IBEW, Local 213, and COPE, Local 378, under collective agreements.

IBEW, Local 213, represents employees in specified occupations in the areas of T&D. A new IBEW collective agreement came into effect in mid-2012 and expires on March 31, 2015.

There are two collective agreements between the FortisBC Energy companies and COPE. The first collective agreement representing employees in specified occupations in the areas of administration and operations support expires on March 31, 2015. The second COPE collective agreement representing customer service employees expires on March 31, 2014.

3.2 Regulated Electric Utilities - Canadian

3.2.1 *FortisAlberta*

FortisAlberta is a regulated electric distribution utility in the province of Alberta. Its business is the ownership and operation of regulated electricity distribution facilities that distribute electricity, generated by other market participants, from high-voltage transmission substations to end-use customers. FortisAlberta is not involved in the generation, transmission or direct sale of electricity. FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, totalling approximately 116,000 kilometres of distribution lines. Many of the Company's customers are located in rural and suburban areas around and between the cities of Edmonton and Calgary. FortisAlberta's distribution network serves approximately 508,000 customers, comprising residential, commercial, farm, oil and gas and industrial consumers of electricity, and met a peak demand of 2,652 MW in 2012.

Market and Sales

FortisAlberta's annual energy deliveries increased to 16,799 GWh in 2012 from 16,367 GWh in 2011. Revenue was $448 million in 2012 compared to $408 million in 2011.

As a significant portion of FortisAlberta's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

The following table compares the composition of FortisAlberta's 2012 and 2011 revenue and energy deliveries by customer class.

FortisAlberta
Revenue and Energy Deliveries by Customer Class

	Revenue (%)		**GWh Deliveries (1) (%)**	
	2012	2011	**2012**	2011
Residential	**30.5**	31.2	**16.7**	17.0
Large commercial, industrial and oil field	**20.9**	20.9	**61.9**	61.0
Farms	**12.5**	13.1	**7.5**	7.9
Small commercial	**11.0**	11.2	**7.8**	7.9
Small oil field	**8.8**	9.0	**5.7**	5.8
Other (2)	**16.3**	14.6	**0.4**	0.4
Total	**100.0**	100.0	**100.0**	100.0

(1) *GWh percentages presented exclude FortisAlberta's GWh deliveries to "transmission-connected" customers. These deliveries were 7,195 GWh in 2012 and 7,100 GWh in 2011 and consisted primarily of energy deliveries to large-scale industrial customers directly connected to the transmission grid.*

(2) *Includes revenue from sources other than the delivery of energy, including that related to street-lighting services, rate riders, deferrals and adjustments*

Franchise Agreements

FortisAlberta serves customers residing within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta located within their municipal boundaries. Upon the termination, or in the absence of a franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta) with the price to be as agreed by the Company and the municipality, failing which it is to be determined by the AUC. Additionally, under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric distribution system expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides that the AUC may determine that the municipality should pay compensation to the Company for any facilities transferred on the basis of replacement cost less depreciation. Given the historical population and economic growth of Alberta and its municipalities, FortisAlberta is affected by transactions of this type from time to time.

FortisAlberta holds franchise agreements with 141 municipalities within its service area. In the fourth quarter of 2012, FortisAlberta received approval of a new franchise agreement template from the AUC. The new template was filed with the AUC following negotiations with the Alberta Urban Municipalities Association and consultation with municipalities. The new franchise agreement template includes a 10-year term with an option that will permit the agreement to automatically renew for a further five years. In 2013 FortisAlberta will begin moving all 141 municipalities to the new agreement.

Human Resources

As at December 31, 2012, FortisAlberta had 1,107 full-time equivalent employees. Approximately 75% of the employees of the Company are members of a labour association represented by United Utility Workers' Association, Local 200, under a three-year collective agreement that expires on December 31, 2013.

3.2.2 *FortisBC Electric*

FortisBC Electric includes FortisBC Inc., 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. FortisBC Inc. serves a diverse mix of approximately 163,000 customers, of whom approximately 113,900 are served directly by the Company's assets in communities that include Kelowna, Oliver, Osoyoos, Trail, Castlegar, Creston and Rossland, while the remainder are served through the wholesale supply of power to municipal distributors. In 2012 FortisBC Inc. met a peak demand of 737 MW. Residential customers represent the largest customer class of the Company. FortisBC Electric's T&D assets include approximately 7,000 kilometres of T&D lines and 65 substations.

FortisBC Electric also includes operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals and BC Hydro, the 149-MW Brilliant hydroelectric plant and 120-MW Brilliant hydroelectric expansion plant, both owned by CPC/CBT, the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT, and the distribution system owned by the City of Kelowna.

Market and Sales

FortisBC Electric has a diverse customer base composed primarily of residential, commercial, industrial and municipal wholesale, and other industrial customers. Annual electricity sales were 3,143 GWh in 2012, consistent with 2011. Revenue increased to $306 million in 2012 from $296 million in 2011.

The following table compares the composition of FortisBC Electric's 2012 and 2011 revenue and electricity sales by customer class.

FortisBC Electric
Revenue and Electricity Sales by Customer Class

	Revenue (%)		**GWh Sales (%)**	
	2012	2011	**2012**	2011
Residential	**43.9**	43.7	**38.8**	40.1
Commercial	**21.1**	22.8	**23.2**	22.4
Wholesale	**20.3**	19.7	**28.7**	28.5
Industrial	**7.1**	7.4	**9.3**	9.0
Other [(1)]	**7.6**	6.4	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

[(1)] *Includes revenue from sources other than from the sale of electricity, including revenue of FortisBC Pacific Holdings associated with non-regulated operating, maintenance and management services*

Generation and Power Supply

FortisBC Inc. meets the electricity supply requirements of its customers through a mix of its own generation and power purchase contracts. FortisBC Inc. owns four regulated hydroelectric generating plants on the Kootenay River with an aggregate capacity of 223 MW, which provide approximately 45% of the Company's energy needs and 30% of its peak capacity needs. FortisBC Inc. meets the balance of its requirements through a portfolio of long-term and short-term PPAs. Since 1998 11 of the Company's 15 hydroelectric generation units have been subject to a life-extension and upgrade program, which substantially concluded in 2011.

FortisBC Inc.'s four hydroelectric generating facilities are governed by the CPA. The CPA is a multi-party agreement that enables the five separate owners of eight major hydroelectric generating plants, with a combined capacity of 1,565 MW and located in relatively close proximity to each other, to coordinate the operation and dispatch of their generating plants.

The following table lists the plants and their respective capacity and owner.

Plant	Capacity (MW)	Owners
Canal Plant	580	BC Hydro
Waneta Dam	493	Teck Metals and BC Hydro
Kootenay River System	223	FortisBC Inc.
Brilliant Dam and Expansion	269	BPC and BEPC
Total	**1,565**	

BPC, BEPC, Teck Metals and FortisBC Inc. are collectively defined in the CPA as the Entitlement Parties. 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 facilities, each of the Entitlement Parties is contractually entitled to a fixed annual entitlement of capacity and energy from BC Hydro, which is currently based on 50-year historical water flows. The Entitlement Parties receive their defined entitlements irrespective of actual water flows to the Entitlement Parties' generating plants and are, accordingly, insulated from the risk of water availability. Should the CPA be terminated, the output of FortisBC Inc.'s Kootenay River system plants would, with the water and storage authorized under its existing licences and on a long-term average, be approximately the same power output as FortisBC Inc. receives under the CPA. The CPA does not affect FortisBC Inc.'s ownership of its physical generation 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.

The majority of FortisBC Inc.'s remaining electricity supply is acquired through long-term power purchase contracts, consisting of the following:

i. a 149-MW long-term PPA with BPC terminating in 2056 (Brilliant PPA);
ii. a 200-MW PPA with BC Hydro terminating in 2013 (BC Hydro PPA);
iii. a capacity and energy purchase agreement with Brilliant Corporation from 2013 through 2017 (Brilliant Expansion Capacity and Energy Purchase Agreement);
iv. a number of small power purchase contracts with independent power producers;
v. spot market and contracted capacity purchases; and
vi. a 40-year agreement to purchase capacity from the Waneta Expansion upon completion of construction, which is expected in spring 2015 (WECA).

The majority of the above purchase contracts have been accepted by the BCUC and prudently incurred costs thereunder flow through to customers through FortisBC Inc.'s electricity rates.

Brilliant PPA
Under the Brilliant PPA, FortisBC Inc. has agreed to purchase from BPC, on a long-term basis: (i) the Entitlement allocated to the Brilliant hydroelectric plant; and (ii) after the expiration of the CPA, the actual electrical output generated by the Brilliant hydroelectric plant. While the total entitlement is 985,000 MWh, FortisBC Inc. does not purchase the approximate 60,000 MWh of regulated flow upgrade entitlement. However, FortisBC Inc. has recently entered into another agreement with CPC for this energy over a five-year period, as discussed below. The Brilliant PPA uses a take-or-pay contract structure which requires that FortisBC Inc. pay for the Brilliant hydroelectric plant's entitlement, irrespective of whether FortisBC Inc. actually takes it. FortisBC Inc. does not foresee any circumstances under which the Company would be required to pay for power that it does not require. During the first 30 years of the Brilliant PPA term, FortisBC Inc. pays to BPC an amount that covers the operation and maintenance costs of the Brilliant hydroelectric 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 hydroelectric plant and then-prevailing operating costs will be made to the amounts payable by FortisBC Inc. The Brilliant PPA provided FortisBC Inc. with approximately 27% of its energy requirements in 2012.

BC Hydro PPA
FortisBC Inc. is a party to the BC Hydro PPA, which provides the Company 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 12% of FortisBC Inc.'s energy requirements in 2012. The Company and BC Hydro are currently in negotiations regarding the renewal or replacement of the agreement for an additional 20-year term.

Brilliant Expansion Capacity and Energy Purchase Agreement
In November 2012 FortisBC Inc. entered into an agreement to purchase capacity and energy from 2013 through 2017 from CPC acting on behalf of Brilliant Corporation. The agreement was accepted by the BCUC in December 2012. The agreement allows FortisBC Inc. to purchase CPC's unused CPA entitlements from the Brilliant hydroelectric plant and the Brilliant hydroelectric expansion plant, including the 60,000 MWh from the Brilliant hydroelectric plant that is not included in the Brilliant PPA. The agreement is for a total of 78,500 MWh and is forecasted to provide 2% of FortisBC Inc.'s energy requirements in 2013.

Small Power Purchase Contracts
FortisBC Inc. has a number of small power purchase contracts with independent power producers, which collectively provided approximately 1% of the Company's energy supply requirements in 2012. The majority of these contracts have been accepted by the BCUC.

Spot Market and Contracted Capacity Purchases
During 2012 FortisBC Inc. 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 through to February 2016 to assist in mitigating risks of market volatility and availability.

WECA
In November 2011 FortisBC Inc. executed the WECA. The form of the WECA was originally accepted for filing by the BCUC in September 2010 and allows FortisBC Inc. to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected in spring 2015. The executed version of the WECA was submitted to the BCUC in November 2011. In May 2012 the BCUC determined that the executed agreement is in the public interest and a hearing was not required. The Waneta Expansion is included in the CPA and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing hydrologic risk associated with the project. The energy, approximately 630 GWh on an annual basis, and associated capacity required to deliver such energy for the Waneta Expansion, will be sold to BC Hydro under a long-term energy purchase agreement. The surplus capacity, equal to 234 MW on an average annual basis, will be sold to FortisBC Inc. over 40 years under the WECA. The total amount expected to be paid by FortisBC Inc. to the Waneta Partnership over the term of the WECA is approximately $2.9 billion. The agreement has been accepted for filing as an energy supply contract and FortisBC Inc. has been directed by the BCUC to develop a rate-smoothing proposal as part of a separate submission or as part of FortisBC Inc.'s next revenue requirements application. For additional information, refer to Section 3.4 of this 2012 Annual Information Form.

Legal Proceedings

The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC Inc. dated August 2, 2005. The Government of British Columbia has now disclosed that its claim includes approximately $15 million in damages as well as pre-judgment interest, but that it has not fully quantified its damages. In addition, private landowners have filed separate writs and statements of claim dated August 19, 2005 and August 22, 2005 in relation to the same matter which claims have now been settled. FortisBC Inc. and its insurers continue to defend the claim by the Government of British Columbia. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the Corporation's 2012 Audited Consolidated Financial Statements.

The Government of British Columbia filed a claim in the British Columbia Supreme Court in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which includes FortisBC Inc., use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $15 million. While FortisBC Inc. has not been served, the utility has retained counsel and has notified its insurers. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the Corporation's 2012 Audited Consolidated Financial Statements.

Human Resources

As at December 31, 2012, FortisBC Inc. had 542 full-time equivalent employees. The organized employees of FortisBC Inc. are represented by the IBEW, Local 213, and COPE, Local 378. The collective agreement between the Corporation and IBEW expired on January 31, 2013. IBEW represents employees in specified occupations in the areas of generation and T&D.

There are two collective agreements between FortisBC Inc. and COPE. For the first COPE collective agreement representing employees in specified occupations in the areas of administration and operations support, a new agreement came into effect on November 2, 2012 and expires on December 31, 2013. The second COPE collective agreement representing customer service employees expires on March 31, 2014.

3.2.3 *Newfoundland Power*

Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving more than 251,000 customers, or 87%, of the province's electricity consumers in approximately 600 communities. Newfoundland Power met a peak demand of 1,241 MW in 2012. The balance of the population is served by Newfoundland's other electric utility, Newfoundland Hydro, which also serves several larger industrial customers. Newfoundland Power owns and operates approximately 11,400 kilometres of T&D lines.

Market and Sales

Annual electricity sales increased to 5,652 GWh in 2012 from 5,553 GWh in 2011. Revenue increased to $581 million in 2012 from $573 million in 2011.

The following table compares the composition of Newfoundland Power's 2012 and 2011 revenue and electricity sales by customer class.

Newfoundland Power
Revenue and Electricity Sales by Customer Class

	Revenue [(1)] **(%)**		**GWh Sales** [(1)] **(%)**	
	2012	2011	**2012**	2011
Residential	**60.1**	60.4	**60.9**	61.3
Commercial	**36.2**	36.0	**39.1**	38.7
Other [(2)]	**3.7**	3.6	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Revenue and electricity sales reflect weather-adjusted values pursuant to Newfoundland Power's weather normalization reserve.*
(2) *Includes revenue from sources other than from the sale of electricity, including revenue deferrals.*

Power Supply

Approximately 93% of Newfoundland Power's energy requirements are purchased from Newfoundland Hydro. The principal terms of the supply arrangements with Newfoundland Hydro are regulated by the PUB on a basis similar to that upon which Newfoundland Power's service to its customers is regulated.

The purchased power rate structure is the basis upon which Newfoundland Hydro charges Newfoundland Power for purchased power and includes charges for both demand and energy purchased. The demand charge is based on applying a rate to the peak-billing demand for the most-recent winter season. The energy charge is a two-block charge with a higher second-block charge set to reflect Newfoundland Hydro's marginal cost of generating electricity.

Newfoundland Power operates 29 small generating facilities, which generate approximately 7% of the electricity sold by the Company. Newfoundland Power's hydroelectric generating plants have a total capacity of 97 MW. The diesel plants and gas turbines have a total capacity of approximately 7 MW and 37 MW, respectively.

Legal Proceedings

The City of St. John's has given formal notice of its intention to terminate Newfoundland Power's rights to use the Mobile River watershed for the generation of electricity. The effective date of the notice to terminate the lease was March 1, 2009. The Company held these rights under a lease dated November 23, 1946, which was amended by an agreement dated October 21, 1949. The two hydroelectric generating plants affected by the lease have a combined capacity of approximately 12 MW and generate annual production of 49 GWh, representing less than 1% of the Company's total energy requirements. To exercise the termination provision of the lease, the City of St. John's is required to pay to the Company the value of all works and erections employed in the generation and transmission of electricity using the water of the Mobile River watershed. In accordance with the terms of the lease, an arbitration panel was appointed in 2008 for the purpose of determining the value of the affected assets. In March 2009 the panel issued a ruling on certain preliminary questions. A majority of the panel ruled that termination of the lease will not be effective until payment to the Company of the value of the assets, and that the value of the payment is to be based on a valuation of the assets as a going concern, including the land and water rights.

The City of St. John's applied to the Supreme Court of Newfoundland and Labrador to have the preliminary ruling of the arbitration panel set aside. In November 2010 the Supreme Court issued a decision dismissing the City's application. In December 2010 the City of St. John's appealed the Supreme Court's decision to the Newfoundland and Labrador Court of Appeal. In March 2013 the Court of Appeal allowed the City's appeal, set aside the preliminary ruling of the arbitration panel and determined that the assets to be appraised under the lease are limited to the physical works and erections, not including land and water rights. Newfoundland Power is considering its options with respect to the Court of Appeal's decision.

Human Resources

As at December 31, 2012, Newfoundland Power had 653 full-time equivalent employees, of which approximately 56% were members of bargaining units represented by IBEW, Local 1620.

The Company has two collective agreements governing its union employees represented by IBEW, Local 1620. One bargaining unit is composed predominately of clerical employees and the other predominately of skilled trades and outside workers. Both collective agreements expire on September 30, 2014.

3.2.4 *Other Canadian Electric Utilities*

Other Canadian Electric Utilities are comprised of the operations of Maritime Electric and FortisOntario.

<u>Maritime Electric</u>
The Corporation, through FortisWest, holds all of the common shares of Maritime Electric. Maritime Electric is an integrated electric utility that directly supplies approximately 76,000 customers, constituting approximately 90% of electricity consumers on PEI. Maritime Electric purchases most of the energy it distributes to its customers from NB Power, a New Brunswick Crown corporation, through various energy purchase agreements. The Company also purchases energy from Island-based wind-powered generation owned by the PEI Energy Corporation, a provincial Crown corporation. Maritime Electric's electricity system is connected to the mainland power grid via two submarine cables between PEI and New Brunswick, which are leased from the Government of PEI. Maritime Electric owns and operates generating plants with a combined capacity of 150 MW on PEI and met a peak demand of 230 MW in 2012. Maritime Electric owns and operates approximately 5,500 kilometres of T&D lines.

<u>FortisOntario</u>
The Corporation's wholly owned regulated utility investments in Ontario, collectively FortisOntario, provide integrated electric utility service to approximately 64,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations are comprised of Canadian Niagara Power, Cornwall Electric and Algoma Power. In April 2012

FortisOntario exercised its option to purchase all of the assets previously leased by the Company under an operating lease agreement with the City of Port Colborne for the purchase option price of approximately $7 million. The exercise of the purchase option, which qualifies as a business combination, provides ownership and legal title to all of the assets, including equipment, real property and distribution assets, which constitute the electricity distribution system in Port Colborne. FortisOntario also owns a 10% interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies serving approximately 38,000 customers.

FortisOntario met a combined peak demand of 253 MW in 2012. FortisOntario owns and operates approximately 3,300 kilometres of T&D lines.

Market and Sales

Annual electricity sales were 2,381 GWh in 2012 compared to 2,366 GWh in 2011. Revenue was $353 million in 2012 compared to $339 million in 2011.

The following table compares the composition of Other Canadian Electric Utilities' 2012 and 2011 revenue and electricity sales by customer class.

Other Canadian Electric Utilities Revenue and Electricity Sales by Customer Class				
	Revenue (%)		**GWh Sales (%)**	
	2012	2011	**2012**	2011
Residential	**43.6**	43.4	**43.1**	43.2
Commercial and Industrial	**52.2**	52.3	**56.6**	56.2
Other (1)	**4.2**	4.3	**0.3**	0.6
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes revenue from sources other than from the sale of electricity*

Power Supply

Maritime Electric

Maritime Electric purchased 84% of the electricity required to meet its customers' needs from NB Power in 2012. The balance was met through the purchase of wind energy produced on PEI by stations owned by the PEI Energy Corporation and from Company-owned on-Island generation. Maritime Electric's on-Island generation facilities are used primarily for peaking, submarine-cable loading issues and emergency purposes.

Maritime Electric has two take-or-pay contracts for the purchase of either energy or capacity. In 2010 the Company signed a five-year take-or-pay contract with NB Power covering the period March 1, 2011 through February 29, 2016. The contract includes fixed pricing for the entire five-year period. The other take-or-pay contract, which is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on an international power line into the United States, expires in November 2032.

Maritime Electric has entitlement to approximately 4.7% of the output from Point Lepreau for the life of the unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital and operating costs of the unit. A major refurbishment of Point Lepreau that began in 2008 was completed and the station returned to service in November 2012. The refurbishment is expected to extend the facility's estimated life an additional 27 years.

In November 2010 Maritime Electric signed the PEI Energy Accord with the Government of PEI. The PEI Energy Accord covers the period from March 1, 2011 through February 29, 2016. Under the PEI Energy Accord, electricity costs for a typical customer were lowered approximately 14% effective March 1, 2011 and electricity rates were frozen until February 28, 2013. In December 2012 the *Accord Continuation Act* was enacted, which sets out the inputs, rates and other terms for the continuation of the PEI Energy Accord for three years covering the period March 1, 2013 through February 29, 2016. Over the three-year period, increases in electricity costs for a typical residential customer have been set at 2.2% annually and Maritime Electric's allowed ROE has been capped at 9.75% each year. Under the terms of the *Accord Continuation Act* and the PEI Energy Accord, the Government of PEI assumed, effective March 1, 2011, responsibility for the cost of incremental replacement energy and monthly operating and maintenance costs related to Point Lepreau during its refurbishment period, which ended in fall 2012.

The *Renewable Energy Act* (PEI) requires Maritime Electric to supply 15% of its annual energy sales from renewable energy sources. In 2012 approximately 15% of Maritime Electric's annual energy sales requirement was supplied by renewable energy.

FortisOntario

The power requirements of FortisOntario's service areas are provided from various sources. Canadian Niagara Power purchases its power requirements for Fort Erie and Port Colborne from IESO. Canadian Niagara Power purchases approximately 94% of energy requirements for Gananoque through monthly energy purchases from Hydro One and the remaining 6% is purchased, through the Hydroelectric Contract Initiative, from the five hydroelectric generating plants of the Fortis Generation East Partnership, effective July 1, 2012. Prior to July 1, 2012, the five hydroelectric generating plants were owned by Fortis Properties. Algoma Power purchases 100% of its energy from IESO.

Under the Standard Supply Code of the OEB, Canadian Niagara Power and Algoma Power are obliged to provide Standard Service Supply to all its customers who do not choose to contract with an electricity retailer. This energy is provided to customers at either regulated or market prices.

Cornwall Electric purchases substantially all of its power requirements from Hydro-Québec Energy Marketing under two fixed-term contracts. The first contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per year. Both contracts expire in December 2019.

Human Resources

As at December 31, 2012, Maritime Electric had 178 full-time equivalent employees, of which approximately 70% were represented by IBEW, Local 1432. The current collective agreement expires December 31, 2013.

As at December 31, 2012, FortisOntario had 196 full-time equivalent employees, of which approximately 59% were represented by CUPE, Local 1371, in Cornwall; IBEW, Local 636, in the Niagara region; IBEW, Local 636, in Gananoque; and Power Workers Union, a CUPE affiliate as CUPE, Local 1000, in the Algoma region. The expiry dates of the collective agreements are April 30, 2016; February 29, 2016; July 31, 2016; and December 31, 2016, respectively.

3.3 Regulated Electric Utilities - Caribbean

Regulated Electric Utilities - Caribbean operations are comprised of Caribbean Utilities and Fortis Turks and Caicos.

Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 27,000 customers. The Company met a peak demand of approximately 96 MW in 2012. Caribbean Utilities owns and operates approximately 705 kilometres of T&D lines and 25 kilometres of submarine cable. Fortis holds an approximate 60% (December 31, 2011 - 60%) controlling ownership interest in the utility. Caribbean Utilities is a public company traded on the TSX (TSX:CUP.U).

Fortis Turks and Caicos is comprised of FortisTCI, Atlantic Equipment & Power (Turks and Caicos) Ltd. and TCU, which are indirect wholly owned subsidiaries of Fortis. In August 2012 FortisTCI acquired TCU for an aggregate purchase price of approximately $13 million (US$13 million), inclusive of debt assumed of $5 million (US$5 million).

Each of the Fortis Turks and Caicos utilities is an integrated electric utility and, combined, serve approximately 12,000 customers, or 98% of electricity consumers, in the Turks and Caicos Islands. The utilities met a combined peak demand of approximately 35 MW in 2012. Fortis Turks and Caicos owns and operates approximately 600 kilometres of T&D lines. Fortis Turks and Caicos is the principal distributor of electricity in the Turks and Caicos Islands pursuant to 50-year licences that expire in 2036 and 2037.

Market and Sales

Annual electricity sales were 728 GWh in 2012 compared to 918 GWh in 2011. Revenue was $273 million in 2012 compared to $305 million in 2011. The decrease in annual electricity sales and revenue was largely due to the expropriation of Belize Electricity by the GOB in June 2011 and the consequential loss of control resulting in the discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011. For further information refer to the "Expropriated Assets" section that follows.

The following table compares the composition of Regulated Electric Utilities - Caribbean's revenue and electricity sales by customer class for the years ended 2012 and 2011.

Regulated Electric Utilities - Caribbean [(1)]
Revenue and Electricity Sales by Customer Class

	Revenue (%)		GWh Sales (%)	
	2012	2011	**2012**	2011
Residential	**44.7**	46.6	**42.4**	45.5
Commercial and Industrial	**54.2**	52.5	**57.6**	54.5
Other [(2)]	**1.1**	0.9	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Comprised of Caribbean Utilities and Fortis Turks and Caicos, and Belize Electricity up to June 20, 2011*
(2) *Includes revenue from sources other than from the sale of electricity*

Power Supply

Caribbean Utilities relies upon in-house diesel-powered generation to produce electricity for Grand Cayman. Grand Cayman has neither hydroelectric potential nor inherent thermal resources and the Company must rely upon diesel fuel imported to Grand Cayman primarily from refineries in the Caribbean and the Gulf of Mexico. The Company has an installed generating capacity of approximately 150 MW.

Caribbean Utilities has primary and secondary fuel supply contracts entered into in 2012, with renewal options in 2014. Caribbean Utilities also entered into a five-year contract for the supply of lube oil. These contracts enable Caribbean Utilities to purchase fuel and lube oil from the suppliers on what the Company believes to be competitive terms and pricing. Both the fuel and lube oil contracts include disaster recovery and business continuity plans in the event of foreseeable disruptions to supplies to reduce the impact on Caribbean Utilities' operations.

Fortis Turks and Caicos relies upon in-house diesel-powered generation, which has a combined generating capacity of 76 MW, to produce electricity for its customers.

FortisTCI has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

Expropriation of Shares in Belize Electricity

On June 20, 2011, the GOB enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. Consequent to the deprivation of control over the operations of the utility, the Corporation discontinued the consolidation method of accounting for Belize Electricity, as of June 20, 2011, and classified the book value, including foreign exchange impacts, of the expropriated investment as a long-term other asset on the consolidated balance sheet.

In October 2011 Fortis commenced an action in the Belize Supreme Court with respect to challenging the constitutionality of the expropriation of the Corporation's investment in Belize Electricity. Fortis commissioned an independent valuation of its expropriated investment and submitted its claim for compensation to the GOB in November 2011. The book value of the long-term other asset is below fair value as at the date of expropriation as determined by the independent valuators. The GOB also commissioned a valuation of Belize Electricity which is significantly lower than both the fair value determined under the Corporation's valuation and the book value of the long-term other asset. While Fortis and representatives and third-party consultants of the GOB have held discussions in 2012 on differences in assumptions used in the valuations, there have been no discussions on any compensation settlement amount.

In July 2012 the Belize Supreme Court dismissed the Corporation's claim of October 2011. Also in July 2012, Fortis filed its appeal of the above-noted trial judgment in the Belize Court of Appeal. The appeal was heard in October 2012 and a decision is pending. Any decision of the Belize Court of Appeal may be appealed to the Caribbean Court of Justice, the highest court of appeal available for judicial matters in Belize.

Fortis believes it has a strong, well-positioned case before the Belize Courts supporting the unconstitutionality of the expropriation. There exists, however, a reasonable possibility that the outcome of the litigation may be unfavourable to the Corporation and the amount of compensation otherwise to be paid to Fortis under the legislation expropriating Belize Electricity could be lower than the book value of its expropriated investment in Belize Electricity. The book value was $104 million, including foreign exchange impacts, as at December 31, 2012 (December 31, 2011 - $106 million). If the expropriation is held to be unconstitutional, it is not determinable at this time as to the nature of the relief that would be awarded to Fortis, for example: (i) the ordering of the return of the shares to Fortis and/or award of damages; or (ii) the ordering of compensation to be paid to Fortis for the unconstitutional expropriation of the shares. Based on presently available information, the long-term other asset is not deemed impaired as at December 31, 2012. Fortis will continue to assess for impairment each reporting period based on evaluating the outcomes of court proceedings and/or compensation settlement negotiations, if any. As well as continuing the constitutional challenge of the expropriation, Fortis is also pursuing alternative options for obtaining fair compensation, including compensation under the Belize/UK Bilateral Investment Treaty. For further information on the expropriation of Belize Electricity, refer to the "Business Risk Management – Expropriation of Shares in Belize Electricity" section of the Corporation's MD&A.

Human Resources

As at December 31, 2012, Regulated Electric Utilities - Caribbean employed 341 full-time equivalent employees. The 190 employees at Caribbean Utilities and 151 employees at Fortis Turks and Caicos are non-unionized.

3.4 Non-Regulated - Fortis Generation

The following table summarizes the Corporation's non-regulated generation assets by location.

Fortis Generation Non-Regulated Generation Investments			
Location	**Plants**	**Fuel**	**Capacity (MW)**
Belize	3	hydro	51
Ontario	7	hydro, thermal	13
Central Newfoundland *(1)*	2	hydro	36
British Columbia *(2)*	1	hydro	16
Upstate New York	4	hydro	23
Total	**17**		**139**

(1) *The two central Newfoundland facilities that were owned by the Exploits Partnership were expropriated by the Government of Newfoundland and Labrador in December 2008. Effective February 12, 2009, the Corporation discontinued the consolidation method of accounting for its investment in central Newfoundland.*

(2) *Once completed, the Waneta Expansion will provide an additional 335 MW of hydroelectric generating capacity in British Columbia.*

The Corporation's non-regulated generation operations consist of its 100% ownership interest in each of BECOL, FortisOntario and FortisUS Energy, as well as non-regulated generation assets owned by FortisBC Inc. and by Fortis through its 51% controlling ownership interest in the Waneta Partnership. Effective July 1, 2012, the legal ownership of the six hydroelectric generating facilities in eastern Ontario was transferred from Fortis Properties to Fortis Generation East Partnership, a limited liability partnership directly held by Fortis. The investment in the Exploits Partnership is held by Fortis Properties.

Non-regulated generation operations in Belize consist of the 25-MW Mollejon, 7-MW Chalillo and 19-MW Vaca hydroelectric generating facilities. All of the output of these facilities is sold to Belize Electricity under 50-year PPAs expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary BECOL under a franchise agreement with the GOB. In October 2011 the GOB purportedly amended the Constitution of Belize to require majority government ownership of three public utility providers, including Belize Electricity, but excluding BECOL. The GOB has also indicated it has no intention to expropriate BECOL. Fortis continues to control and consolidate the financial statements of BECOL.

Non-regulated generation operations of FortisOntario are comprised of the operation of a 5-MW gas-powered cogeneration plant in Cornwall. All thermal energy output of this plant is sold to external third parties, while the electricity output is sold to Cornwall Electric. Fortis Generation East Partnership owns and operates six small hydroelectric generating facilities in eastern Ontario with a combined capacity of 8 MW. The electricity produced from these facilities is sold to the Ontario Power Association, via the Hydroelectric Contract Initiative, under fixed-price contracts.

Fortis Properties has a non-regulated generation investment in central Newfoundland that is held through the Company's direct 51% interest in the Exploits Partnership. Through the Exploits Partnership, 36 MW of additional capacity was developed and installed at two of Abitibi's hydroelectric generating facilities in central Newfoundland. Output from the generating facilities is being sold to Newfoundland Hydro under a 30-year PPA expiring in 2033. Effective February 2009, the Corporation discontinued the consolidation method of accounting for these operations, necessitated by the actions of the Government of Newfoundland and Labrador related to its expropriation of the hydroelectric assets and water rights of the Exploits Partnership. Refer to the "Expropriated Assets" section that follows.

The non-regulated generation operations of FortisBC Inc. include the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia that sells its entire output to BC Hydro under a contract set to expire in the fourth quarter of 2013. Non-regulated generation operations in British Columbia also include the Corporation's 51% controlling ownership interest in the Waneta Partnership, with CPC/CBT holding the remaining 49% interest. Fortis will operate and maintain the non-regulated investment when the facility comes into service, which is expected in spring 2015. The Waneta Partnership commenced construction of the $900 million, 335-MW Waneta Expansion in late 2010, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia. Construction progress is going well and the project is currently on schedule and on budget. Approximately $436 million in total has been spent on the Waneta Expansion since construction began in late 2010, with $192 million spent in 2012. Major construction activities on-site during 2012 included the completion of the excavation of the intake, powerhouse and power tunnels. Approximately $227 million is expected to be spent in 2013, with key project activities including completion of the powerhouse structural steel and building envelope; excavation of the intake approach channel; construction of the intake and tailrace structures; and removal of rock plug. In addition, installation of the stationary imbedded turbine and generator components will continue. For additional information refer to Section 3.2.2 of this 2012 Annual Information Form.

Through FortisUS Energy, an indirectly wholly owned subsidiary, the Corporation owns and operates four hydroelectric generating facilities in Upstate New York with a combined capacity of approximately 23 MW operating under licences from FERC. All four hydroelectric generating facilities sell energy at market rates through purchase agreements with Niagara Mohawk Power Corporation.

Market and Sales

Annual energy sales from non-regulated generation assets were 306 GWh in 2012 compared to 389 GWh in 2011. Revenue was $31 million in 2012 compared to $34 million in 2011.

The following table compares the composition of Fortis Generation's 2012 and 2011 revenue and energy sales by location.

Fortis Generation Revenue and Energy Sales by Location				
	Revenue (%)		**GWh Sales (%)**	
	2012	2011	**2012**	2011
Belize	**70.2**	65.8	**65.1**	60.2
Ontario	**13.0**	13.3	**12.9**	12.0
Central Newfoundland (1)	**4.5**	4.1	**-**	-
British Columbia	**6.8**	6.7	**11.4**	10.3
Upstate New York	**5.5**	10.1	**10.6**	17.5
Total	**100.0**	100.0	**100.0**	100.0

(1) *Reflects the discontinuance of the consolidation method of accounting for the financial results of the operations in central Newfoundland, effective February 12, 2009*

Expropriated Assets

In December 2008 the Government of Newfoundland and Labrador expropriated Abitibi's hydroelectric assets and water rights in Newfoundland, including those of the Exploits Partnership. The newsprint mill in Grand Falls-Windsor closed on February 12, 2009, subsequent to which the day-to-day operations of the Exploits Partnership's hydroelectric generating facilities were assumed by Nalcor Energy, a Crown corporation, acting as an agent for the Government of Newfoundland and Labrador with respect to expropriation matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi in the province. The loss of control over cash flows and operations required Fortis to cease consolidation of the Exploits Partnership, effective February 12, 2009. Discussions between Fortis Properties and Nalcor Energy with respect to expropriation matters are ongoing.

Human Resources

As at December 31, 2012, Fortis Generation employed 39 full-time equivalent employees, none of whom participate in a collective agreement.

3.5 Non-Regulated - Fortis Properties

As a wholly owned subsidiary of Fortis, Fortis Properties is the Corporation's vehicle for non-utility diversification and growth. The Company owns and operates 23 hotels, comprised of more than 4,400 rooms, in eight Canadian provinces, and approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada. Fortis Properties is currently constructing a $47 million 12-storey office building in downtown St. John's, Newfoundland. The building will feature a gross area of 157,000 square feet of Class A office space. Construction is expected to be completed by the end of 2013 or early in 2014.

Revenue was $242 million in 2012 compared to $231 million in 2011. In 2012 Fortis Properties derived approximately 28% of its revenue from real estate operations and 72% of its revenue from hotel operations. Fortis Properties derived approximately 43% of its 2012 operating income from real estate operations and 57% from hotel operations.

Fortis Properties' Real Estate Division is anchored by high-quality tenants under long-term leases. The Real Estate Division ended 2012 with 91.9% occupancy, compared to 93.2% occupancy at the end of 2011. In contrast, the average national occupancy rate was 91.5% at the end of 2012, compared to 91.9% at the end of 2011.

The following table sets out the office and retail properties owned by Fortis Properties.

Fortis Properties
Office and Retail Properties

Property	**Location**	**Type of Property**	**Gross Lease Area** *(square feet 000's)*
Fort William Building	St. John's, NL	Office	188
Cabot Place I	St. John's, NL	Office	136
TD Place	St. John's, NL	Office	99
Fortis Building	St. John's, NL	Office	83
Multiple Office	St. John's, NL	Office and Retail	75
Millbrook Mall	Corner Brook, NL	Retail	118
Fraser Mall	Gander, NL	Retail	99
Marystown Mall	Marystown, NL	Retail	92
Fortis Tower	Corner Brook, NL	Office	69
Maritime Centre	Halifax, NS	Office and Retail	565
Brunswick Square	Saint John, NB	Office and Retail	511
Kings Place	Fredericton, NB	Office and Retail	291
Blue Cross Centre	Moncton, NB	Office and Retail	325
Delta Regina	Regina, SK	Office	52
Total			**2,703**

Revenue per available room at the Hospitality Division of Fortis Properties was $80.00 for 2012 as compared to $78.76 for 2011. Excluding the impacts of the StationPark Hotel acquired October 2012 and the Hilton Suites Hotel acquired October 2011, revenue per available room increased to $78.80 for 2012 from $78.48 for 2011. The increase was the result of a 1.5% increase in average daily room rate, partially offset by a 1.1% decrease in hotel occupancy. Excluding the impact of the two hotel acquisitions, the average daily room rate increased to $129.45 for 2012 from $127.59 for 2011, while the average occupancy for 2012 was 60.9%, down from the 61.5% achieved in 2011.

The hotels owned and managed by Fortis Properties are summarized as follows.

Fortis Properties
Hotels

Hotels	**Location**	**Number of Guest Rooms**	**Conference Facilities** *(000's square feet)*
Delta St. John's	St. John's, NL	403	21
Holiday Inn St. John's	St. John's, NL	252	12
Sheraton Hotel Newfoundland	St. John's, NL	301	18
Mount Peyton	Grand Falls-Windsor, NL	148	5
Greenwood Inn Corner Brook	Corner Brook, NL	102	5
Four Points by Sheraton Halifax	Halifax, NS	177	12
Holiday Inn Sydney - Waterfront [(1)]	Sydney, NS	152	6
Delta Brunswick	Saint John, NB	254	18
Holiday Inn Kitchener - Waterloo	Kitchener-Waterloo, ON	184	13
Holiday Inn Peterborough	Peterborough, ON	153	7
Holiday Inn Sarnia	Point Edward, ON	216	11
Holiday Inn Cambridge	Cambridge, ON	143	7
Holiday Inn & Suites Windsor	Windsor, ON	214	17
Greenwood Inn Calgary	Calgary, AB	210	9
StationPark Hotel [(2)]	London, ON	126	2
Holiday Inn Edmonton	Edmonton, AB	224	8
Greenwood Inn Winnipeg	Winnipeg, MB	213	8
Hilton Suites Winnipeg Airport	Winnipeg, MB	159	9
Holiday Inn Lethbridge	Lethbridge, AB	119	5
Holiday Inn Express and Suites Medicine Hat	Medicine Hat, AB	93	1
Best Western Medicine Hat	Medicine Hat, AB	122	-
Holiday Inn Express Kelowna	Kelowna, BC	190	5
Delta Regina	Regina, SK	274	24
Total		**4,429**	**223**

(1) In July 2012 the Delta Sydney was rebranded to Holiday Inn Sydney - Waterfront.
(2) Fortis Properties acquired the StationPark Hotel in October 2012.

Human Resources

As at December 31, 2012, Fortis Properties employed approximately 2,400 full-time equivalent employees, approximately 46% of whom are represented by unions listed in the following table.

Fortis Properties Unions			
Property	**Union**	**Expiry of Agreement**	**Number of Unionized Employees**
Holiday Inn St. John's	CAW	August 31, 2015	57
Delta St. John's	UFCW	December 31, 2016	250
Greenwood Inn Corner Brook [(1)]	CAW	March 11, 2013	44
East Side Mario's St. John's	CAW	July 31, 2013	95
Holiday Inn Sydney - Waterfront [(2)]	CAW	September 30, 2014	64
Delta Brunswick & Brunswick Square	USW	June 10, 2013	119
Delta Regina	CEP	May 31, 2014	172
St. John's Real Estate [(1)]	IBEW	April 17, 2013	8
Sheraton Hotel Newfoundland	CAW	March 31, 2015	190
Holiday Inn & Suites Windsor [(3)]	UFCW	April 30, 2013	46
Mount Peyton	UFCW	December 1, 2014	54
Total			**1,099**

[(1)] *Notice to bargain was received from the respective unions; however, collective bargaining has not commenced.*
[(2)] *In July 2012 the Delta Sydney was rebranded to Holiday Inn Sydney - Waterfront.*
[(3)] *Negotiations commenced in February 2013.*

4.0 REGULATION

The Corporation's utilities primarily operate under a cost of service methodology and are regulated by the regulatory body in its respective operating jurisdiction. With regulated utilities in seven different jurisdictions, Fortis has significant regulatory expertise.

For information with respect to the nature of regulation and material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities, refer to the "Regulatory Highlights" section of the Corporation's MD&A and to Note 2 of the Corporation's 2012 Audited Consolidated Financial Statements.

5.0 ENVIRONMENTAL MATTERS

The Corporation and its Canadian subsidiaries are subject to various federal, provincial and municipal laws, regulations and guidelines relating to the protection of the environment including, but not limited to, wildlife, water and land protection, emissions and the proper storage, transportation, recycling and disposal of hazardous and nonhazardous 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 their commencement.

Several key Canadian federal environmental laws and regulations affecting the operations of the Corporation's Canadian subsidiaries include, but are not limited to, the: (i) *Canadian Environmental Assessment Act;* (ii) *Canadian Environmental Protection Act*; (iii) *Transportation of Dangerous Goods Act and Regulations*; (iv) *Hazardous Products Act*; (v) *Canada Wildlife Act*; (vi) *Navigable Waters Protection Act*; (vii) *Canada National Parks Act*; (viii) *Fisheries Act;* (ix) *Canada Water Act;* (x) *National Emission Guidelines for Stationary Combustion Turbines;* (xi) *National Fire Code of Canada;* (xii) *Pest Control Products Act and Regulations;* (xiii) *PCB Regulations;* (xiv) *Canadian Species at Risk Act;* (xv) *Ozone Depleting Substances Regulations;* (xvi) *Indian Act;* (xvii) *International Rivers Improvement Act;* and (xviii) *Migratory Birds Convention Act.*

Environmental risks affecting the Corporation's utility operations include, but are not limited to: (i) hazards associated with the transportation, storage and handling of large volumes of fuel for fuel-powered electricity generating plants, including leeching of the fuel into the ground, nearby watershed areas and open waters; (ii) risk of spills or leaks of petroleum-based products, including PCB-contaminated oil, which are used in the cooling and lubrication of transformers, capacitors and other electrical equipment; (iii) risk of spills or releases into the environment arising from the improper transportation, storage, handling and disposal of other hazardous substances; (iv) GHG emissions, including natural gas and propane leaks and spills and emissions from the combustion of fuel required to generate electricity; (v) risk of fire; (vi) risk of disruption to vegetation; (vii) risk of contamination of soil and water near chemically treated poles; (viii) risk of disruption to fish, animals and their habitat as a result of the creation of artificial water flows and levels associated with hydroelectric water storage and utilization; and (ix) risk of responsibility for remediation of contaminated properties, whether or not such contamination resulted from the Corporation's utility operations.

There are many Canadian provincial and municipal laws, regulations and guidelines that address similar environmental risks as the federal laws, regulations and guidelines, but at a provincial or local level.

In British Columbia, the *Carbon Tax Act, Clean Energy Act, Greenhouse Gas Reduction (Cap and Trade) Act* and *Greenhouse Gas Reduction Targets Act* and anticipated cap-and-trade regulations specifically affect, or may potentially affect, the operations of the FortisBC Energy companies and FortisBC Electric.

The management of GHG emissions is the main environmental concern of the Corporation's Regulated Gas Utilities, primarily due to the uncertainties relating to new and emerging federal and provincial GHG laws, regulations and guidelines. While governmental policy direction is unfolding, it remains to be determined to what extent a GHG air emissions cap will impact these utilities. To help mitigate this uncertainty, the FortisBC Energy companies participate in sectoral and industry groups to monitor the development of emerging regulations. Involvement in stakeholder consultations by the

FortisBC Energy companies has occurred to ensure the perspective of the Companies is considered such that unnecessary prescriptive reporting requirements do not encumber existing asset integrity management processes that are in place to address operational risks around GHG emissions.

The Government of British Columbia's Energy Plan and GHG reduction targets present risks and opportunities to the FortisBC Energy companies and, to a lesser degree, FortisBC Electric. These government initiatives continue to place pressure on natural gas consumption and its contribution to GHG emissions. The *Greenhouse Gas Reduction Targets Act* mandates a public sector reduction in GHG emissions of 33% from 2007 levels by 2020. This is coupled with mandates for all new electricity generation to be net carbon neutral. Energy objectives under the *Clean Energy Act* aim to ensure electricity self-sufficiency for British Columbia by 2016. The *Clean Energy Act* also places a new focus on clean demand-side management measures and smart metering technologies. In 2008 the Government of British Columbia amended the *Utilities Commission Act* to require the BCUC to ensure that utilities undertake efficiency and conservation measures in their operations and to consider the Government of British Columbia's energy objectives in specified approval processes.

The energy and GHG emissions policies in British Columbia have created opportunities for FEI through incentives to expand FEI's deployment of renewable energy, such as biogas, and to expand its Energy Efficiency and Conservation Program. Additionally, the introduction of the *Carbon Tax Act* improves the competitive position of natural gas relative to other fossil fuels, as the tax is based on the amount of carbon dioxide equivalent emitted per unit of energy. Natural gas, therefore, has a lower tax rate than oil or coal products.

British Columbia is a participant in the Western Climate Initiative. The participants, consisting of several states and provinces, expect to implement a cap-and-trade program to reduce GHG emissions. The cap and trade program was expected to begin on January 1, 2012 but the Government of British Columbia has delayed the development of this regulatory initiative. FEI and FEVI are expected to be covered under the program. The specific details of which facilities will be covered under the program are dependent on the types of emissions and how individual facilities will be defined under cap-and-trade legislation. If implemented, the cap-and-trade program is expected to have a declining cap on emissions that all applicable facilities must meet, either by reducing emissions internally or by purchasing allowances from other facilities for release of GHG emissions over the capped amounts.

In 2011 the FortisBC Energy companies began reporting their GHG emissions pursuant to the reporting regulation under the *Greenhouse Gas Reduction (Cap and Trade) Act.* In addition, the FortisBC Energy companies continue to report their GHG emissions under Environment Canada's GHG Reporting Program. The FortisBC Energy companies have developed capabilities that will manage compliance requirements in the upcoming GHG emissions' trading environment. The Companies will also continue to monitor and assess emerging regulations, in particular, the offset and allowance regulations.

The impact of GHG emissions is lower at the Corporation's Canadian Regulated Electric Utilities because their primary business is the distribution of electricity. With respect to FortisAlberta, its operations involve only the distribution of electricity. Additionally, all in-house generating capacity at FortisBC Electric and about 70% at Newfoundland Power and most of the Corporation's non-regulated generating capacity is hydroelectric, a clean energy source. The 335-MW Waneta Expansion will be a clean renewable hydroelectric energy source when it comes into service in spring 2015. Only a small portion of in-house generation at Canadian Regulated Electric Utilities uses diesel fuel. There is no coal-fired generation within any of the Corporation's operations. The Corporation's Canadian Regulated Electric Utilities are indirectly impacted, however, by GHG emissions through the purchase of power generated by suppliers using combustible fuel. Such power suppliers are responsible for compliance with carbon dioxide emissions standards and the cost of compliance with such standards is generally flowed through to end-use consumers.

The *Renewable Energy Act* (PEI) and the recent PEI Energy Accord directly impact the long-term energy supply planning process for the province of PEI. The Act required Maritime Electric to source 15% of its annual energy sales from renewable sources by 2010, which the Company met in both 2011 and 2012. Under the PEI Energy Accord, Maritime Electric and the Government of PEI are committed to work collaboratively to increase electricity produced on PEI and sold to Maritime Electric from renewable energy sources, principally wind.

In 2011 Canada announced its decision to invoke its legal right to formally withdraw from the Kyoto Protocol. Canada is now negotiating a new international climate change treaty that could create binding GHG commitments for all major GHG emitters by 2015. It is uncertain as to what impact this process may have going forward.

While there are environmental laws, regulations and guidelines affecting the Corporation's operations in Grand Cayman and Turks and Caicos Islands, they are less extensive than the laws, regulations and guidelines in Canada. The United Kingdom's ratification of the United Nations Framework Convention on Climate Change and its Kyoto Protocol were extended to the Cayman Islands in 2007. This framework aims to reduce GHG emissions produced by certain industries. Specific details on the regulations implementing the protocol have yet to be released by the local government of the Cayman Islands and, accordingly, Caribbean Utilities is currently unable to assess the financial impact of compliance with the framework of the protocol.

All of the energy requirements of Caribbean Utilities and Fortis Turks and Caicos are sourced from in-house diesel-powered generation. Newly installed diesel generators at Caribbean Utilities and Fortis Turks and Caicos have incorporated improvements to generate electricity in a more efficient and environmentally friendly manner. Newly installed generators have also been designed to provide an increased output per gallon consumed than the older generators. The height of exhaust stacks have been increased and improved exhaust systems installed to maximize sound attenuation, and optimize exhaust plume dispersion thereby improving local air quality in accordance with what the utilities believe to be the best industry practice. The use of diesel oil versus heavy fuel oil also results in significantly lower levels of exhaust emissions. The utilities also purchase and store diesel fuel and/or lubricating oil in bulk thereby decreasing the environmental risks associated with fuel and/or oil handling. Investments have been made in containment areas for the bulk storage of diesel fuel which have been designed to prevent the fuel from coming into contact with soil or groundwater. Caribbean Utilities also uses an underground fuel pipeline for the delivery of fuel from suppliers' distribution terminals on the coast of Grand Cayman to the day-tank holding facilities at the Company's generating plant. The pipeline eliminates the need for road transport of fuel along coastline roads.

The key focus of the utilities is to provide reliable cost-effective service with full regard for the safety of employees and the public while operating in an environmentally responsible manner. A focus on safety and the environment is, therefore, an integral and continuing component of the Corporation's operating activities.

Each of the Corporation's utilities has an EMS, with the exception of Fortis Turks and Caicos which expects to complete the implementation of its EMS by the end of 2014. Environmental policies form the cornerstone of the EMS and outline the following commitments by each utility and its employees with respect to conducting business in a safe and environmentally responsible manner: (i) meet and comply with all applicable laws, legislation, policies, regulations and accepted standards of environmental protection; (ii) manage activities consistent with industry practice and in support of the environmental policies of all levels of government; (iii) identify and manage risks to prevent or reduce adverse consequences from operations, including preventing pollution and conserving natural resources; (iv) regular environmental monitoring and audits of the EMS and striving for continual improvement in environmental performance; (v) regularly set and review environmental objectives, targets and programs regularly; (vi) communicate openly with stakeholders including making available the utility's environmental policy and knowledge of environmental issues to customers, employees, contractors and the general public; (vii) support and participate in community based projects that focus on the environment; (viii) provide training for employees and those working on behalf of the utility to enable them to fulfill their duties in an environmentally responsible manner; and (ix) work with industry associations, government and other stakeholders to establish standards for the environment appropriate to the utility's business.

Through an EMS, documented procedures are in place to control activities that can affect the environment. Common elements of the utilities' EMSs include: (i) regular inspections of fuel and oil-filled equipment in order to identify and correct for potential spills, and spill response systems to ensure that all spills are addressed, and the associated cleanup is conducted in a prompt and environmentally responsible manner; (ii) GHG emissions management; (iii) procedures for handling, transporting, storing and disposing of hazardous substances, including chemically treated poles, asbestos, lead and mercury, where applicable; (iv) programs to mitigate fire-related incidents; (v) programs for the management and/or elimination of PCBs, where applicable; (vi) vegetation management programs; (vii) training and communicating of environmental policies to employees to ensure work is conducted in an environmentally responsible manner; (viii) review of work practices that affect the environment; (ix) waste management programs; (x) environmental emergency response procedures; (xi) environmental site assessments; and (xii) environmental incident reporting procedures. Additionally, in the case of Newfoundland Power and FortisBC Electric, the EMSs also address water control and dam structure, as well as hydroelectric generating facility operations and the impact of such on fish and the surrounding habitat.

The FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and FortisOntario have developed their respective EMSs consistent with the guidelines of ISO 14001, an internationally recognized standard for EMSs. Caribbean Utilities operates an EMS associated with its generation operations, which is ISO 14001 certified, and uses an EMS for its T&D operations, which is consistent with ISO 14001 guidelines. Fortis Turks and Caicos' EMS, when fully implemented, is also expected to be ISO 14001 certified. As part of their respective EMS, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor performance. External and/or internal audits of the EMSs are performed on a periodic basis. Based on audits last completed, the EMSs continue to be effective, properly implemented and maintained, and materially consistent with ISO 14001 guidelines.

Each of the Corporation's Canadian Regulated Electric Utilities that is a member of the CEA is an active participant in the CEA's Sustainable Electricity Program, which was launched in 2009. Participants in the program commit to continuous improvement of their environmental management and performance including reporting annually on environmental and other performance indicators.

In addition to the EMSs, various energy efficiency programs and initiatives, which help in reducing GHG emissions, are undertaken by the utilities or offered to customers.

Environmental risks associated with the Corporation's non-regulated generation operations are addressed in a similar manner as the Corporation's regulated electric utilities that operate in the same jurisdiction as the non-regulated generation operations.

The key environmental risks affecting the Corporation's hospitality and real estate operations include, but are not limited to: (i) asbestos and urea-formaldehyde contamination in buildings; (ii) release of ozone-depleting substances from air conditioning and refrigeration equipment; (iii) fuel tank leaks; and (iv) remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. Fortis Properties is committed to meeting the requirements of environmental standards related to its hospitality and real estate operations. In assessing properties being acquired, all must meet environmental standards, including, but not limited to, the appropriate federal, provincial and municipal standards for asbestos, fuel storage, urea-formaldehyde and chlorofluorocarbon-based refrigerants in air conditioning and refrigeration equipment. This process is also applied to existing properties, ensuring environmental compliance by all facilities.

The Corporation has asset-retirement obligations as disclosed in the notes to its 2012 Audited Consolidated Financial Statements. However, liabilities with respect to these asset-retirement obligations have not been recorded in the Corporation's 2012 Audited Consolidated Financial Statements, with the exception of approximately $3 million related to PCBs at FortisBC Electric, as they could not be reasonably estimated or were determined to be immaterial (including asset-retirement obligations associated with asbestos and chemically treated poles) to the Corporation's consolidated results of operations, cash flows or financial position. The utilities have ongoing programs to identify and replace transformers which are at risk of spillage of oil, and PCBs continue to be removed from service and safely disposed of in compliance with applicable laws and regulations.

Costs associated with environmental protection initiatives (including the development, implementation and maintenance of EMSs), compliance with environmental laws, regulations and guidelines, and environmental damage did not materially affect the Corporation's consolidated results of operations, cash flows or financial position during 2012 and, based on current laws, facts and circumstances, are not expected to have a material effect in 2013. Many of the above costs, however, are embedded in the utilities' operating, maintenance and capital programs and are, therefore, not readily identifiable. At the Corporation's regulated utilities, prudently incurred operating and capital costs associated with environmental protection initiatives, compliance with environmental laws, regulations and guidelines, and environmental damage are eligible for recovery in customer rates. Fortis believes that the Corporation and its subsidiaries are materially compliant with environmental laws and regulations applicable to them in the various jurisdictions in which they operate.

Oversight of environmental matters is performed at the subsidiary level with regular reporting of environmental matters to the respective subsidiary's Board of Directors.

For further information on the Corporation's environmental risk factors, refer to the "Business Risk Management - Environmental Risks" section of the Corporation's MD&A.

6.0 RISK FACTORS

For information with respect to the Corporation's significant business risks, refer to the "Business Risk Management" section of the Corporation's MD&A.

7.0 GENERAL DESCRIPTION OF SHARE CAPITAL STRUCTURE

The authorized share capital of the Corporation consists of the following:

(a) an unlimited number of Common Shares without nominal or par value;
(b) an unlimited number of First Preference Shares without nominal or par value; and
(c) an unlimited number of Second Preference Shares without nominal or par value.

As at March 21, 2013, the following Common Shares and First Preference Shares were issued and outstanding.

Share Capital	Issued and Outstanding	Votes per Share [(1)]
Common Shares	192,475,945	One
First Preference Shares, Series C	5,000,000	None
First Preference Shares, Series E	7,993,500	None
First Preference Shares, Series F	5,000,000	None
First Preference Shares, Series G	9,200,000	None
First Preference Shares, Series H	10,000,000	None
First Preference Shares, Series J	8,000,000	None

[(1)] *The First Preference Shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive, and whether such dividends have been declared.*

Subscription Receipts Offering

To finance a portion of the pending acquisition of CH Energy Group, Fortis sold 18.5 million Subscription Receipts at $32.50 each in June 2012 through a bought-deal offering underwritten by a syndicate of underwriters, realizing gross proceeds of approximately $601 million. The gross proceeds from the sale of the Subscription Receipts are being held by an escrow agent, pending satisfaction of closing conditions, including receipt of regulatory approvals, included in the agreement and plan of merger to acquire CH Energy Group. The Subscription Receipts began trading on the TSX on June 27, 2012 under the symbol "FTS.R".

Each Subscription Receipt will entitle the holder thereof to receive, on satisfaction of the Release Conditions, and without payment of additional consideration, one common share of Fortis and a cash payment equal to the dividends declared on Fortis common shares during the period from June 27, 2012 to the date of issuance of the common shares in respect of the Subscription Receipts to holders of record.

If the Release Conditions are not satisfied by June 30, 2013, or if the agreement and plan of merger relating to the acquisition of CH Energy Group is terminated prior to such time, holders of Subscription Receipts shall be entitled to receive from the escrow agent an amount equal to the full subscription price thereof plus their *pro rata* share of the interest earned on such amount. Closing of the acquisition of CH Energy Group subsequent to June 30, 2013 could result in the Corporation having to raise alternative capital to finance the transaction.

Dividend Policy

The following table summarizes the cash dividends declared per share for each of the Corporation's class of share for the past three years.

	Dividends Declared *(per share)*		
Share Capital	**2010** [(1)]	**2011**	**2012**
Common Shares	$1.41	$1.17	$1.21
First Preference Shares, Series C	$1.7031	$1.3625	$1.3625
First Preference Shares, Series E	$1.5313	$1.2250	$1.2250
First Preference Shares, Series F	$1.5313	$1.2250	$1.2250
First Preference Shares, Series G	$1.6406	$1.3125	$1.3125
First Preference Shares, Series H [(2)]	$1.1636	$1.0625	$1.0625
First Preference Shares, Series J [(3)]	-	-	$0.3514

[(1)] *First quarter 2010 dividends were declared in January 2010 resulting in five quarters of dividends declared in 2010*

[(2)] *A total of 10 million Five-Year Fixed Rate Reset First Preference Shares, Series H were issued on January 26, 2010 at $25.00 per share for net after-tax proceeds of $242 million, which are entitled to receive cumulative dividends in the amount of $1.0625 per share per annum for the first five years.*

[(3)] *A total of 8 million First Preference Shares, Series J were issued on November 13, 2012 at $25.00 per share for net after-tax proceeds of $196 million, which are entitled to receive cumulative dividends in the amount of $1.1875 per annum.*

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on Common and Preferred Shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

On December 11, 2012, the Board declared an increase in the quarterly Common Share dividend to $0.31 per share from $0.30 per share, with the first payment made on March 1, 2013, to holders of record as of February 14, 2013. Also on December 11, 2012 the Board declared a first quarter 2013 dividend on the First Preference Shares, Series C, E, F, G, H and J in accordance with the applicable annual prescribed rate and was paid on March 1, 2013 to holders of record as of February 14, 2013.

On March 20, 2013, the Board declared a second quarter 2013 dividend of $0.31 per Common Share and a second quarter 2013 dividend on the First Preference Shares, Series C, E, F, G, H and J in accordance with the applicable annual prescribed rate. In each case, the second quarter 2013 dividends will be paid on June 1, 2013 to holders of record as of May 17, 2013.

Common Shares

Dividends on Common Shares are declared at the discretion of the Board. Holders of Common Shares are entitled to dividends on a pro rata basis if, as, and when declared by the Board. Subject to the rights of the holders of the First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive dividends in priority to or rateably with the holders of the Common Shares, the Board may declare dividends on the Common Shares to the exclusion of any other class of shares of the Corporation.

On the liquidation, dissolution or winding-up of Fortis, holders of Common Shares are entitled to participate rateably in any distribution of assets of Fortis, subject to the rights of holders of First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or rateably with the holders of the Common Shares.

Holders of the Common Shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Fortis, other than separate meetings of holders of any other class or series of shares, and are entitled to one vote in respect of each Common Share held at such meetings.

First Preference Shares, Series C

Holders of the 5,000,000 First Preference Shares, Series C are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.3625 per share per annum. On or after June 1, 2011, the Corporation may, at its option, redeem for cash the First Preference Shares, Series C, in whole at any time, or in part from time to time, at $25.50 per share if redeemed before June 1, 2012; at $25.25 per share if redeemed on or after June 1, 2012 but before June 1, 2013; and at $25.00 per share if redeemed on or after June 1, 2013 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. On or after June 1, 2010, the Corporation may, at its option, convert all, or from time to time, any part of the outstanding First Preference Shares, Series C into fully paid and freely tradeable Common Shares of the Corporation. The number of Common Shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per Preference Share, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares. On or after September 1, 2013, each First Preference Share, Series C will be convertible at the option of the holder on the first day of September, December, March and June of each year into freely tradeable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares. If a holder of First Preference Shares, Series C elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference Shares, Series C for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series E

Holders of the 7,993,500 First Preference Shares, Series E are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. On or after June 1, 2013, the Corporation may, at its option, redeem all, or from time to time any part of, the outstanding First Preference Shares, Series E by the payment in cash of a sum per redeemed share equal to $25.75 if redeemed during the 12 months commencing June 1, 2013; $25.50 if redeemed during the 12 months commencing June 1, 2014; $25.25 if redeemed during the 12 months commencing June 1, 2015; and $25.00 if redeemed on or after June 1, 2016 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. On or after June 1, 2013, the Corporation may, at its option, convert all, or from time to time any part of the outstanding First Preference Shares, Series E into fully paid and freely tradeable Common Shares of the Corporation.

The number of Common Shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per First Preference Share, Series E, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares at such time. On or after September 1, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first business day of September, December, March and June of each year, into fully paid and freely tradeable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares. If a holder of First Preference Shares, Series E elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference, Shares E for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series F

Holders of the 5,000,000 First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. On or after December 1, 2011, the Corporation may, at its option, redeem for cash the First Preference Shares, Series F, in whole at any time or in part from time to time, at $26.00 per share if redeemed before December 1, 2012; at $25.75 per share if redeemed on or after December 1, 2012 but before December 1, 2013; at $25.50 per share if redeemed on or after December 1, 2013 but before December 1, 2014; at $25.25 per share if redeemed on or after December 1, 2014 but before December 1, 2015; and at $25.00 per share if redeemed on or after December 1, 2015 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series G

Holders of the 9,200,000 First Preference Shares, Series G are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.3125 per share per annum for each year up to and including August 31, 2013. For each five-year period after that date, the holders of First Preference Shares, Series G are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13%. On September 1, 2013, and on September 1 every five years thereafter, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series G, in whole at any time, or in part from time to time, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series H

Holders of the 10,000,000 First Preference Shares, Series H are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.0625 per share per annum for each year up to but excluding June 1, 2015. For each five-year period after that date, the holders of First Preference Shares, Series H are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 1.45%.

On each Series H Conversion Date, being June 1, 2015, and June 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series H, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series H Conversion Date, the holders of First Preference Shares, Series H, have the option to convert any or all of their First Preference Shares, Series H into an equal number of cumulative redeemable floating rate First Preference Shares, Series I.

Holders of the First Preference Shares, Series I will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada Treasury Bills plus 1.45%.

On each Series I Conversion Date, being June 1, 2020, and June 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On any date after June 1, 2015, that is not a Series I Conversion Date, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series I Conversion Date, the holders of First Preference Shares, Series I, have the option to convert any or all of their First Preference Shares, Series I into an equal number of First Preference Shares, Series H.

On any Series H Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series H outstanding, such remaining First Preference Shares, Series H will automatically be converted into an equal number of First Preference Shares, Series I. On any Series I Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series I outstanding, such remaining First Preference Shares, Series I will automatically be converted into an equal number of First Preference Shares, Series H. However, if such automatic conversions would result in less than 1,000,000 Series I First Preference Shares or less than 1,000,000 Series H First Preference Shares outstanding then no automatic conversion would take place.

First Preference Shares, Series J

Holders of the 8,000,000 First Preference Shares, Series J are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.1875 per share per annum. On or after December 1, 2017, the Corporation may, at its option, redeem for cash the First Preference Shares, Series J, in whole at any time or in part from time to time, at $26.00 per share if redeemed before December 1, 2018; at $25.75 per share if redeemed on or after December 1, 2018 but before December 1, 2019; at $25.50 per share if redeemed on or after December 1, 2019 but before December 1, 2020; at $25.25 per share if redeemed on or after December 1, 2020 but before December 1, 2021; and at $25.00 per share if redeemed on or after December 1, 2021 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

Debt Covenant Restrictions on Dividend Distributions

The Trust Indenture pertaining to the Corporation's $200 million Senior Unsecured Debentures contains a covenant which provides that Fortis shall not declare or pay any dividends (other than stock dividends or cumulative preferred dividends on preferred shares not issued as stock dividends) or make any other distribution on its shares or redeem any of its shares or prepay Subordinated Debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

The Corporation has a $1 billion unsecured committed revolving corporate credit facility, maturing in July 2015, that is available for interim financing of acquisitions and for general corporate purposes. The credit facility contains a covenant which provides that Fortis shall not declare or pay any dividends or make any other restricted payments if, immediately thereafter, consolidated debt to consolidated capitalization ratio would exceed 70% at any time.

As at December 31, 2012 and 2011, the Corporation was in compliance with its debt covenant restrictions pertaining to dividend distributions, as described above.

8.0 CREDIT RATINGS

Securities issued by Fortis and its utilities, that are currently rated, are rated by one or more credit rating agencies, namely, DBRS, S&P and/or Moody's. The ratings assigned to securities issued by Fortis and its utilities are reviewed by the agencies on an ongoing basis. Credit ratings and stability ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are not recommendations to buy, sell or hold securities. Ratings may be subject to revision or withdrawal at any time by the rating organization. The following table summarizes the Corporation's credit ratings as at March 22, 2013.

Fortis
Credit Ratings

Company	DBRS	S&P	Moody's
Fortis	A (low), stable (unsecured debt)	A-, stable (unsecured debt)	N/A
FHI	BBB (high), stable (unsecured debt)	N/A	Baa2, stable (unsecured debt)
FEI	A, stable (secured & unsecured debt)	N/A	A3, stable (unsecured debt)
FEVI	N/A	N/A	A3, stable (unsecured debt)
FortisAlberta	A (low), stable (senior unsecured debt)	A-, stable (senior unsecured debt)	Baa1, stable (senior unsecured debt)
FortisBC Electric	A (low), stable (secured & unsecured debt)	N/A	Baa1, stable (unsecured debt)
Newfoundland Power	A, stable (first mortgage bonds)	N/A	A2, stable (first mortgage bonds)
Maritime Electric	N/A	A, stable (senior secured debt)	N/A
Caribbean Utilities	A (low), stable (senior unsecured debt)	A-, stable (senior unsecured debt)	N/A

DBRS rates debt instruments by rating categories ranging from AAA to D, which represents the range from highest to lowest quality of such securities. DBRS states that: (i) 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; (ii) its 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; and (iii) every rating is based on quantitative and qualitative considerations that are relevant for the borrowing entity. According to DBRS, a rating of A by DBRS is in the middle of three subcategories within the third highest of nine major categories. Such rating is assigned to debt instruments considered to be of satisfactory credit quality and for which protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. Entities rated in the BBB category are considered to have long-term debt 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. The assignment of a (high) or (low) modifier within each rating category indicates relative standing within such category.

S&P long-term debt ratings are on a ratings scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities. S&P uses '+' or '-' designations to indicate the relative standing of securities within a particular rating category. S&P states that its credit ratings are

current opinions of the financial security characteristics with respect to the ability to pay under contracts in accordance with their terms. This opinion is not specific to any particular contract, nor does it address the suitability of a particular contract for a specific purpose or purchaser. An issuer rated A is regarded as having financial security characteristics to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than those in higher-rated categories.

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 states that its long-term debt ratings are opinions of relative risk of fixed-income obligations with an original maturity of one year or more and that 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 and such a debt rating is assigned to debt instruments considered to be of medium-grade quality. Debt instruments rated Baa are subject to moderate credit risk and may possess certain speculative characteristics. Debt instruments rated A are considered upper-medium grade and are subject to low credit risk.

9.0 MARKET FOR SECURITIES

The Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series J; and Subscription Receipts of Fortis are listed on the TSX under the symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F, FTS.PR.G, FTS.PR.H, FTS.PR.J and FTS.R, respectively.

The following table sets forth the reported high and low trading prices and trading volumes for the Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series J; and Subscription Receipts on a monthly basis for the year ended December 31, 2012.

Fortis 2012 Trading Prices and Volumes						
	Common Shares			**First Preference Shares, Series C**		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	33.67	32.66	7,561,933	26.61	25.90	21,229
February	34.31	31.76	19,233,895	26.54	25.50	50,239
March	33.17	31.70	11,072,696	25.90	25.53	35,364
April	34.35	31.88	7,960,525	26.25	25.53	275,288
May	34.98	32.08	11,877,137	25.95	25.38	135,930
June	34.00	32.03	12,638,137	25.80	25.42	62,747
July	33.54	32.37	5,854,206	26.10	25.52	61,688
August	34.03	32.38	7,323,690	25.99	25.52	20,856
September	33.54	32.45	8,714,537	25.70	25.53	24,897
October	33.93	33.01	7,237,611	26.75	25.59	15,786
November	34.20	32.41	7,284,164	26.26	25.60	35,134
December	34.35	32.83	9,203,571	25.80	25.35	19,055
	First Preference Shares, Series E			**First Preference Shares, Series F**		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	27.60	26.97	72,839	25.85	25.05	70,415
February	28.98	26.75	68,038	25.94	25.00	239,924
March	27.58	26.02	53,080	25.60	25.00	328,502
April	26.60	26.05	333,365	25.30	25.00	167,439
May	26.75	26.16	277,108	25.60	24.54	91,659
June	26.90	26.32	48,465	25.50	25.18	186,354
July	27.69	26.55	330,290	25.78	25.32	98,386
August	27.05	26.65	22,425	26.05	25.75	483,143
September	26.99	26.46	32,099	25.91	24.79	301,603
October	27.20	26.65	140,070	26.25	25.82	50,812
November	27.20	26.81	50,121	26.02	25.50	133,113
December	27.33	26.80	25,304	25.96	25.74	46,410
	First Preference Shares, Series G			**First Preference Shares, Series H**		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	26.45	25.75	47,858	26.00	25.50	263,320
February	26.50	25.35	88,246	26.72	25.60	111,592
March	25.92	25.46	168,124	25.99	25.45	85,935
April	25.85	25.60	54,552	25.93	25.46	28,764
May	25.95	25.52	71,254	26.00	24.95	70,501
June	25.75	25.42	125,720	25.88	24.84	123,562
July	25.80	25.31	118,123	25.84	25.32	535,584
August	25.62	25.14	207,283	25.80	25.30	222,408
September	25.40	25.20	127,973	25.85	25.25	122,267
October	25.40	25.15	183,254	25.74	25.10	1,145,687
November	25.45	24.62	276,986	25.75	25.30	363,052
December	24.74	24.05	382,796	25.75	25.40	132,976
	First Preference Shares, Series J (1)			**Subscription Receipts** (2)		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
June	-	-	-	32.20	31.18	972,550
July	-	-	-	32.49	31.33	1,806,901
August	-	-	-	32.85	31.70	1,035,164
September	-	-	-	32.77	31.68	549,750
October	-	-	-	33.44	32.34	705,085
November	25.40	25.04	2,091,868	33.70	32.30	591,342
December	25.80	25.23	247,752	34.50	32.64	824,408

(1) *The First Preference Shares, Series J were issued in November 2012.*
(2) *The Subscription Receipts were issued in June 2012.*

10.0 DIRECTORS AND OFFICERS

The Board adopted a director tenure policy in September 2010 and it is to be reviewed on a periodic basis. The tenure policy provides that Directors of the Corporation are to be elected for a term of one year and, except in appropriate circumstances determined by the Board, be eligible for re-election until the Annual Meeting of Shareholders next following the date on which they achieve age 70 or the 12th anniversary of their initial election to the Board. The policy does not apply to Mr. Marshall whose service on the Board is related to his tenure as CEO. The following chart sets out the name and municipality of residence of each of the Directors of Fortis and indicates their principal occupations within five preceding years.

Fortis Directors	
Name	**Principal Occupations Within Five Preceding Years**
PETER E. CASE *(1)* Kingston, Ontario	Mr. Case, 58, a Corporate Director, retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. During his 17-year career as senior investment analyst with CIBC World Markets and BMO Nesbitt Burns and its predecessors, Mr. Case's coverage of Canadian and select U.S. pipeline and energy utilities was consistently rated among the top rankings. He was then a consultant to the utility industry and its regulators for three years. Mr. Case was awarded a Bachelor of Arts and an MBA from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto. He was first elected to the Board in May 2005 and has been Chair of the Audit Committee of the Board since March 2011. Mr. Case was a Director of FortisOntario from 2003 through 2010 and served as Chair of the FortisOntario Board from 2009 through 2010. He does not serve as a director of any other reporting issuer.
FRANK J. CROTHERS *(2)* Nassau, Bahamas	Mr. Crothers, 68, is Chairman and Chief Executive Officer of Island Corporate Holdings Limited, Nassau, Bahamas, a private Bahamas-based investment company with diverse investments throughout the Caribbean, North America, Australia and South Africa. For more than 35 years, he has served on many public and private sector boards. For more than a decade he was on the Board of Harvard University Graduate School of Education and also served a three-year term as Chairman of CARILEC, the Caribbean Association of Electrical Utilities. Mr. Crothers is the past President of FortisTCI, which was acquired by the Corporation in August 2006. He serves as non-executive Vice Chair of the Board of Caribbean Utilities. Mr. Crothers was first elected to the Fortis Board in May 2007. He was previously a director of Belize Electricity from 2007 to 2010. Mr. Crothers is also a director of reporting issuers AML Limited, Talon Metals Corp. and Templeton Mutual Funds.
IDA J. GOODREAU *(3)* Vancouver, British Columbia	Ms. Goodreau, 61, is an Adjunct Professor at Sauder School of Business, University of British Columbia. She is the past President and Chief Executive Officer of LifeLabs. Prior to joining LifeLabs in March 2009, she was President and Chief Executive Officer of Vancouver Coastal Health Authority since 2002. Ms. Goodreau has held senior leadership roles in several Canadian and international pulp and paper and natural gas companies. She was awarded an MBA and a Bachelor of Commerce, Honors, degree from the University of Windsor and a Bachelor of Arts (English and Economics) from the University of Western Ontario. Ms. Goodreau was first elected to the Board in May 2009. She has served on numerous private and public sector boards and has been a director of FHI and FortisBC Inc. since 2007 and 2010, respectively. Ms. Goodreau does not serve as a director of any other reporting issuer.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
DOUGLAS J. HAUGHEY *(1)* Calgary, Alberta	Mr. Haughey, 56, is Chief Executive Officer of The Churchill Corporation, a construction and industrial services company focused on the western Canadian market. He served as President and Chief Executive Officer of Provident Energy Ltd., an owner/operator of natural gas liquids midstream services and marketing from 2010 through its successful sale to Pembina Pipeline in April 2012. Mr. Haughey served as President and Chief Executive Officer of WindShift Capital Corp., focused on energy infrastructure investment opportunities in North America, from 2008 through March 2010. From 1999 through 2008, he held several executive roles with Spectra Energy and predecessor companies. Mr. Haughey had overall responsibility for its western Canadian natural gas midstream business, was President and Chief Executive Officer of Spectra Energy Income Fund and also led Spectra's strategic development and mergers and acquisitions teams based in Houston, Texas. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with an MBA. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors. He was first elected to the Board in May 2009. Mr. Haughey became a director of FortisAlberta in 2010.
H. STANLEY MARSHALL Paradise, Newfoundland and Labrador	Mr. Marshall, 62, is President and Chief Executive Officer of the Corporation. He joined Newfoundland Power in 1979 and was appointed President and Chief Executive Officer of Fortis in 1996. Mr. Marshall graduated from the University of Waterloo with a Bachelor of Applied Science (Chemical Engineering) and from Dalhousie University with a Bachelor of Laws. He is a member of the Law Society of Newfoundland and Labrador and a Registered Professional Engineer in the Province of Newfoundland and Labrador. Mr. Marshall was first elected to the Board in October 1995. He serves on the boards of all Fortis utility subsidiaries in British Columbia, Ontario and the Caribbean and on the Board of Fortis Properties. Mr. Marshall is also a director of Enerflex Ltd.
JOHN S. McCALLUM *(1) (2)* Winnipeg, Manitoba	Mr. McCallum, 69, has been a Professor of Finance at the University of Manitoba since July 1973. He served as Chairman of Manitoba Hydro from 1991 to 2000 and as Policy Advisor to the Federal Minister of Finance from 1984 to 1991. Mr. McCallum graduated from the University of Montreal with a Bachelor of Arts (Economics) and a Bachelor of Science (Mathematics). He was awarded an MBA from Queen's University and a PhD in Finance from the University of Toronto. Mr. McCallum was first elected to the Board in July 2001 and was appointed Chair of the Governance and Nominating Committee of the Corporation in May 2005. He was previously a director of FortisBC Inc. and FortisAlberta from 2004 through 2010 and from 2005 through 2010, respectively. Mr. McCallum also serves as a director of IGM Financial Inc. and Toromont Industries Ltd.
HARRY McWATTERS *(2)* Summerland, British Columbia	Mr. McWatters, 67, is the founder and past President of Sumac Ridge Estate Wine Group, a leader in the British Columbia wine industry. He is President of Vintage Consulting Group Inc., Harry McWatters Inc., Okanagan Wine Academy and Black Sage Vineyards Ltd., all of which are engaged in various aspects of the British Columbia wine industry. Mr. McWatters was first elected to the Board in May 2007. He was elected to the Board of FortisBC Inc. in September 2005 and served as Chair of that Company's Board from 2006 through 2010. Mr. McWatters became a director of FHI in November 2007 and does not serve as a director of any other reporting issuer.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
RONALD D. MUNKLEY (2) (3) Mississauga, Ontario	Mr. Munkley, 66, a Corporate Director, retired in April 2009 as Vice Chairman and Head of the Power and Utility Business of CIBC World Markets. Mr. Munkley had acted as an advisor on most Canadian utility transactions since joining CIBC World Markets in 1998. Prior to that, he was employed at Enbridge Consumers Gas for 27 years, culminating as Chairman, President and Chief Executive Officer. Mr. Munkley led Enbridge Consumers Gas through deregulation and restructuring in the 1990s. He graduated from Queen's University with a Bachelor of Science, Honors (Engineering). Mr. Munkley is a professional engineer and has completed the Executive and Senior Executive Programs of the University of Western Ontario and the Partners, Directors and Senior Officers Certificate of the Canadian Securities Institute. He was first elected to the Board in May 2009. Mr. Munkley also serves as a director of Bird Construction Inc.
DAVID G. NORRIS (1) (2) (3) St. John's, Newfoundland and Labrador	Mr. Norris, 65, a Corporate Director, has been a financial and management consultant since 2001, prior to which he was Executive Vice President, Finance and Business Development, Fishery Products International Limited. Previously, he held Deputy Minister positions with the Department of Finance and Treasury Board, Government of Newfoundland and Labrador. Mr. Norris graduated with a Bachelor of Commerce, Honors, from Memorial University of Newfoundland and an MBA from McMaster University. He was first elected to the Board in May 2005 and was appointed Chair of the Board in December 2010. Mr. Norris served as Chair of the Audit Committee of the Board from May 2006 through March 2011. He was a director of Newfoundland Power from 2003 through 2010 and served as Chair of Newfoundland Power's Board from 2006 through 2010. Mr. Norris served as a director of Fortis Properties from 2006 through 2010. He does not serve as a director of any other reporting issuer.
MICHAEL A. PAVEY (1) (3) Moncton, New Brunswick	Mr. Pavey, 65, a Corporate Director, retired as Executive Vice President and Chief Financial Officer of Major Drilling Group International Inc. in September 2006. Prior to joining Major Drilling Group International Inc. in 1999, he held senior executive positions, including Senior Vice President and Chief Financial Officer, with TransAlta Corporation. Mr. Pavey graduated from the University of Waterloo with a Bachelor of Applied Science (Mechanical Engineering) and from McGill University with an MBA. He retired from the Board of Maritime Electric in February 2007 after a six-year term, which included service as Chair of that Company's Audit and Environment Committee from 2003 through 2007. Mr. Pavey was first elected to the Board in May 2004. He does not serve as a director of any other reporting issuer.
ROY P. RIDEOUT (2) (3) Halifax, Nova Scotia	Mr. Rideout, 65, a Corporate Director, retired as Chairman and Chief Executive Officer of Clarke Inc. in October 2002. Prior to 1998, he served as President of Newfoundland Capital Corporation Limited and held senior executive positions in the Canadian airline industry. Mr. Rideout graduated with a Bachelor of Commerce from Memorial University of Newfoundland and obtained designation as a Chartered Accountant. He was first elected to the Board in March 2001. Mr. Rideout is the Chair of the Human Resources Committee of the Board and has held that position since May 2003. He also serves as a director of NAV CANADA.

(1) *Serves on the Audit Committee*
(2) *Serves on the Governance and Nominating Committee*
(3) *Serves on the Human Resources Committee*

The following table sets out the name and municipality of residence of each of the officers of Fortis and indicates the office held.

Fortis Officers	
Name and Municipality of Residence	**Office Held**
H. Stanley Marshall Paradise, Newfoundland and Labrador	President and Chief Executive Officer (1)
Barry V. Perry Mount Pearl, Newfoundland and Labrador	Vice President, Finance and Chief Financial Officer (2)
Ronald W. McCabe St. John's, Newfoundland and Labrador	Vice President, General Counsel and Corporate Secretary (3)
Donna G. Hynes St. John's, Newfoundland and Labrador	Assistant Secretary (4)

(1) *Mr. Marshall was appointed President and Chief Operating Officer, effective October 1, 1995. Effective May 1, 1996, Mr. Marshall became Chief Executive Officer.*
(2) *Mr. Perry was appointed Vice President, Finance and Chief Financial Officer, effective January 1, 2004. Prior to that time, Mr. Perry was Vice President, Finance and Chief Financial Officer of Newfoundland Power.*
(3) *Mr. McCabe was appointed General Counsel and Corporate Secretary, effective January 1, 1997. Effective May 6, 2008, Mr. McCabe became Vice President, General Counsel and Corporate Secretary.*
(4) *Ms. Hynes was appointed Assistant Secretary, effective December 8, 1999. She joined Fortis as Manager, Investor and Public Relations in October 1999 and, prior to that time, was employed by Newfoundland Power.*

As at December 31, 2012, the directors and officers of Fortis, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 599,918 Common Shares, representing 0.3% of the issued and outstanding Common Shares of Fortis. The Common Shares are the only voting securities of the Corporation.

11.0 AUDIT COMMITTEE

11.1 Education and Experience

The education and experience of each Audit Committee Member that is relevant to such Member's responsibilities as a Member of the Audit Committee are set out below. As at December 31, 2012, the Audit Committee was composed of the following persons.

Fortis Audit Committee	
Name	**Relevant Education and Experience**
PETER E. CASE *(Chair)* Kingston, Ontario	Mr. Case retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. He was awarded a Bachelor of Arts and an MBA from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto.
DOUGLAS J. HAUGHEY Calgary, Alberta	Mr. Haughey is Chief Executive Officer of The Churchill Corporation. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with an MBA. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors.
JOHN S. McCALLUM Winnipeg, Manitoba	Mr. McCallum is a Professor of Finance at the University of Manitoba. He graduated from the University of Montreal with a Bachelor of Arts (Economics) and a Bachelor of Science (Mathematics). Mr. McCallum was awarded an MBA from Queen's University and a PhD in Finance from the University of Toronto.
DAVID G. NORRIS St. John's, Newfoundland and Labrador	Mr. Norris has been a financial and management consultant since 2001, prior to which he was Executive Vice President, Finance and Business Development, Fishery Products International Limited. He graduated with a Bachelor of Commerce, Honors, from Memorial University of Newfoundland and an MBA from McMaster University.
MICHAEL A. PAVEY Moncton, New Brunswick	Mr. Pavey retired as Executive Vice President and Chief Financial Officer of Major Drilling Group International Inc. in September 2006. Prior to joining Major Drilling Group International Inc. in 1999, he held senior executive positions, including Senior Vice President and Chief Financial Officer, with TransAlta Corporation. Mr. Pavey graduated from University of Waterloo with a Bachelor of Applied Science (Mechanical Engineering) and from McGill University with an MBA.

The Board has determined that each of the Audit Committee Members is independent and financially literate. Independent means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110 - *Audit Committees*. Financially literate means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be raised by the Corporation's consolidated financial statements.

11.2 Audit Committee Mandate

The text of the Corporation's Audit Committee Mandate is detailed below.

A. Objective

The Committee shall provide assistance to the Board by overseeing the external audit of the Corporation's annual financial statements and the accounting and financial reporting and disclosure processes and policies of the Corporation.

B. Definitions

In this mandate:

"AIF" means the Annual Information Form filed by the Corporation;

"Committee" means the Audit Committee appointed by the Board pursuant to this mandate;

"Board" means the board of directors of the Corporation;

"Corporation" means Fortis Inc.;

"Director" means a member of the Board;

"Financially Literate" means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be present in the Corporation's financial statements;

"External Auditor" means the firm of chartered accountants, registered with the Canadian Public Accountability Board or its successor, and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

"Independent" means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110;

"Internal Auditor" means the person employed or engaged by the Corporation to perform the internal audit function of the Corporation;

"Management" means the senior officers of the Corporation;

"MD&A" means the Corporation's management discussion and analysis prepared in accordance with National Instrument 51-102F1 in respect of the Corporation's annual and interim financial statements; and

"Member" means a Director appointed to the Committee.

C. Composition and Meetings

1. The Committee shall be appointed annually by the Board and shall be comprised of three (3) or more Directors, each of whom is Independent and Financially Literate and none of whom is a member of Management or an employee of the Corporation or of any affiliate of the Corporation.

2. The Board shall appoint a Chair of the Committee on the recommendation of the Corporation's Governance and Nominating Committee, or such other committee as the Board may authorize.

3. The Committee shall meet at least four (4) times each year and shall meet at such other times during the year as it deems appropriate. Meetings of the Committee shall be held at the call (i) of the Chair of the Committee, or (ii) of any two (2) Members, or (iii) of the External Auditor.

4. The President and Chief Executive Officer, the Vice President, Finance and Chief Financial Officer, the External Auditor and the Internal Auditor, shall receive notice of, and (unless otherwise determined by the Chair of the Committee) shall attend all meetings of the Committee.

5. A quorum at any meeting of the Committee shall be three (3) Members.

6. The Chair of the Committee shall act as chair of all meetings of the Committee at which the Chair is present. In the absence of the Chair from any meeting of the Committee, the Members present at the meeting shall appoint one of their Members to act as Chair of the meeting.

7. Unless otherwise determined by the Chair of the Committee, the Secretary of the Corporation shall act as secretary of all meetings of the Committee.

D. Oversight of the External Audit and the Accounting and Financial Reporting and Disclosure Processes and Policies

The primary purpose of the Committee is oversight of the Corporation's external audit and the accounting and financial reporting and disclosure processes and policies on behalf of the Board. Management of the Corporation is responsible for the selection, implementation and maintenance of appropriate accounting and financial reporting principles and policies and internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations. Management is responsible for the preparation and integrity of the financial statements of the Corporation.

1. Oversight of the External Audit

   The oversight of the external audit pertains to the audit of the Corporation's annual financial statements.

   1.1. The Committee is responsible for the evaluation and recommendation of the External Auditor to be proposed by the Board for appointment by the shareholders.

   1.2. In advance of each audit, the Committee shall review the External Auditor's audit plan including the general approach, scope and areas subject to risk of material misstatement.

   1.3. The Committee is responsible for approving the terms of engagement and fees of the External Auditor.

   1.4. The Committee shall review and discuss the Corporation's annual audited financial statements, together with the External Auditor's report thereon, and MD&A with Management and the External Auditor to gain reasonable assurance as to the accuracy, consistency and completeness thereof. The Committee shall meet privately with the External Auditor. The Committee shall oversee the work of the

External Auditor and resolve any disagreements between Management and the External Auditor.

1.5. The Committee shall use reasonable efforts, including discussion with the External Auditor, to satisfy itself as to the External Auditor's independence as defined in Canadian Auditing Standard – 260.

2. Oversight of the Accounting and Financial Reporting and Disclosure Processes

2.1. The Committee shall recommend the annual audited financial statements together with the MD&A for approval by the Board.

2.2. The Committee shall review the interim unaudited financial statements with the External Auditor and Management, together with the External Auditor's review engagement report thereon.

2.3. The Committee shall review and approve publication of the interim unaudited financial statements together with notes thereto, the interim MD&A and earnings media release on behalf of the Board.

2.4. The Committee shall review and recommend approval by the Board of the Corporation's AIF, Management Information Circular, any prospectus and other financial information or disclosure documents to be issued by the Corporation prior to their public release.

2.5. The Committee shall use reasonable efforts to satisfy itself as to the integrity of the Corporation's financial information systems, internal control over financial reporting and the competence of the Corporation's accounting personnel and senior financial management responsible for accounting and financial reporting.

2.6. The Committee shall use reasonable efforts to satisfy itself as to the appropriateness of the Corporation's material financing and tax structures.

2.7. The Committee shall be responsible for the oversight of the Internal Auditor.

2.8. The Committee shall monitor and report on the development of the Enterprise Risk Management Program.

3. Oversight of the Audit Committee Mandate and Policies

On a periodic basis, the Committee shall review and report to the Board on the Audit Committee Mandate as well as on the following policies:

3.1. Reporting Allegations of Suspected Improper Conduct and Wrongdoing Policy;

3.2. Derivative Financial Instruments and Hedging Policy;

3.3. Pre-Approval of Audit and Non-Audit Services Policy;

3.4. Hiring of Employees from Independent Auditing Firms Policy;

3.5. The Internal Audit Role and Function Policy; and

3.6. any other policies that may be established, from time to time, relating to accounting and financial reporting and disclosure processes; oversight of the external audit of the Corporation's financial statements; and oversight of the internal audit function.

E. Reporting

The Chair of the Committee, or another designated Member, shall report to the Board at each regular meeting on those matters which were dealt with by the Committee since the last regular meeting of the Board.

F. Other

1. The Committee shall perform such other functions as may, from time to time, be assigned to the Committee by the Board.

2. The Committee may approve, in circumstances that it considers appropriate, the engagement by the Committee or any Director of outside advisors or persons having special expertise at the expense of the Corporation.

11.3 Pre-Approval Policies and Procedures

The Audit Committee has established a policy which requires pre-approval of all audit and non-audit services provided to the Corporation and its subsidiaries by the Corporation's External Auditor. The Pre-Approval of Audit and Non-Audit Services Policy describes the services which may be contracted from the External Auditor and the limitations and authorization procedures related thereto. This policy defines services such as bookkeeping, valuations, internal audit and management functions which may not be contracted from the External Auditor and establishes an annual limit for permissible non-audit services not greater than the total fee for audit services. Audit Committee pre-approval is required for all audit and non-audit services.

11.4 External Auditor Service Fees

Fees incurred by the Corporation for work performed by Ernst & Young LLP, the Corporation's External Auditors, during each of the last two fiscal years for audit, audit-related and tax, and non-audit services were as follows.

Fortis External Auditor Service Fees ($ thousands)		
Ernst & Young LLP	**2012**	2011
Audit Fees	**2,484**	2,518
Audit-Related Fees	**806**	1,146
Tax Fees	**139**	153
Non-Audit Services	**138**	145
Total	**3,567**	3,962

Audit-related fees were higher in 2011 mainly due to work performed by Ernst & Young LLP in preparation for the Corporation's conversion to US GAAP, effective January 1, 2012, including audits and reviews performed on the Corporation's 2011 and 2010 comparative annual and quarterly consolidated financial statements, respectively, which were prepared in accordance with both Canadian GAAP and US GAAP.

12.0 TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares, Subscription Receipts and First Preference Shares of Fortis is Computershare Trust Company of Canada in Halifax, Montréal and Toronto.

Computershare Trust Company of Canada
9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.investorcentre.com/fortisinc

13.0 AUDITORS

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants, The Fortis Building, 7th Floor, 139 Water Street, St. John's, NL, A1C 1B2. The consolidated financial statements of the Corporation for the fiscal year ended December 31, 2012 have been audited by Ernst & Young LLP. Ernst & Young LLP report that they are independent of the Corporation in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Newfoundland.

14.0 ADDITIONAL INFORMATION

Reference is made to the MD&A and 2012 Audited Consolidated Financial Statements on pages 7 through 81 and pages 82 through 145, respectively, of the 2012 Fortis Inc. Annual Report to Shareholders, which pages are incorporated herein by reference. Additional information relating to the Corporation can be found on SEDAR at www.sedar.com.

Further additional information, including officers' and directors' remuneration and indebtedness, principal holders of the securities of Fortis, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in the Management Information Circular of Fortis dated March 21, 2013 for the May 9, 2013 Annual Meeting of Shareholders. Additional financial information is also provided in the 2012 Audited Consolidated Financial Statements and the MD&A.

Requests for additional copies of the above-mentioned documents, as well as the 2012 Annual Information Form, should be directed to the Corporate Secretary, Fortis, P.O. Box 8837, St. John's, NL, A1B 3T2 (telephone: 709.737.2800). In addition, such documentation and additional information relating to the Corporation is contained on the Corporation's website at www.fortisinc.com.

FORTIS INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2013

March 14, 2014

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2013

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DEFINITIONS OF CERTAIN TERMS

Certain terms used in this Annual Information Form are defined below:

"2013 Annual Information Form" means this Fortis Inc. Annual Information Form in respect of the year ended December 31, 2013;

"2013 Audited Consolidated Financial Statements" means the audited consolidated financial statements of Fortis Inc. as at and for the years ended December 31, 2013 and 2012 and related notes thereto;

"ACC" means Arizona Corporation Commission;

"Algoma Power" means Algoma Power Inc.;

"AUC" means Alberta Utilities Commission;

"BC Hydro" means BC Hydro and Power Authority;

"BCUC" means British Columbia Utilities Commission;

"BECOL" means Belize Electric Company Limited;

"Belize Electricity" means Belize Electricity Limited;

"BEPC" means Brilliant Expansion Power Corporation;

"Board" means Board of Directors of Fortis Inc.;

"BPC" means Brilliant Power Corporation;

"Canadian Niagara Power" means Canadian Niagara Power Inc.;

"Caribbean Utilities" means Caribbean Utilities Company, Ltd.;

"CAW" means Canadian Auto Workers-Retail/Wholesale;

"CEA" means Canadian Electricity Association;

"Central Hudson" means Central Hudson Gas & Electric Corporation;

"CEO" means Chief Executive Officer of Fortis Inc.;

"CEP" means Communications, Energy and Paperworkers Union;

"CH Energy Group" means CH Energy Group, Inc.;

"COPE" means Canadian Office and Professional Employees Union;

"Cornwall Electric" means Cornwall Street Railway, Light and Power Company, Limited;

"Corporation" means Fortis Inc.;

"CPA" means Canal Plant Agreement;

"CPC/CBT" means Columbia Power Corporation and Columbia Basin Trust;

"CUPE" means Canadian Union of Public Employees;

"DBRS" means DBRS Limited;

"DEC" means New York State Department of Environmental Conservation;

"EMS" means environmental management system;

"External Auditor" means the firm of Chartered Accountants registered with the Canadian Public Accountability Board or its successor and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

"FAES" means FortisBC Alternative Energy Services Inc.;

"FEI" means FortisBC Energy Inc.;

"FERC" means United States Federal Energy Regulatory Commission;

"FEVI" means FortisBC Energy (Vancouver Island) Inc.;

"FEWI" means FortisBC Energy (Whistler) Inc.;

"FHI" means FortisBC Holdings Inc., the parent company of FEI, FEVI and FEWI;

"Fortis" means Fortis Inc.;

"FortisAlberta" means FortisAlberta Inc.;

"FortisAlberta Holdings" means FortisAlberta Holdings Inc.;

"FortisBC Electric" means, collectively, the operations of FortisBC Inc. and its parent company, FortisBC Pacific Holdings Inc., but excludes its wholly owned partnership, Walden Power Partnership;

"FortisBC Energy companies" means, collectively, the operations of FEI, FEVI and FEWI;

"FortisBC Pacific Holdings" means FortisBC Pacific Holdings Inc.;

"FortisOntario" means, collectively, the operations of Canadian Niagara Power, Cornwall Electric and Algoma Power;

"Fortis Generation East Partnership" means Fortis Generation East LLP;

"Fortis Properties" means Fortis Properties Corporation;

"FortisTCI" means FortisTCI Limited;

"Fortis Turks and Caicos" means, collectively, FortisTCI and Turks and Caicos Utilities Limited;

"FortisUS Energy" means FortisUS Energy Corporation;

"FortisUS" means FortisUS Inc.;

"FortisUS Holdings" means FortisUS Holdings Nova Scotia Limited;

"FortisWest" means FortisWest Inc.;

"GHG" means greenhouse gas;

"GOB" means Government of Belize;

"Griffith" means Griffith Energy Services, Inc.;

"GSMIP" means Gas Supply Mitigation Incentive Plan;

"GWh" means gigawatt hour(s);

"Hydro One" means Hydro One Networks Inc.;

"IBEW" means International Brotherhood of Electrical Workers;

"IESO" means Independent Electricity System Operator of Ontario;

"ISO" means International Organization for Standardization;

"LNG" means liquefied natural gas;

"Management" means, collectively, senior officers of the Corporation;

"Maritime Electric" means Maritime Electric Company, Limited;

"MD&A" means the Corporation's Management Discussion and Analysis, located on pages 6 through 73 of the Corporation's 2013 Annual Report to Shareholders, prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations,* in respect of the Corporation's annual consolidated financial statements for the year ended December 31, 2013;

"MGP" means manufactured gas plant;

"Moody's" means Moody's Investors Service;

"MW" means megawatt(s);

"MWh" means megawatt hours;

"NB Power" means New Brunswick Power Corporation;

"NEB" means National Energy Board;

"Newfoundland Hydro" means Newfoundland and Labrador Hydro Corporation;

"Newfoundland Power" means Newfoundland Power Inc.;

"NYISO" means New York Independent System Operator;

"OEB" means Ontario Energy Board;

"Other Canadian Electric Utilities" means, collectively, the operations of FortisOntario and Maritime Electric;

"PCB" means polychlorinated biphenyl;

"PBR" means performance-based rate-setting;

"PEI" means Prince Edward Island;

"PEI Energy Accord" means Prince Edward Island Energy Accord;

"PJ" means petajoule(s);

"Point Lepreau" means NB Power Point Lepreau Nuclear Generating Station;

"PPA" means power purchase agreement;

"PRMP" means Price Risk Management Plan;

"PSC" means New York State Public Service Commission;

"PUB" means Newfoundland and Labrador Board of Commissioners of Public Utilities;

"ROE" means rate of return on common shareholders' equity;

"S&P" means Standard & Poor's;

"SEDAR" means the System for Electronic Document Analysis and Retrieval;

"Spectra Energy" means Westcoast Energy Inc. doing business as Spectra Energy Transmission;

"T&D" means transmission and distribution;

"TCU" means Turks and Caicos Utilities Limited;

"Teck Metals" means Teck Metals Ltd.;

"TJ" means terajoule(s);

"TransCanada" means TransCanada Pipelines Limited;

"TSX" means Toronto Stock Exchange;

"UFCW" means United Food and Commercial Workers;

"UNS Energy" means UNS Energy Corporation;

"US GAAP" means accounting principles generally accepted in the United States;

"USW" means United Steel Workers;

"UUWA" means United Utility Workers' Association of Canada;

"Walden" means Walden Power Partnership;

"Waneta Expansion" means the 335-MW hydroelectric generating facility being constructed adjacent to the existing Waneta Plant on the Pend d'Oreille River in British Columbia;

"Waneta Partnership" means the Waneta Expansion Limited Partnership between CPC/CBT and Fortis;

"WECA" means the Waneta Expansion Capacity Agreement; and

"Whistler" means the Resort Municipality of Whistler.

1.0 CORPORATE STRUCTURE

The 2013 Annual Information Form has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. Financial information has been prepared in accordance with US GAAP and is presented in Canadian dollars unless otherwise specified.

Except as otherwise stated, the information in the 2013 Annual Information Form is given as of December 31, 2013.

Fortis includes forward-looking information in the 2013 Annual Information Form within the meaning of applicable securities laws in Canada. The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. 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 2013 Annual Information Form, including the 2013 MD&A incorporated herein by reference, includes, but is not limited to, statements regarding: the principal business of Fortis remaining the ownership and operation of regulated electric and gas utilities; the Corporation's primary focus on Canada and the United States in the acquisition of regulated utilities; the pursuit of growth in the Corporation's non-regulated businesses in support of its regulated utility growth strategy; the expected capital investment in Canada's electricity sector over the 20-year period through 2030 to maintain system reliability; the expected timing of closing the acquisition of UNS Energy by Fortis and the expectation that the acquisition will be accretive to earnings per common share of Fortis in the first full year after closing, excluding one-time acquisition-related expenses; the expected increase in the Corporation's rate base at the time of closing the acquisition of UNS Energy; forecast 2014 midyear rate base for the Corporation's largest regulated utilities; the Corporations consolidated forecast gross capital expenditures for 2014 and in total over the five years 2014 through 2018; UNS Energy's forecast capital program for 2015 through 2018; the financing costs the Corporation expects to incur in 2014 associated with the convertible debentures represented by installment receipts; the expected net proceeds from the final installment of the convertible debentures; various natural gas investment opportunities that may be available to the Corporation; the nature, timing and amount of certain capital projects and their expected costs and time to complete; the expectation that the Corporation's significant capital expenditure program will support continuing growth in earnings and dividends; the assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed; the expectation that the Corporation's regulated utilities could experience disruptions and increased costs if they are unable to maintain their asset base; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long-term debt offerings; the expectation that the Corporation's subsidiaries will be able to source the cash required to fund their 2014 capital expenditure programs; the expected consolidated long-term debt maturities and repayments in 2014 and on average annually over the next five years; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to capital in the near to medium terms; the expectation that the combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2014; the expectation that any increase in interest expense and/or fees associated with renewed and extended credit facilities will not materially impact the Corporation's consolidated financial results for 2014; the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the estimated impact a decrease in revenue at Fortis Properties' Hospitality Division would have on annual basic earnings per common share; the expectation of no material adverse credit rating actions in the near term; the expected impact of a change in the US dollar-to-Canadian dollar foreign exchange rate on basic earnings per common share in 2014; the expectation that counterparties to derivative instruments will continue to meet their obligations; and the expectation that consolidated defined benefit net pension cost for 2014 will be comparable to that in 2013 and that there is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future.

The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received, and the expectation of regulatory stability; FortisAlberta's continued recovery of its cost of service and ability to earn its allowed ROE under performance-based rate-setting, which commenced for a five-year term effective January 1, 2013; the receipt of UNS Energy common shareholder approval and certain regulatory and government approvals required to close the acquisition of UNS Energy; the receipt of the final installment of the convertible debentures; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; no material capital project and financing cost overrun related to the construction of the Waneta Expansion; sufficient liquidity and capital resources; the expectation that the Corporation will receive appropriate compensation from the GOB for fair value of the Corporation's investment in Belize Electricity that was expropriated by the GOB; the expectation that BECOL will not be expropriated by the GOB; the continuation of regulator-approved mechanisms to flow through the cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices, electricity prices and fuel prices; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans and environmental laws that may materially negatively affect the operations and cash flows of the Corporation and its subsidiaries; no material change in public policies and directions by governments that could materially negatively affect the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under US GAAP beyond 2018 or the adoption of International Financial Reporting Standards after 2018 that allows for the recognition of regulatory assets and liabilities; the continued tax-deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology infrastructure; continued favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program.

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. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risk Management" in the MD&A for the year ended December 31, 2013 and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. Key risk factors for 2014 include, but are not limited to: uncertainty of the impact a continuation of a low interest rate environment may have on the allowed ROE at certain of the Corporation's regulated utilities in western Canada; uncertainty regarding the treatment of certain capital expenditures at FortisAlberta under the newly implemented PBR mechanism; risks relating to the ability to close the acquisition of UNS Energy Corporation, the timing of such closing and the realization of the anticipated benefits of the acquisition; risk associated with the amount of compensation to be paid to Fortis for its investment in Belize Electricity that was expropriated by the GOB; and the timeliness of the receipt of the compensation and the ability of the GOB to pay the compensation owing to Fortis.

All forward-looking information in the 2013 Annual Information Form is qualified in its entirety by the above cautionary statements 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.

1.1 Name and Incorporation

Fortis is a holding company that was incorporated as 81800 Canada Ltd. under the *Canada Business Corporations Act* on June 28, 1977 and continued under the *Corporations Act* (Newfoundland and Labrador) on August 28, 1987.

The articles of incorporation of the Corporation were amended to: (i) change its name to Fortis on October 13, 1987; (ii) set out the rights, privileges, restrictions and conditions attached to the Common Shares on October 15, 1987; (iii) designate 2,000,000 First Preference Shares, Series A on September 11, 1990; (iv) replace the class rights, privileges, restrictions and conditions attaching to the First Preference Shares and the Second Preference Shares on July 22, 1991; (v) designate 2,000,000 First Preference Shares, Series B on December 13, 1995; (vi) designate 5,000,000 First Preference Shares, Series C on May 27, 2003; (vii) designate 8,000,000 First Preference Shares, Series D and First Preference Shares, Series E on January 23, 2004; (viii) amend the redemption provisions attaching to the First Preference Shares, Series D on July 15, 2005; (ix) designate 5,000,000 First Preference Shares, Series F on September 22, 2006; (x) designate 9,200,000 First Preference Shares, Series G on May 20, 2008; (xi) designate 10,000,000 First Preference Shares, Series H and 10,000,000 First Preference Shares, Series I on January 20, 2010; (xii) designate 8,000,000 First Preference Shares, Series J on November 8, 2012; and (xiii) designate 12,000,000 First Preference Shares, Series K and 12,000,000 First Preference Shares, Series L on July 11, 2013.

Fortis redeemed all of its outstanding First Preference Shares, Series A and First Preference Shares, Series B on September 30, 1997 and December 2, 2002, respectively. On June 3, 2003, Fortis issued 5,000,000 First Preference Shares, Series C. On January 29, 2004, Fortis issued 8,000,000 First Preference Units, each unit consisting of one First Preference Share, Series D and one Warrant. During 2004 7,993,500 First Preference Units were converted into 7,993,500 First Preference Shares, Series E and 6,500 First Preference Shares, Series D remained outstanding. On September 20, 2005, the 6,500 First Preference Shares, Series D were redeemed by the Corporation. On September 28, 2006, Fortis issued 5,000,000 First Preference Shares, Series F. On May 23, 2008, Fortis issued 8,000,000 First Preference Shares, Series G and on June 4, 2008 issued an additional 1,200,000 First Preference Shares, Series G, following the exercise of an over-allotment option in connection with the offering of the 8,000,000 First Preference Shares, Series G. On January 26, 2010, Fortis issued 10,000,000 First Preference Shares, Series H. On November 13, 2012, Fortis issued 8,000,000 First Preference Shares, Series J. On July 10, 2013, the 5,000,000 First Preference Shares, Series C were redeemed by the Corporation. On July 18, 2013, Fortis issued 10,000,000 First Preference Shares, Series K.

The corporate head and registered office of Fortis is located at the Fortis Building, Suite 1201, 139 Water Street, P.O. Box 8837, St. John's, NL, Canada, A1B 3T2.

1.2 Inter-Corporate Relationships

Fortis is the largest investor-owned gas and electric distribution utility in Canada. The Corporation serves more than 2.4 million customers across Canada and in New York State and the Caribbean. Its regulated holdings account for 90% of total assets and include electric distribution utilities in five Canadian provinces, New York State and two Caribbean countries, and natural gas utilities in British Columbia, Canada and New York State. Fortis owns non-regulated hydroelectric generation assets in Canada, Belize and Upstate New York. The Corporation's non-utility investment is comprised of hotels and commercial real estate in Canada.

The following table lists the principal subsidiaries of the Corporation, their jurisdictions of incorporation and the percentage of votes attaching to voting securities held directly or indirectly by the Corporation as at March 13, 2014. This table excludes certain subsidiaries, the total assets of which individually constituted less than 10% of the Corporation's consolidated assets as at December 31, 2013, or the total revenue of which individually constituted less than 10% of the Corporation's 2013 consolidated revenue. Additionally, the principal subsidiaries together comprise approximately 81% of the Corporation's consolidated assets as at December 31, 2013 and approximately 77% of the Corporation's 2013 consolidated revenue.

Principal Subsidiaries		
Subsidiary	**Jurisdiction of Incorporation**	**Percentage of votes attaching to voting securities beneficially owned, controlled or directed by the Corporation**
FHI	British Columbia, Canada	100
Central Hudson [(1)]	New York State, United States	100
FortisAlberta [(2)]	Alberta, Canada	100
FortisBC Inc.[(3)]	British Columbia, Canada	100
Newfoundland Power	Newfoundland and Labrador, Canada	94 [(4)]

(1) *CH Energy Group, a New York State corporation, owns all of the shares of Central Hudson. FortisUS, a Delaware corporation, owns all of the shares of CH Energy Group. FortisUS Holdings, a Canadian corporation, owns all of the shares of FortisUS. Fortis owns all of the shares of FortisUS Holdings.*

(2) *FortisAlberta Holdings, an Alberta corporation, owns all of the shares of FortisAlberta. FortisWest, a Canadian corporation, owns all of the shares of FortisAlberta Holdings. Fortis owns all of the shares of FortisWest.*

(3) *FortisBC Pacific Holdings, a British Columbia corporation, owns all of the shares of FortisBC Inc. FortisWest, a Canadian corporation, owns all of the shares of FortisBC Pacific Holdings. Fortis owns all of the shares of FortisWest.*

(4) *Fortis owns all of the common shares; 16,513 First Preference Shares, Series A; 51,231 First Preference Shares, Series B; 15,100 First Preference Shares, Series D; and 182,300 First Preference Shares, Series G of Newfoundland Power which, as at March 13, 2014, represented 94% of its voting securities. The remaining 6% of Newfoundland Power's voting securities consist of First Preference Shares, Series A, B, D and G, which are primarily held by the public.*

2.0 GENERAL DEVELOPMENT OF THE BUSINESS

2.1 Three-Year History

Over the past three years, Fortis has experienced growth in its business operations. Total assets have grown 34% from approximately $13.4 billion as at December 31, 2010 to approximately $17.9 billion as at December 31, 2013. The Corporation's shareholders' equity has also grown 49% from approximately $4.3 billion as at December 31, 2010 to approximately $6.4 billion as at December 31, 2013. Net earnings attributable to common equity shareholders have increased from $320 million in 2010 to $353 million in 2013.

The growth in business operations reflects the Corporation's profitable growth strategy for its principal businesses of regulated gas and electricity distribution. This strategy includes a combination of organic growth through the Corporation's consolidated capital expenditure program and growth through acquisitions.

The Corporation's gross consolidated capital expenditures for 2013 were approximately $1.2 billion, which marks the fifth consecutive year that capital investment has surpassed $1 billion. Organic asset growth at the regulated utilities has been driven by the capital expenditure programs in western Canada. Total assets at FortisAlberta and the FortisBC gas and electric utilities have grown by approximately 38% and 14%, respectively, over the past three years. Organic growth at non-regulated operations has been driven by approximately $579 million in total that has been spent on the Waneta Expansion since construction began in late 2010.

Over the past three years, Fortis has also increased its regulated utility investments through acquisitions. In June 2013 Fortis acquired all the outstanding shares of CH Energy Group for US$1.5 billion, including the assumption of US$518 million of debt on closing. CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson, is a regulated T&D utility serving approximately 300,000 electric customers and 77,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. In March 2013, FortisBC Electric acquired the electrical utility assets of the City of Kelowna for approximately $55 million, which allows FortisBC Electric to directly serve some 15,000 customers formerly served by the City. FortisBC Electric had provided the City with electricity under a wholesale tariff and had operated and maintained the City's electrical utility assets under contract since 2000. In 2012, Fortis acquired the electricity distribution assets of Port Colborne for $7 million and acquired TCU for $8 million, net of debt assumed. The Corporation also increased its non-regulated investments over the last three years, through the acquisition of two hotels in Canada.

The GOB expropriated the Corporation's investment in Belize Electricity in June 2011. As a result of no longer controlling the operations of the utility, the Corporation discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011. As at December 31, 2013, the book value of the expropriated investment, including foreign exchange impacts, was $108 million. For further information on the expropriation of Belize Electricity, refer to the "Business Risk Management - Expropriation of Shares in Belize Electricity" section of the Corporation's MD&A.

2.2 Pending Acquisition

In December 2013 Fortis entered into an agreement and plan of merger to acquire UNS Energy (NYSE:UNS) for US$60.25 per common share in cash, representing an aggregate purchase price of approximately US$4.3 billion, including the assumption of approximately US$1.8 billion of debt on closing. UNS Energy is a vertically integrated utility services holding company, headquartered in Tucson, Arizona, engaged through three subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona, serving approximately 656,000 electricity and gas customers.

The closing of the acquisition, which is expected to occur by the end of 2014, is subject to receipt of UNS Energy common shareholder approval and certain regulatory and government approvals, including approval by the ACC and FERC, and compliance with other applicable U.S. legislative requirements and the satisfaction of customary closing conditions. In January 2014 Fortis and UNS Energy filed a joint application with the ACC seeking approval of the acquisition. The FERC application was filed in February 2014. UNS Energy mailed proxy materials to its shareholders and expects the shareholder vote on the transaction to occur on March 26, 2014.

For the purpose of financing the acquisition, in December 2013 the Corporation obtained a commitment letter from a syndicate of banks led by The Bank of Nova Scotia to provide an aggregate of $2 billion non-revolving term credit facilities, consisting of a $1.7 billion short-term bridge facility, repayable in full nine months following its advance, and a $300 million medium-term bridge facility, repayable in full on the second anniversary of its advance.

To finance a portion of the pending acquisition of UNS Energy, in January 2014 Fortis, through a direct wholly owned subsidiary, completed the sale of $1.8 billion aggregate principal amount of 4% convertible unsecured subordinated debentures, represented by Installment Receipts.

The debentures were sold on an installment basis at a price of $1,000 per debenture, of which $333 was paid on closing and the remaining $667 is payable on a date to be fixed following satisfaction of all conditions precedent to the closing of the acquisition of UNS Energy. Prior to the final installment date, the debentures are represented by Installment Receipts. The Installment Receipts began trading on the TSX on January 9, 2014 under the symbol "FTS.IR". The debentures will not be listed. The debentures will mature on January 9, 2024 and bear interest at an annual rate of 4% per $1,000 principal amount of debentures until and including the final installment date, after which the interest rate will be 0%.

At the option of the investors and provided that payment of the final installment has been made, each debenture will be convertible into Common Shares of Fortis at any time after the final installment date but prior to maturity or redemption by the Corporation at a conversion price of $30.72 per common share, being a conversion rate of 32.5521 Common Shares per $1,000 principal amount of debentures.

For additional information with respect to the debentures, refer to the "Significant Items – Convertible Debentures Represented by Installment Receipts" section of the Corporation's MD&A.

2.3 Outlook

Fortis is focused on closing the UNS Energy acquisition by the end of 2014. The acquisition is consistent with the Corporation's strategy of investing in high-quality regulated utility assets in Canada and the United States and is expected to be accretive to earnings per common share of Fortis in the first full year after closing, excluding one-time acquisition-related costs. The acquisition lessens the business risk for Fortis by enhancing the geographic diversification of the Corporation's regulated assets, resulting in no more than one-third of total assets being located in any one regulatory jurisdiction.

At the time of closing the acquisition of UNS Energy, the Corporation's consolidated rate base is expected to increase by approximately US$3 billion, and Fortis utilities will serve more than 3,000,000 electricity and gas customers.

Following closing of the acquisition of UNS Energy, regulated utilities in the United States will represent approximately one-third of total assets, and regulated utilities and hydroelectric generation assets will comprise approximately 97% of the Corporation's total assets.

The Corporation expects earnings per common share growth in 2015 and beyond as a result of contributions from the Central Hudson and UNS Energy acquisitions, and the completion of the Waneta Expansion in 2015 and the Tilbury LNG facility expansion in 2016, which will support continuing growth in dividends.

Over the five-year period 2014 through 2018, the Corporation's capital program is expected to exceed $6.5 billion, and will support continuing growth in earnings and dividends. Additionally, UNS Energy has forecast that its capital program for 2015 through 2018 will be approximately $1.5 billion (US$1.4 billion).

The approximate breakdown of the capital spending expected to be incurred over the five-year period 2014 through 2018, excluding UNS Energy, is as follows: 50% at Canadian Regulated Electric Utilities, driven by FortisAlberta; 27% at Canadian Regulated Gas Utilities; 11% at Central Hudson; 5% at Caribbean Regulated Electric Utilities and the remaining 7% at non-regulated operations. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, the approximate breakdown of the total capital spending to be incurred is as follows: 37% to meet customer growth; 46% to ensure continued and enhanced performance, reliability and safety of generation and T&D assets, i.e., sustaining capital expenditures; and 17% for facilities, equipment, vehicles, information technology and other assets.

Gross consolidated capital expenditures for 2014 are expected to be approximately $1.4 billion, as summarized in the following table. Planned capital expenditures are based on detailed forecasts of energy demand, weather, cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from forecasts.

Forecast Gross Consolidated Capital Expenditures [(1)] **Year Ending December 31, 2014**	
	($ millions)
FortisBC Energy Companies	329
Central Hudson	122
FortisAlberta	413
FortisBC Electric	130
Newfoundland Power	105
Other Canadian Electric Utilities	56
Regulated Electric Utilities - Caribbean	61
Non-Regulated - Fortis Generation	131
Non-Regulated - Non-Utility [(2)]	83
Total	**1,430**

(1) *Relates to forecast cash payments to acquire or construct utility capital assets, non-utility capital assets and intangible assets, as would be reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of allowance for funds used during construction.*

(2) *Includes forecast capital expenditures of approximately $13 million at FAES, which is reported in the Corporate and Other segment*

The most significant capital projects for 2014 include the continuation of the Waneta Expansion, with approximately $126 million expected to be spent in 2014, and the expansion of the Tilbury LNG facility at FEI. In November 2013 the Government of British Columbia announced the exemption of the Tilbury LNG Facility expansion from a Certificate of Public Convenience and Necessity review by the BCUC. The expansion is expected to include a second LNG tank and a new liquefier, both to be in service in 2016. The expansion will increase LNG production and storage capabilities. The Tilbury LNG Facility expansion is subject to additional regulatory and environmental permits and approvals. The Government of British Columbia imposed an upper limit of $400 million for project costs associated with the expansion, with approximately $100 million expected to be spent in 2014.

The Corporation's subsidiaries expect to have reasonable access to long-term capital in 2014 to fund their capital expenditure programs.

Forecast 2014 midyear rate base for the Corporation's largest regulated utilities is provided in the following table.

Forecast 2014 Midyear Rate Base	
	($ billions)
FortisBC Energy Companies	3.7
Central Hudson	1.1
FortisAlberta	2.5
FortisBC Electric	1.2
Newfoundland Power	1.0

3.0 DESCRIPTION OF THE BUSINESS

Fortis is principally an international gas and electric distribution utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation and non-utility assets, which are treated as two separate segments. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

The business segments of the Corporation are: (i) Regulated Gas Utilities - Canadian; (ii) Regulated Gas & Electric Utility - United States; (iii) Regulated Electric Utilities - Canadian; (iv) Regulated Electric Utilities - Caribbean; (v) Non-Regulated - Fortis Generation; (vi) Non-Regulated – Non-Utility; and (vii) Corporate and Other.

The following sections describe the operations included in each of the Corporation's reportable segments.

3.1 Regulated Gas Utilities - Canadian

3.1.1 *FortisBC Energy Companies*

The Regulated Gas Utilities - Canadian segment comprises the natural gas T&D business of the FortisBC Energy companies, which primarily includes FEI, FEVI and FEWI.

FEI is the largest distributor of natural gas in British Columbia, serving approximately 850,000 customers in more than 100 communities. Major areas served by FEI are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of British Columbia.

FEVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island, and serves approximately 103,000 customers on Vancouver Island and along the Sunshine Coast of British Columbia.

FEWI owns and operates the natural gas distribution system in Whistler, British Columbia, which provides service to approximately 3,000 customers.

In addition to providing T&D services to customers, the FortisBC Energy companies also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

The FortisBC Energy companies own and operate approximately 46,000 kilometres of natural gas pipelines and met a peak day demand of 1,341 TJ in 2013.

Market and Sales

Annual natural gas sales volumes at the FortisBC Energy companies increased to 200 PJ in 2013 from 199 PJ in 2012. Revenue decreased to $1,378 million in 2013 from $1,426 million in 2012. The decrease in revenue was primarily due to an overall lower cost of natural gas charged to customers and decreases in the allowed ROE and equity component of capital structure. The decrease was partially offset by an increase in the delivery component of customer rates effective January 1, 2013.

The following table compares the composition of 2013 and 2012 revenue and natural gas volumes of the FortisBC Energy companies by customer class.

FortisBC Energy Companies Revenue and Gas Volumes by Customer Class				
	Revenue (%)		**PJ Volumes (%)**	
	2013	2012	**2013**	2012
Residential	**56.1**	55.7	**37.5**	36.7
Commercial	**29.6**	30.1	**23.5**	23.6
Industrial	**3.0**	3.9	**2.5**	3.0
	88.7	89.7	**63.5**	63.3
Transportation	**6.5**	6.0	**30.5**	31.2
Other (1)	**4.8**	4.3	**6.0**	5.5
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes amounts under fixed-revenue contracts and revenue from sources other than from the sale of natural gas*

Gas Purchase Agreements

In order to ensure supply of adequate resources to provide reliable natural gas deliveries to its customers, the FortisBC Energy companies purchase supplies from a limited list of producers, aggregators and marketers, while adhering to standards of counterparty creditworthiness and contract execution and/or management policies. FEI contracts for approximately 119 PJ of baseload and seasonal supply to meet the requirements of both FEI and FEWI, of which 104 PJ is sourced in northeastern British Columbia and transported to FEI's system on Spectra Energy's westcoast pipeline T-South system, and 15 PJ is comprised of Alberta-sourced supply, transported into British Columbia via TransCanada's Alberta and British Columbia systems, and then through FEI's Southern Crossing pipeline. FEVI contracts for about 11 PJ of annual supply comprised of baseload and seasonal contracts, primarily sourced in British Columbia. The majority of supply contracts in the current portfolio are seasonal for either the summer period (April to October) or winter period (November to March), with a few contracts that range from one to ten years in length.

Through the operation of regulatory deferrals, any difference between the forecast cost of natural gas purchases, as reflected in residential and commercial customer rates, and the actual cost of natural gas purchases is recovered from, or refunded to, customers in future rates.

Core market customers rely upon the FortisBC Energy companies to procure and deliver gas supply on their behalf, while transportation-only industrial customers are responsible for procuring and delivering their own gas supply directly to the FortisBC Energy companies' system, which is then delivered to their operating premises by the FortisBC Energy companies. FEI and FEVI contract for transportation capacity on third-party pipelines, such as those owned by Spectra Energy and TransCanada, which are regulated by the NEB, to transport gas supply from various market hubs and locations to FEI's system, which is then transported to the FEVI and FEWI systems. The FortisBC Energy companies pay both fixed and variable charges for the use of transportation capacity on these pipelines, which are recovered through rates paid by core market customers. The FortisBC Energy companies contract for firm transportation capacity in order to ensure they are able to meet their obligations to supply customers within their broad operating region under all reasonable demand scenarios.

Gas Storage and Peak-Shaving Arrangements

The FortisBC Energy companies incorporate peak shaving and gas storage facilities into their portfolio to:

(i) supplement contracted baseload and seasonal gas supply in the winter months while injecting excess baseload supply to refill storage in the summer months;
(ii) mitigate the risk of supply shortages during cooler weather and a peak day;
(iii) more effectively manage the cost of gas during winter months; and
(iv) balance daily supply and demand on the distribution system, mainly over the course of the winter months.

FEI holds approximately 31.4 PJ of total storage capacity, consisting of on-system peak-shaving LNG facilities owned by FEI and FEVI, and off-system capacity contracted with third parties. The Tilbury LNG storage facility provides FEI with 0.61 PJ of total storage capacity and 0.16 PJ per day of deliverability for storage withdrawals. FEI contracts with FEVI for an additional 1.42 PJ of storage capacity and 0.14 PJ per day withdrawal capability from FEVI's Mt. Hayes LNG facility. FEI also contracts for off-system storage capacity from external parties at various locations throughout British Columbia, Alberta and the Pacific Northwest region of the United States. These storage facilities and supply from peak-shaving contracts can deliver a maximum daily rate of 0.7 PJ on a combined basis during the coldest months of December through February. The resources held by FEI are also used to serve FEWI.

FEVI holds a total of 3 PJ of storage capacity, including on-system capacity provided by the Mount Hayes LNG storage facility and off-system capacity contracted with third parties. The Mount Hayes LNG storage facility provides FEVI with both peaking gas supply and system capacity during extreme cold events and emergencies.

Off-System Sales

The FortisBC Energy companies engage in off-system sales activities which allow for the recovery of, or mitigation of, costs on any unutilized supply and/or pipeline and storage capacity that is available once customers' daily load requirements are met. Under the GSMIP revenue-sharing model, which is approved by the BCUC, the FortisBC Energy companies can earn an incentive payment for its mitigation activities based on the total savings generated for customers. Historically, FEI has earned approximately $1 million annually through the GSMIP while the remaining savings are credited back to customers through reduced rates. In the gas contract year ended October 31, 2013, total net revenue was approximately $49 million as a result of FEI's mitigation activities, on which FEI would earn an incentive payment of approximately $1 million pending approval by the BCUC.

The current GSMIP program, approved by the BCUC following a review of the program in 2011, defines the revenue sharing between customers and the shareholder. The program has been in effect since November 1, 2011 and the BCUC recently approved a three-year extension of the program for the period November 1, 2013 to October 31, 2016 and, effective November 1, 2013, extended the program to include mitigation activities performed by FEI on behalf of FEVI.

Price Risk Management Plan

In the past, FEI and FEVI have engaged in price risk management activities to minimize the exposure to fluctuations in the market price of natural gas. These have typically included the use of derivative instruments which were pursuant to a BCUC-approved PRMP. The primary objectives of the price risk management strategy incorporated in the PRMP were to reduce price volatility and ensure, to the extent possible, that natural gas commodity costs remain competitive against electricity rates. In July 2010 the BCUC ordered a review of FEI's and FEVI's PRMP hedging strategy in the context of the *Clean Energy Act* (British Columbia) and the expectation of increased domestic natural gas supply. In July 2011 following a comprehensive review process, the BCUC concluded that the hedging strategy was no longer in the best interests of customers and directed FEI to suspend the majority of its gas commodity hedging activities. FEI was further directed to manage hedges already in place through to expiry.

The existing hedging contracts will continue in effect through to their maturity and the FortisBC Energy companies' ability to fully recover the commodity cost of gas in customer rates remains unchanged. FEI currently has hedges in place through to the end of March 2014 from previously approved PRMPs. Similarly, FEVI has hedges in place through to October 2014.

Unbundling

The FEI Customer Choice Program allows eligible FEI commercial and residential customers to choose to buy their natural gas supply from FEI or directly from third-party marketers. FEI continues to provide the delivery service of the natural gas to all its customers.

The Customer Choice Program has been in place since November 2004 for commercial customers and November 2007 for residential customers. As at December 31, 2013, of the approximate 78,000 eligible commercial customers, approximately 7,600 were participating in the program by purchasing their commodity supply from alternate providers. Similarly, of the approximate

765,000 eligible residential customers approximately 38,000 were participating in the program as at December 31, 2013.

Legal Proceedings

In April 2013 FHI and Fortis were named as defendants in an action in the British Columbia Supreme Court by the Coldwater Indian Band. The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Coldwater Indian Band seeks orders cancelling the right of way and claims damages for wrongful interference with the Coldwater Indian Band's use and enjoyment of reserve lands. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the 2013 Audited Consolidated Financial Statements.

FEI was the plaintiff in a British Columbia Supreme Court action against the City of Surrey in which FEI sought the court's determination on the manner in which costs related to the relocation of a natural gas transmission pipeline would be shared between the Company and the City of Surrey. The relocation was required due to the development and expansion of the City of Surrey's transportation infrastructure. FEI claimed that the parties had an agreement that dealt with the allocation of costs. The City of Surrey advanced counterclaims, including an allegation that FEI breached the agreement and that the City of Surrey suffered damages as a result. In December 2013, the court issued a decision ordering FEI and the City of Surrey to share equally the cost of the pipeline relocation. The court also decided that the City of Surrey was successful in its counterclaim that FEI breached the agreement. The amount of damages that may be awarded to the City of Surrey at a subsequent hearing cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the 2013 Audited Consolidated Financial Statements.

Human Resources

As at December 31, 2013, the FortisBC Energy companies employed 1,720 full-time equivalent employees. Approximately 71% of the employees are represented by IBEW and COPE under collective agreements.

IBEW represents employees in specified occupations in the areas of T&D. An IBEW collective agreement came into effect in mid-2012 and expires on March 31, 2015.

There are two collective agreements between FEI and COPE. The first collective agreement, representing employees in specified occupations in the areas of administration and operations support, expires on March 31, 2015. The second COPE collective agreement, representing customer service employees, expires on March 31, 2014; however, FEI has negotiated an agreement with COPE, subject to ratification, that expires on March 31, 2017.

3.2 Regulated Gas & Electric Utility - United States

3.2.1 *Central Hudson*

Central Hudson is a regulated T&D utility serving approximately 300,000 electricity customers and 77,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. Central Hudson was acquired by Fortis as part of the acquisition of CH Energy Group in June 2013.

Central Hudson serves a territory comprising approximately 6,700 square kilometres in the Hudson Valley. Electric service is available throughout the territory, and natural gas service is provided in and about the cities of Poughkeepsie, Beacon, Newburgh, and Kingston, New York, and in certain outlying and intervening territories.

Central Hudson's electric T&D system consists of approximately 15,000 kilometres of line and met a peak demand of 1,202 MW in 2013. The Company's natural gas system consists of approximately 2,200 kilometres of T&D pipelines and met a peak demand of 125 TJ in 2013.

Market and Sales

Electricity sales year to date from acquisition were 2,629 GWh, compared to 2,665 GWh for the same period last year. Gas volumes year to date from acquisition were 9 PJ compared to 12 PJ for the same period last year. Revenue year to date from acquisition was US$321 million compared to US$318 million for the same period last year.

The following table provides the composition of Central Hudson's 2013 revenue, electricity sales, and gas volumes by customer class.

Central Hudson [(1)] 2013 Revenue and Electricity & Gas Sales by Customer Class			
	Revenue (%)	**GWh Sales (%)**	**PJ Volumes (%)**
Residential	61.5	40.5	40.2
Commercial	29.5	38.1	37.8
Industrial	4.6	20.4	20.4
Other [(2)]	4.4	1.0	1.6
Total	100.0	100.0	100.0

(1) *The information presented is for the year ended December 31, 2013. Central Hudson was acquired by Fortis in June 2013; therefore, only financial results from the date of acquisition June 27, 2013 are reflected in the Corporation's 2013 Audited Consolidated Financial Statements.*

(2) *Includes electricity sales and gas volumes to other entities for resale and revenue from sources other than from the sale of electricity and gas*

Power Supply

Central Hudson is obligated to supply electricity to its retail electric customers. Central Hudson owns minimal generating capacity and relies on purchased capacity and energy from third-party providers to meet the demands of its full-service customers. Central Hudson's retail customers may elect to procure electricity from third-party suppliers or may continue to rely on the Company. As part of its requirement to supply customers who continue to rely on Central Hudson for their energy supply, Central Hudson is party to a revenue sharing agreement which provides that, for a 10-year period starting in 2011, Central Hudson may share in a portion of Nine Mile Point LLC's power sales revenues for electricity generated at Unit No. 2 of the Nine Mile Point Nuclear Generating Station, depending on the actual price of electricity. In 2013 actual pricing of electricity exceeded contractual pricing; therefore, there was no revenue collected by Central Hudson under the agreement. There are no circumstances under the agreement in which Central Hudson would be required to make payments.

Central Hudson entered into agreements with Entergy Nuclear Power Marketing, LLC to purchase electricity, and not capacity, on a unit-contingent basis at defined prices from January 1, 2011 through December 31, 2013. For the year ended December 31, 2013, energy supplied under these agreements cost approximately US$20 million, which represents approximately 14% of Central Hudson's full-service customer requirements.

These contracts meet the definition of a normal purchase and are, therefore, excluded from current accounting requirements related to derivatives. In the event the above-noted counterparty is unable to fulfill its commitment to deliver under the terms of the agreements, Central Hudson would obtain the supply from the NYISO market, and under the Company's current rate-making treatment, recover the full cost from customers.

Central Hudson must also acquire sufficient peak load capacity to meet the peak load requirements of its full-service customers. This capacity requirement is met through contracts with capacity providers, purchases from the NYISO capacity market, and the Company's own generating capacity. In 2013 Central Hudson's generating capacity provided less than 2% of its energy needs and the remaining 98% was from purchased power.

In November 2013 Central Hudson entered into a contract to purchase 200 MW of installed capacity from May 1, 2014 through April 30, 2017. The NYISO has been authorized by FERC to create a new capacity zone in the Lower Hudson Valley to maintain system reliability and attract investments in new and existing generation, which is expected to be implemented in May 2014. The key terms of the contract provide that Central Hudson will pay the settlement price in the NYISO Capacity Spot Market auction for the relevant month of delivery minus US$0.175 per kilowatt-month, times the contract quantity of the product delivered during the month.

Gas Purchases

In order to assure an adequate, reliable source of gas supply, Central Hudson purchases its requirements from an approved list of marketers and producers. During the winter season, Central Hudson contracts for approximately 7.61 PJ of supply to meet the requirements of its customers. Approximately 2.17 PJ of gas is sourced from Canada and is transported on the TransCanada pipeline system and Iroquois Pipeline. The remaining requirements are acquired from domestic sources and are transported on the Tennessee Gas Pipeline, Algonquin Pipeline, Millennium and Columbia Gas Pipeline systems. Central Hudson also contracts for market area storage with the Tennessee Gas Pipeline, Columbia Pipeline and Dominion Transmission. Spot gas is purchased on an as-needed basis. The majority of supply contracts in the current portfolio are seasonal for either the summer period (April to October) or the winter period (November to March) with a few contracts one year or longer in length.

Legal Proceedings

In May 2012 CH Energy Group and Fortis entered into a proposed settlement agreement with counsel to plaintiff shareholders pertaining to several complaints, which named Fortis and other defendants, which were filed in, or transferred to, the Supreme Court of the State of New York, County of New York, relating to the acquisition of CH Energy Group by Fortis. The complaints generally alleged that the directors of CH Energy Group breached their fiduciary duties in connection with the acquisition and that CH Energy Group, Fortis, FortisUS and Cascade Acquisition Sub Inc. aided and abetted that breach. The settlement agreement is subject to court approval. In February 2014 the Supreme Court of the State of New York, County of New York, issued a Consent Order preliminarily certifying the matter as a class action and providing directions leading to a Settlement Hearing to be held in June 2014.

Prior to the acquisition of CH Energy Group, various asbestos lawsuits had been brought against Central Hudson. While a total of 3,342 asbestos cases have been raised, 1,170 remained pending as at December 31, 2013. Of the cases no longer pending against Central Hudson, 2,017 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 155 cases. The Company is presently unable to assess the validity of the remaining asbestos lawsuits; however, based on information known to Central Hudson at this time, including the Company's experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in the 2013 Audited Consolidated Financial Statements.

Environmental Contingencies

Former MGP Facilities
Central Hudson and its predecessors owned and operated MGPs to serve their customers' heating and lighting needs. These plants manufactured gas from coal and oil beginning in the mid- to late 1800s with all sites ceasing operations by the 1950s. This process produced certain by-products that may pose risks to human health and the environment.

The DEC, which regulates the timing and extent of remediation of MGP sites in New York State, has notified Central Hudson that it believes the Company or its predecessors at one time owned and/or operated MGPs at seven sites in Central Hudson's franchise territory. The DEC has further requested that the Company investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Clean-up Agreement or Brownfield Clean-up Agreement. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2013, an obligation of US$41 million was recognized in respect of MGP remediation and, based upon cost model analysis completed in 2012, it is estimated, with a 90% confidence level, that total costs to remediate these sites over the next 30 years will not exceed US$152 million.

Central Hudson has notified its insurers and intends to seek reimbursement from insurers for remediation, where coverage exists. Further, as authorized by the PSC, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for MGP site investigation and remediation and the associated rate allowances, with carrying charges to be accrued on the deferred balances at the authorized pre-tax rate of return.

Eltings Corners
Central Hudson owns and operates a maintenance and warehouse facility. In the course of Central Hudson's hazardous waste permit renewal process for this facility, sediment contamination was discovered within the wetland area across the street from the main property. Based on the investigation work completed by Central Hudson, the DEC and Central Hudson agreed in late 2013 that no additional investigation efforts are necessary. As requested by the DEC, Central Hudson submitted a draft Corrective Measures Study scoping document for review by the DEC. Although the extent of the contamination has now been established, the timing and costs for any future remediation efforts cannot be reasonably estimated at this time and, accordingly, no amount has been accrued in the 2013 Audited Consolidated Financial Statements.

Human Resources

As at December 31, 2013, Central Hudson employed 884 full-time equivalent employees. Approximately 60% of the employees are represented by IBEW under a collective agreement.

IBEW represents construction and maintenance employees, customer service representatives, service workers, and clerical employees, excluding employees in managerial, professional, or supervisory positions. The agreement with IBEW expires on April 30, 2017.

3.3 Regulated Electric Utilities - Canadian

3.3.1 *FortisAlberta*

FortisAlberta is a regulated electric distribution utility in the province of Alberta. Its business is the ownership and operation of regulated electricity distribution facilities that distribute electricity, generated by other market participants, from high-voltage transmission substations to end-use customers. The Company is not involved in the generation, transmission or direct sale of electricity. FortisAlberta operates the electricity distribution system in a substantial portion of southern and central Alberta, totalling approximately 118,000 kilometres of distribution lines. Many of the Company's customers are located in rural and suburban areas around and between the cities of Edmonton and Calgary. FortisAlberta's distribution network serves approximately 518,000 customers, comprising residential, commercial, farm, oil and gas and industrial consumers of electricity, and met a peak demand of 2,613 MW in 2013.

FortisAlberta's annual energy deliveries increased to 16,934 GWh in 2013 from 16,799 GWh in 2012. Revenue was $475 million in 2013 compared to $448 million in 2012.

As a significant portion of FortisAlberta's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

The following table compares the composition of FortisAlberta's 2013 and 2012 revenue and energy deliveries by customer class.

FortisAlberta Revenue and Energy Deliveries by Customer Class				
	Revenue (%)		**GWh Deliveries** [(1)] **(%)**	
	2013	2012	**2013**	2012
Residential	**29.6**	30.5	**17.0**	16.7
Large commercial, industrial and oil field	**20.8**	20.9	**61.3**	61.9
Farms	**11.8**	12.5	**7.6**	7.5
Small commercial	**10.5**	11.0	**7.9**	7.8
Small oil field	**8.3**	8.8	**5.8**	5.7
Other [(2)]	**19.0**	16.3	**0.4**	0.4
Total	**100.0**	100.0	**100.0**	100.0

(1) *GWh percentages presented exclude FortisAlberta's GWh deliveries to "transmission-connected" customers. These deliveries were 6,919 GWh in 2013 and 7,195 GWh in 2012 and consisted primarily of energy deliveries to large-scale industrial customers directly connected to the transmission grid.*

(2) *Includes revenue from sources other than the delivery of energy, including that related to street-lighting services, rate riders, deferrals and adjustments*

Franchise Agreements

FortisAlberta serves customers residing within various municipalities throughout its service areas through franchise agreements between the Company and the respective municipalities. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta located within their municipal boundaries. Upon the termination, or in the absence of a franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta) with the price to be as agreed by the Company and the municipality, failing which it is to be determined by the AUC. Additionally, under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric distribution system expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides that the AUC may determine that the municipality should pay compensation to the Company for any facilities transferred on the basis of replacement cost less depreciation. Given the historical population and economic growth of Alberta and its municipalities, FortisAlberta is affected by transactions of this type from time to time.

FortisAlberta holds franchise agreements with 140 municipalities within its service area. In 2012 FortisAlberta received approval of a new franchise agreement template from the AUC. The new template was filed with the AUC following negotiations with the Alberta Urban Municipalities Association and consultation with municipalities. The new franchise agreement template includes a 10-year term with an option that will permit the agreement to automatically renew for a further five years. To date, FortisAlberta converted 60 of the municipalities within its service area to the new franchise agreement, and intends to convert no less than 90% of all municipalities by the end of 2015.

Human Resources

As at December 31, 2013, FortisAlberta had 1,106 full-time equivalent employees. Approximately 75% of the employees of the Company are members of the UUWA. In December 2013 FortisAlberta reached an agreement on a new four-year collective agreement with UUWA that expires on December 31, 2017.

3.3.2 *FortisBC Electric*

FortisBC Electric 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 Company serves a diverse mix of approximately 164,000 customers, of whom approximately 128,000 are served directly by the Company's assets in communities that include Kelowna, Oliver, Osoyoos, Trail, Castlegar, Creston and Rossland, while the remainder are served through the wholesale supply of power to municipal distributors. In March 2013 FortisBC Electric purchased the City of Kelowna's electrical utility assets that now allow the Company to serve directly some 15,000 customers formerly served by the City of Kelowna. In 2013 FortisBC Electric met a peak demand of 699 MW. Residential customers represent the largest customer class of the Company. FortisBC Electric's T&D assets include approximately 7,150 kilometres of T&D lines and 65 substations.

FortisBC Electric also includes the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals and BC Hydro, the 149-MW Brilliant hydroelectric plant and 120-MW Brilliant hydroelectric expansion plant, both owned by CPC/CBT, and the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT.

Market and Sales

FortisBC Electric has a diverse customer base composed primarily of residential, commercial, industrial and municipal wholesale, and other industrial customers. Annual electricity sales increased to 3,211 GWh in 2013, from 3,143 GWh in 2012. Revenue increased to $317 million in 2013 from $306 million in 2012.

The following table compares the composition of FortisBC Electric's 2013 and 2012 revenue and electricity sales by customer class.

FortisBC Electric *(1)*
Revenue and Electricity Sales by Customer Class

	Revenue (%)		**GWh Sales (%)**	
	2013	2012	**2013**	2012
Residential	**50.1**	43.9	**45.3**	38.8
Commercial	**23.2**	21.1	**23.7**	23.2
Wholesale	**15.5**	20.3	**21.6**	28.7
Industrial	**8.5**	7.1	**9.4**	9.3
Other *(2)*	**2.7**	7.6	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Due to the acquisition of the City of Kelowna's electrical utility business in March 2013, FortisBC Electric serves directly some 15,000 customers formerly served by the City of Kelowna. As a result, revenue and GWh sales to residential, commercial and industrial customers increased for 2013 compared to 2012, and sales to wholesale customers decreased.*

(2) *Includes revenue from sources other than from the sale of electricity, including revenue of FortisBC Pacific Holdings associated with non-regulated operating, maintenance and management services*

Generation and Power Supply

FortisBC Electric meets the electricity supply requirements of its customers through a mix of its own generation and power purchase contracts. The Company owns four regulated hydroelectric generating plants on the Kootenay River with an aggregate capacity of 223 MW, which provide approximately 45% of the Company's energy needs and 30% of its peak capacity needs. FortisBC Electric meets the balance of its requirements through a portfolio of long-term and short-term PPAs.

FortisBC Electric's four hydroelectric generating facilities are governed by the CPA. The CPA is a multi-party agreement that enables the five separate owners of eight major hydroelectric generating plants, with a combined capacity of 1,565 MW and located in relatively close proximity to each other, to coordinate the operation and dispatch of their generating plants.

The following table lists the plants and their respective capacity and owner.

Plant	Capacity (MW)	Owners
Canal Plant	580	BC Hydro
Waneta Dam	493	Teck Metals and BC Hydro
Kootenay River System	223	FortisBC Electric
Brilliant Dam and Expansion	269	BPC and BEPC
Total	**1,565**	

BPC, BEPC, Teck Metals and FortisBC Electric are collectively defined in the CPA as the Entitlement Parties. 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 facilities, each of the Entitlement Parties is contractually entitled to a fixed annual entitlement of capacity and energy from BC Hydro, which is currently based on 50-year historical water flows. The Entitlement Parties receive their defined entitlements irrespective of actual water flows to the Entitlement Parties' generating plants and are, accordingly, insulated from the risk of water availability. Should the CPA be terminated, the output of FortisBC Electric's Kootenay River system plants would, with the water and storage authorized under its existing licences and on a long-term average, be approximately the same power output as FortisBC Electric receives under the CPA. The CPA does not affect FortisBC Electric's ownership of its physical generation 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.

The majority of FortisBC Electric's remaining electricity supply is acquired through long-term power purchase contracts, consisting of the following:

i. a 149-MW long-term PPA with BPC terminating in 2056 (Brilliant PPA);
ii. a 200-MW PPA with BC Hydro terminating in 2033 pending regulatory approval (BC Hydro PPA);
iii. a capacity and energy purchase agreement with CPC, acting on behalf of BEPC from 2013 through 2017 (Brilliant Expansion Capacity and Energy Purchase Agreement);
iv. a number of small power purchase contracts with independent power producers; and
v. a 40-year agreement to purchase capacity from the Waneta Expansion upon completion of construction, which is expected in spring 2015 (WECA).

The majority of the above purchase contracts have been accepted by the BCUC and prudently forecast and incurred costs, thereunder, flow through to customers through FortisBC Electric's electricity rates. Although the Company can meet the majority of its customer supply requirements from its own generation and the PPAs 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 such as spot market and contracted capacity purchases. Costs related to such purchases are recovered through customer electricity rates, provided they are prudently incurred.

Brilliant PPA
Under the Brilliant PPA, FortisBC Electric has agreed to purchase from BPC, on a long-term basis: (i) the entitlement allocated to the Brilliant hydroelectric plant; and (ii) after the expiration of the CPA, the actual electrical output generated by the Brilliant hydroelectric plant. While the total entitlement is 985,000 MWh, FortisBC Electric does not purchase the approximate 60,000 MWh of regulated flow upgrade entitlement. However, the Company has entered into another agreement with CPC for this energy over a five-year period, as discussed below. The Brilliant PPA uses a take-or-pay contract structure which requires that FortisBC Electric pay for the Brilliant hydroelectric plant's entitlement, irrespective of whether FortisBC Electric actually takes it. FortisBC Electric does not foresee any circumstances under which the Company would be required to pay for power that it does not require. During the first 30 years of the Brilliant PPA term, FortisBC Electric pays to BPC an amount that covers the operation and maintenance costs of the Brilliant hydroelectric 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 hydroelectric plant and

then-prevailing operating costs will be made to the amounts payable by FortisBC Electric. The Brilliant PPA provided the Company with approximately 26% of its energy requirements in 2013.

BC Hydro PPA
FortisBC Electric is a party to the BC Hydro PPA, which provides the Company with additional electricity for purposes of supplying its load requirements, up to a maximum demand of 200 MW. In 2013, energy bought pursuant to the BC Hydro PPA provided approximately 25% and 11% of FortisBC Electric's capacity and energy requirements respectively. The Company and BC Hydro have concluded negotiations on a replacement of the agreement for an additional 20-year term, which is currently pending BCUC approval. The term of the current BC Hydro PPA, which terminated in 2013, has been extended until the beginning of the month following BCUC approval.

Brilliant Expansion Capacity and Energy Purchase Agreement
In November 2012 FortisBC Electric entered into an agreement to purchase capacity and energy from 2013 through 2017 from CPC acting on behalf of BPC. The agreement was accepted by the BCUC in December 2012. The agreement allows FortisBC Electric to purchase CPC's unused CPA entitlements from the Brilliant hydroelectric plant and the Brilliant hydroelectric expansion plant, including the 60,000 MWh from the Brilliant hydroelectric plant that is not included in the Brilliant PPA. The agreement is for a total of 78,500 MWh and provided approximately 2% of FortisBC Electric's energy requirements in 2013.

Small Power Purchase Contracts
FortisBC Electric has a number of small power purchase contracts with independent power producers, which collectively provided approximately 1% of the Company's energy supply requirements in 2013. The majority of these contracts have been accepted by the BCUC.

Spot Market and Contracted Capacity Purchases
During 2013 FortisBC Electric entered into various arrangements to purchase capacity and energy from the market to meet its peak energy requirements and optimize its overall power supply portfolio. 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 Company entered into an agreement to purchase fixed price, winter capacity through to February 2016 to assist in mitigating risks of market volatility and availability. Spot market contracted purchases provided approximately 15% of FortisBC Electric's energy supply requirements in 2013.

WECA
In November 2011 FortisBC Electric executed the WECA to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected in spring 2015. In May 2012 the BCUC determined that the executed agreement was accepted for filing as an energy supply contract and is in the public interest. The Waneta Expansion is included in the CPA and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing hydrologic risk associated with the project. The energy, approximately 630 GWh on an annual basis, and associated capacity required to deliver such energy for the Waneta Expansion, will be sold to BC Hydro under a long-term energy purchase agreement. The surplus capacity, equal to 234 MW on an average annual basis, will be sold to FortisBC Electric over 40 years under the WECA. For additional information, refer to Section 3.5 of this 2013 Annual Information Form.

Legal Proceedings

The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake in 2003, prior to the acquisition of FortisBC Electric by Fortis, and has filed and served a writ and statement of claim against FortisBC Electric dated August 2, 2005. The Government of British Columbia has disclosed that its claim includes approximately $15 million in damages as well as pre-judgment interest, but that it has not fully quantified its damages. FortisBC Electric and its insurers continue to defend the claim by the Government of British Columbia. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the 2013 Audited Consolidated Financial Statements.

The Government of British Columbia filed a claim in the British Columbia Supreme Court in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which include FortisBC Electric, use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $15 million. While FortisBC Electric has not been served, the Company has retained counsel and has notified its insurers. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the 2013 Audited Consolidated Financial Statements.

Human Resources

As at December 31, 2013, FortisBC Electric had 310 full-time equivalent employees. The full-time equivalent was impacted by the labour action as discussed below. Approximately 65% of the employees are represented by the IBEW and COPE. The four-year collective agreement between the Corporation and IBEW expired on January 31, 2013. IBEW represents employees in specified occupations in the areas of generation and T&D. The parties commenced negotiations in January 2013, and in March 2013 the IBEW served the Corporation 72 hours' strike notice and commenced partial job action on May 16, 2013. The labour disruption ended in December 2013 when the IBEW and FortisBC Electric agreed to binding interest arbitration. The arbitration process is scheduled to occur over the first half of 2014.

There are two collective agreements between FortisBC Electric and COPE. For the first COPE collective agreement, representing employees in specified occupations in the areas of administration and operations support, a new five-year agreement came into effect on January 1, 2014 and expires on December 31, 2018. The second COPE collective agreement, representing customer service employees, expires on March 31, 2014; however, FortisBC Electric has negotiated an agreement with COPE, subject to ratification, that expires on March 31, 2017.

3.3.3 *Newfoundland Power*

Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving approximately 256,000 customers, or 87%, of the province's electricity consumers in approximately 600 communities. Newfoundland Power met a peak demand of 1,281 MW in 2013. The balance of the population is served by Newfoundland and Labrador's other electric utility, Newfoundland Hydro, which also serves several larger industrial customers. Newfoundland Power owns and operates approximately 11,700 kilometres of T&D lines.

Market and Sales

Annual electricity sales increased to 5,763 GWh in 2013 from 5,652 GWh in 2012. Revenue increased to $601 million in 2013 from $581 million in 2012.

The following table compares the composition of Newfoundland Power's 2013 and 2012 revenue and electricity sales by customer class.

Newfoundland Power Revenue and Electricity Sales by Customer Class				
	Revenue (1) **(%)**		**GWh Sales** (1) **(%)**	
	2013	2012	**2013**	2012
Residential	**61.5**	60.1	**61.3**	60.9
Commercial	**36.1**	36.2	**38.7**	39.1
Other (2)	**2.4**	3.7	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Revenue and electricity sales reflect weather-adjusted values pursuant to Newfoundland Power's weather normalization reserve.*

(2) *Includes revenue from sources other than from the sale of electricity, including revenue deferrals*

Power Supply

Approximately 93% of Newfoundland Power's energy requirements are purchased from Newfoundland Hydro. The principal terms of the supply arrangements with Newfoundland Hydro are regulated by the PUB on a basis similar to that upon which Newfoundland Power's service to its customers is regulated.

The purchased power rate structure is the basis upon which Newfoundland Hydro charges Newfoundland Power for purchased power and includes charges for both demand and energy purchased. The demand charge is based on applying a rate to the peak-billing demand for the most recent winter season. The energy charge is a two-block charge with a higher second-block charge set to reflect Newfoundland Hydro's marginal cost of generating electricity.

The PUB is currently considering a Newfoundland Hydro General Rate Application which will, amongst other things, establish wholesale rates for Newfoundland Power. The PUB is expected to rule on Newfoundland Hydro's General Rate Application in 2014.

In early January 2014 there was a shortage of generation supply and a series of major electrical disturbances on the electrical system which serves the island of Newfoundland. The PUB commenced an inquiry and hearing process into the supply issues and power interruptions experienced. Newfoundland Power is a party to the PUB process. The PUB indicated that it intends to issue an interim report on the matter by May 2014 and a final report in the first quarter of 2015.

Newfoundland Power operates 28 small generating facilities, which generate approximately 7% of the electricity sold by the Company. Newfoundland Power's hydroelectric generating plants have a total capacity of 97 MW. The diesel plants and gas turbines have a total capacity of approximately 5 MW and 37 MW, respectively.

Human Resources

As at December 31, 2013, Newfoundland Power had 656 full-time equivalent employees, of which approximately 55% were members of bargaining units represented by IBEW.

The Company has two collective agreements governing its union employees represented by IBEW. One bargaining unit is composed predominately of clerical employees and the other predominately of skilled trades and outside workers. Both collective agreements expire on September 30, 2014.

3.3.4 *Other Canadian Electric Utilities*

Other Canadian Electric Utilities are comprised of the operations of Maritime Electric and FortisOntario.

Maritime Electric
The Corporation, through FortisWest, holds all of the common shares of Maritime Electric. Maritime Electric is an integrated electric utility that directly supplies approximately 77,000 customers, constituting approximately 90% of electricity consumers on PEI. Maritime Electric purchases most of the energy it distributes to its customers from NB Power, a New Brunswick Crown corporation, through various energy purchase agreements. The Company also purchases energy from Island-based wind-powered generation owned by the PEI Energy Corporation, a provincial Crown corporation. Maritime Electric's electricity system is connected to the mainland power grid via two submarine cables between PEI and New Brunswick, which are leased from the Government of PEI. Maritime Electric owns and operates generating plants with a combined capacity of 150 MW on PEI and met a peak demand of 252 MW in 2013. Maritime Electric owns and operates approximately 5,700 kilometres of T&D lines.

FortisOntario
The Corporation's wholly owned regulated utility investments in Ontario, collectively FortisOntario, provide integrated electric utility service to approximately 65,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations are comprised of Canadian Niagara Power, Cornwall Electric and Algoma Power. FortisOntario also owns a 10% interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies serving approximately 38,000 customers. FortisOntario met a combined peak demand of 271 MW in 2013. FortisOntario owns and operates approximately 3,300 kilometres of T&D lines.

Market and Sales

Annual electricity sales were 2,405 GWh in 2013 compared to 2,381 GWh in 2012. Revenue was $374 million in 2013 compared to $353 million in 2012.

The following table compares the composition of Other Canadian Electric Utilities' 2013 and 2012 revenue and electricity sales by customer class.

Other Canadian Electric Utilities Revenue and Electricity Sales by Customer Class				
	Revenue (%)		**GWh Sales (%)**	
	2013	2012	**2013**	2012
Residential	**45.1**	43.6	**44.8**	43.1
Commercial and Industrial	**48.1**	49.0	**54.6**	56.6
Other [(1)]	**6.8**	7.4	**0.6**	0.3
Total	**100.0**	100.0	**100.0**	100.0

[(1)] *Includes revenue from sources other than from the sale of electricity*

Power Supply

Maritime Electric

Maritime Electric purchased 84% of the electricity required to meet its customers' needs from NB Power in 2013. The balance was met through the purchase of wind energy produced on PEI by stations owned by the PEI Energy Corporation and from Company-owned on-Island generation. Maritime Electric's on-Island generation facilities are used primarily for peaking, submarine-cable loading issues and emergency purposes.

Maritime Electric has two take-or-pay contracts for the purchase of either energy or capacity. In 2010 the Company signed a five-year take-or-pay contract with NB Power covering the period March 1, 2011 through February 29, 2016. The contract includes fixed pricing for the entire five-year period. The other take-or-pay contract, which is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on an international power line into the United States, expires in November 2032.

Maritime Electric has entitlement to approximately 4.7% of the output from Point Lepreau for the life of the unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital and operating costs of the unit. A major refurbishment of Point Lepreau that began in 2008 was completed and the station returned to service in November 2012. The refurbishment is expected to extend the facility's estimated life for an additional 27 years.

The *Renewable Energy Act* (PEI) requires Maritime Electric to supply 15% of its annual energy sales from renewable energy sources. In 2013 approximately 17% of Maritime Electric's annual energy sales requirement was supplied by renewable energy.

FortisOntario

The power requirements of FortisOntario's service areas are provided from various sources. Canadian Niagara Power purchases its power requirements for Fort Erie and Port Colborne from IESO. Canadian Niagara Power purchases approximately 88% of energy requirements for Gananoque through monthly energy purchases from Hydro One and the remaining 12% is purchased, through the Hydroelectric Contract Initiative, from the five hydroelectric generating plants of the Fortis Generation East Partnership. Algoma Power purchases 100% of its energy from IESO.

Under the Standard Supply Code of the OEB, Canadian Niagara Power and Algoma Power are obliged to provide Standard Service Supply to all its customers who do not choose to contract with an electricity retailer. This energy is provided to customers at either regulated or market prices.

Cornwall Electric purchases substantially all of its power requirements from Hydro-Québec Energy Marketing under two fixed-term contracts. The first contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per year. Both contracts expire in December 2019.

Human Resources

As at December 31, 2013, Maritime Electric had 175 full-time equivalent employees, of which approximately 70% were represented by IBEW. A new collective agreement was ratified in November 2013 and is effective from January 1, 2014 to December 31, 2018.

As at December 31, 2013, FortisOntario had 200 full-time equivalent employees, of which approximately 59% were represented by CUPE, in Cornwall; IBEW in the Niagara region and Gananoque; and Power Workers Union, a CUPE affiliate, in the Algoma region. The expiry dates of the collective agreements are April 30, 2016; February 29, 2016 and July 31, 2016; and December 31, 2016, respectively.

3.4 Regulated Electric Utilities - Caribbean

Regulated Electric Utilities - Caribbean operations are comprised of Caribbean Utilities and Fortis Turks and Caicos.

Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 27,000 customers. The Company met a peak demand of approximately 97 MW in 2013. Caribbean Utilities owns and operates approximately 704 kilometres of T&D lines, including 25 kilometres of submarine cable. Fortis holds an approximate 60% (December 31, 2012 - 60%) controlling ownership interest in the utility. Caribbean Utilities is a public company traded on the TSX (TSX:CUP.U).

Fortis Turks and Caicos is comprised of FortisTCI and TCU and is the principal distributor of electricity in the Turks and Caicos Islands. Each of the Fortis Turks and Caicos utilities is an integrated electric utility and, combined, serve approximately 13,000 customers, or 98% of electricity consumers, in the Turks and Caicos Islands. The utilities met a combined peak demand of approximately 36 MW in 2013. Fortis Turks and Caicos owns and operates approximately 618 kilometres of T&D lines.

Market and Sales

Annual electricity sales were 749 GWh in 2013 compared to 728 GWh in 2012. Revenue was $290 million in 2013 compared to $273 million in 2012.

The following table compares the composition of Regulated Electric Utilities - Caribbean's revenue and electricity sales by customer class for 2013 and 2012.

Regulated Electric Utilities - Caribbean
Revenue and Electricity Sales by Customer Class

	Revenue (%)		**GWh Sales (%)**	
	2013	2012	**2013**	2012
Residential	**44.7**	44.7	**42.6**	42.4
Commercial and Industrial	**53.9**	54.2	**57.4**	57.6
Other (1)	**1.4**	1.1	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes revenue from sources other than from the sale of electricity*

Power Supply

Caribbean Utilities relies upon in-house diesel-powered generation to produce electricity for Grand Cayman. Grand Cayman has neither hydroelectric potential nor inherent thermal resources and the Company must rely upon diesel fuel imported to Grand Cayman primarily from refineries in the Caribbean and the Gulf of Mexico. The Company has an installed generating capacity of approximately 150 MW.

In 2012 Caribbean Utilities entered into primary and secondary fuel supply contracts with two different suppliers and is committed to purchasing approximately 60% and 40%, respectively, of the Company's diesel fuel requirements under each of the contracts. The contracts expire in July 2014 with the option to renew for two additional 18-month terms. Caribbean Utilities also entered into a five-year contract for the supply of lube oil. These contracts enable Caribbean Utilities to purchase fuel and lube oil from the suppliers on what the Company believes to be competitive terms and pricing.

Both the fuel and lube oil contracts include disaster recovery and business continuity plans in the event of foreseeable disruptions to supplies to reduce the impact on Caribbean Utilities' operations.

Fortis Turks and Caicos relies upon in-house diesel-powered generation, with an installed generating capacity of 76 MW, to produce electricity for its customers.

FortisTCI has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

Human Resources

As at December 31, 2013, Regulated Electric Utilities - Caribbean employed 340 full-time equivalent employees. The 190 employees at Caribbean Utilities and 150 employees at Fortis Turks and Caicos are non-unionized.

3.5 Non-Regulated - Fortis Generation

The following table summarizes the Corporation's non-regulated generation assets by location.

Non-Regulated - Fortis Generation Assets			
Location	**Plants**	**Fuel**	**Capacity (MW)**
Belize	3	hydro	51
Ontario	7	hydro, thermal	13
British Columbia [(1)]	1	hydro	16
Upstate New York	4	hydro	23
Total	**15**		**103**

(1) *Once completed, the Waneta Expansion will provide an additional 335 MW of hydroelectric generating capacity in British Columbia.*

The Corporation's non-regulated generation operations consist of its 100% ownership interest in each of BECOL, FortisOntario, Fortis Generation East Partnership, and FortisUS Energy, as well as non-regulated generation assets owned by FortisBC Inc. and by Fortis through its 51% controlling ownership interest in the Waneta Partnership.

Non-regulated generation operations in Belize consist of the 25-MW Mollejon, 7-MW Chalillo and 19-MW Vaca hydroelectric generating facilities. All of the output of these facilities is sold to Belize Electricity under 50-year PPAs expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary BECOL under a franchise agreement with the GOB. In October 2011 the GOB purportedly amended the Constitution of Belize to require majority government ownership of three public utility providers, including Belize Electricity, but excluding BECOL. The GOB has also indicated it has no intention to expropriate BECOL. Fortis continues to control and consolidate the financial statements of BECOL.

Non-regulated generation operations of FortisOntario are comprised of the operation of a 5-MW gas-powered cogeneration plant in Cornwall. All thermal energy output of this plant is sold to external third parties, while the electricity output is sold to Cornwall Electric. Fortis Generation East Partnership owns and operates six small hydroelectric generating facilities in eastern Ontario with a combined capacity of 8 MW. The electricity produced from these facilities is sold to the Ontario Power Authority, via the Hydroelectric Contract Initiative, under fixed-price contracts.

The non-regulated generation operations of FortisBC Inc. include the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia which is selling its entire output to BC Hydro. The contract with BC Hydro expired in 2013 and is subject to termination by BC Hydro with five months' notice. Non-regulated generation operations in British Columbia also include the Corporation's 51% controlling ownership interest in the Waneta Partnership, with CPC/CBT holding the remaining 49% interest. Fortis will operate and maintain the non-regulated investment when the facility comes into service, which is expected in spring 2015.

The Waneta Partnership commenced construction of the $900 million, 335-MW Waneta Expansion in late 2010, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia. The project is currently on schedule and within budget. Approximately $579 million in total has been spent on the Waneta Expansion since construction began, with $143 million spent in 2013. Key construction activities in 2013 included the substantial completion of civil construction of the powerhouse and tailrace structure; significant progress on the intake structure; installation of the turbine components, ancillary mechanical and electrical powerhouse services; and encapsulating of the scrollcase in concrete. During 2013, the generator step-up transformers and the first turbine runner were received on site for assembly and installation. The key offsite activity in 2013 was the successful completion of the manufacturing of the first turbine runner and turbine operating mechanism. In 2014 approximately $126 million is expected to be spent. Key project activities scheduled for 2014 include energization of the 230-kilovolt transmission line; completion of civil construction work; installation and assembly of the major components of the first and second turbine/generator units; installation of protection and control systems; and testing and commissioning. The first unit marketable power test is forecast to be completed in the fourth quarter of 2014. For additional information refer to Section 3.3.2 of this 2013 Annual Information Form.

Through FortisUS Energy, an indirectly wholly owned subsidiary, the Corporation owns and operates four hydroelectric generating facilities in Upstate New York with a combined capacity of approximately 23 MW operating under licences from FERC. All four hydroelectric generating facilities sell energy at market rates through purchase agreements with Niagara Mohawk Power Corporation.

Market and Sales

Annual energy sales from non-regulated generation assets were 386 GWh in 2013 compared to 306 GWh in 2012. Revenue was $35 million in 2013 compared to $31 million in 2012.

The following table compares the composition of Fortis Generation's 2013 and 2012 revenue and energy sales by location.

Non-Regulated - Fortis Generation Revenue and Energy Sales by Location				
	Revenue (%)		GWh Sales (%)	
	2013	2012	**2013**	2012
Belize	**72.5**	70.2	**64.2**	65.1
Ontario	**15.6**	13.0	**13.1**	12.9
British Columbia	**5.4**	6.8	**7.9**	11.4
Upstate New York	**6.5**	5.5	**14.8**	10.6
Central Newfoundland (1)	**-**	4.5	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) Reflects the discontinuance of the consolidation method of accounting for the financial results of the operations in central Newfoundland, effective February 12, 2009. In March 2013 the Corporation and the Government of Newfoundland and Labrador settled all matters pertaining to the expropriation of non-regulated hydroelectric generating assets and water rights in Central Newfoundland.

Human Resources

As at December 31, 2013, Fortis Generation employed 40 full-time equivalent employees, none of whom participate in a collective agreement.

3.6 Non-Regulated – Non-Utility

Non-Utility investments are comprised of Fortis Properties and Griffith.

Fortis Properties

As a wholly owned subsidiary of Fortis, Fortis Properties is the Corporation's vehicle for non-utility diversification and growth. The Company owns and operates 23 hotels, comprised of more than 4,400 rooms, in eight Canadian provinces, and approximately 2.7 million square feet of commercial office and retail space, primarily in Atlantic Canada. Fortis Properties is currently constructing a 12-storey office building in downtown St. John's, Newfoundland and Labrador, for approximately $50 million. The building will feature 157,000 square feet of Class A office space. Construction is expected to be completed in the third quarter of 2014.

Revenue was $248 million in 2013 compared to $242 million in 2012. In 2013 Fortis Properties derived approximately 28% of its revenue from real estate operations and 72% of its revenue from hotel operations. Fortis Properties derived approximately 42% of its 2013 operating income from real estate operations and 58% from hotel operations.

Fortis Properties' Real Estate Division is anchored by high-quality tenants under long-term leases. The Real Estate Division ended 2013 with 92.5% occupancy, compared to 91.9% occupancy at the end of 2012. In contrast, the average national occupancy rate was 90.3% at the end of 2013, compared to 91.5% at the end of 2012.

The following table sets out the office and retail properties owned by Fortis Properties.

Fortis Properties Office and Retail Properties			
Property	**Location**	**Type of Property**	**Gross Lease Area** *(000's square feet)*
Fort William Building	St. John's, NL	Office	188
Cabot Place I	St. John's, NL	Office	136
TD Place	St. John's, NL	Office	100
Fortis Building	St. John's, NL	Office	83
Multiple Office	St. John's, NL	Office and Retail	60
Millbrook Mall	Corner Brook, NL	Retail	118
Fraser Mall	Gander, NL	Retail	99
Marystown Mall	Marystown, NL	Retail	93
Fortis Tower	Corner Brook, NL	Office	68
Maritime Centre	Halifax, NS	Office and Retail	560
Brunswick Square	Saint John, NB	Office and Retail	513
Kings Place	Fredericton, NB	Office and Retail	293
Blue Cross Centre	Moncton, NB	Office and Retail	325
Delta Regina	Regina, SK	Office	52
Total			**2,688**

Revenue per available room at the Hospitality Division of Fortis Properties was $81.48 for 2013 up from $80.00 for 2012. The increase was the result of a 2.2% increase in average daily room rate, partially offset by a 0.3% decrease in hotel occupancy. The average daily room rate increased to $132.70 for 2013 from $129.79 for 2012, while the average occupancy for 2013 was 61.4%, down from the 61.6% achieved in 2012.

The hotels owned and managed by Fortis Properties are summarized as follows.

Fortis Properties Hotels			
Hotels	**Location**	**Number of Guest Rooms**	**Conference Facilities** *(000's square feet)*
Delta St. John's	St. John's, NL	403	21
Holiday Inn St. John's	St. John's, NL	252	12
Sheraton Hotel Newfoundland	St. John's, NL	301	18
Mount Peyton	Grand Falls-Windsor, NL	149	5
Greenwood Inn Corner Brook	Corner Brook, NL	102	5
Four Points by Sheraton Halifax	Halifax, NS	177	12
Holiday Inn Sydney - Waterfront	Sydney, NS	152	6
Delta Brunswick	Saint John, NB	254	18
Holiday Inn Kitchener - Waterloo	Kitchener-Waterloo, ON	184	13
Holiday Inn Peterborough	Peterborough, ON	153	7
Holiday Inn Sarnia	Point Edward, ON	216	11
Holiday Inn Cambridge	Cambridge, ON	143	7
Holiday Inn & Suites Windsor	Windsor, ON	214	17
Greenwood Inn Calgary	Calgary, AB	210	9
StationPark All Suite Hotel	London, ON	126	2
Holiday Inn Edmonton	Edmonton, AB	224	8
Best Western Plus Winnipeg *(1)*	Winnipeg, MB	213	8
Hilton Suites Winnipeg Airport	Winnipeg, MB	159	9
Holiday Inn Lethbridge	Lethbridge, AB	119	5
Holiday Inn Express and Suites Medicine Hat	Medicine Hat, AB	93	1
Best Western Medicine Hat	Medicine Hat, AB	122	-
Holiday Inn Express Kelowna	Kelowna, BC	190	5
Delta Regina	Regina, SK	274	24
Total		**4,430**	**223**

(1) *In November 2013 the Greenwood Inn Winnipeg was rebranded to Best Western Plus Winnipeg.*

Human Resources

As at December 31, 2013, Fortis Properties employed approximately 2,400 full-time equivalent employees, approximately 46% of whom are represented by unions listed in the following table.

Fortis Properties Unions			
Property	**Union**	**Expiry of Agreement**	**Number of Unionized Employees**
Holiday Inn St. John's	CAW	August 31, 2015	55
Delta St. John's	UFCW	December 31, 2016	240
Greenwood Inn Corner Brook	CAW	March 11, 2016	45
East Side Mario's St. John's	CAW	July 31, 2016	98
Holiday Inn Sydney - Waterfront	CAW	September 30, 2014	70
Delta Brunswick & Brunswick Square	USW	June 30, 2016	122
Delta Regina	CEP	May 31, 2014	166
St. John's Real Estate	IBEW	April 17, 2016	7
Sheraton Hotel Newfoundland	CAW	March 31, 2015	188
Holiday Inn & Suites Windsor	UFCW	April 30, 2016	48
Mount Peyton	UFCW	December 1, 2014	56
Total			**1,095**

Griffith

On June 27, 2013 Fortis acquired all of the outstanding common shares of CH Energy Group. CH Energy Group's non-regulated operations primarily consist of Griffith, which mainly supplies petroleum products and related services to approximately 60,000 customers in the Mid-Atlantic Region of the United States. In March 2014 CH Energy Group sold Griffith.

As at December 31, 2013, Griffith employed 355 full-time equivalent employees, none of whom participate in a collective agreement.

4.0 REGULATION

The Corporation's utilities primarily operate under a cost of service methodology and are regulated by the regulatory body in its respective operating jurisdiction. With regulated utilities in eight different jurisdictions, Fortis has significant regulatory expertise.

For information with respect to the nature of regulation and material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities, refer to the "Regulatory Highlights" section of the Corporation's MD&A and to Note 2 of the Corporation's 2013 Audited Consolidated Financial Statements.

5.0 ENVIRONMENTAL MATTERS

The Corporation and its subsidiaries are subject to various federal, provincial, state and municipal laws, regulations and guidelines relating to the protection of the environment including, but not limited to, wildlife, water and land protection, emissions and the proper storage, transportation, recycling and disposal of hazardous and non-hazardous substances. In addition, federal, provincial and state 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 their commencement.

Several key Canadian federal environmental laws and regulations affecting the operations of the Corporation's Canadian subsidiaries include, but are not limited to, the: (i) *Canadian Environmental Assessment Act, 2012;* (ii) *Canadian Environmental Protection Act, 1999*; (iii) *Transportation of Dangerous Goods Act and Regulations*; (iv) *Hazardous Products Act*; (v) *Canada Wildlife Act*; (vi) *Navigable Waters Protection Act*; (vii) *Canada National Parks Act*; (viii) *Fisheries Act;* (ix) *Canada Water Act;* (x) *National Fire Code of Canada;* (xi) *Pest Control Products Act and Regulations;* (xii) *PCB Regulations;* (xiii) *Species at Risk Act;* (xiv) *Ozone Depleting Substances Regulations;* (xv) *Indian Act;* (xvi) *International River Improvement Act;* and (xvii) *Migratory Birds Convention Act.*

Several key U.S. federal environmental laws and regulations affecting the operations of Central Hudson include, but are not limited to, the: (i) *Clean Water Act*; (ii) *Safe Drinking Water Act*; (iii) *Clean Air Act*; (iv) *Endangered Species Act*; (v) *Resource Conservation & Recovery Act*; (vi) *Toxic Substances Control Act*; (vii) *Comprehensive Environmental Response, Compensation, and Liability Act*; (viii) *National Environmental Policy Act*; (ix) *Emergency Planning & Community Right to Know Act*; and (x) *Pollution Prevention Act of 1990*.

Environmental risks affecting the Corporation's utility operations include, but are not limited to: (i) hazards associated with the transportation, storage and handling of large volumes of fuel for fuel-powered electricity generating plants, including leeching of the fuel into the ground, nearby watershed areas and open waters; (ii) risk of spills or leaks of petroleum-based products, including PCB-contaminated oil, which are used in the cooling and lubrication of transformers, capacitors and other electrical equipment; (iii) risk related to natural gas discharges; (iv) risk of spills or releases into the environment arising from the improper transportation, storage, handling and disposal of other hazardous substances; (v) GHG emissions, including natural gas and propane leaks and spills and emissions from the combustion of fuel required to generate electricity; (vi) risk of fire; (vii) risk of disruption to vegetation; (viii) risk of contamination of soil and water near chemically treated poles; (ix) risk of disruption to fish, animals and their habitat as a result of the creation of artificial water flows and levels associated with hydroelectric water storage and utilization; and (x) risk of responsibility for remediation of contaminated properties, whether or not such contamination resulted from the Corporation's utility operations.

There are many provincial, state, and municipal laws, regulations and guidelines that address similar environmental risks as the federal laws, regulations and guidelines, but at a provincial, state or local level. The constant evolution of environmental legislation results in ongoing risks to the Corporation, as its subsidiaries must adjust their business operations to comply.

In addition to changing air emission standards, the management of GHG emissions is a specific environmental concern of the Corporation's Regulated Utilities in Canada, primarily due to the uncertainties relating to new and emerging federal, provincial and state GHG laws, regulations and guidelines. Governmental policy direction is unfolding, however, it remains to be determined whether a GHG air emissions cap may be imposed and to what extent it will impact these utilities. Both Canada and the United States have committed to reduce GHG emissions to 17% below 2005 levels by 2020. Both countries are in the process of imposing sectoral requirements, yet it is not certain how the Corporation's subsidiaries will be impacted.

In British Columbia, the *Carbon Tax Act, Clean Energy Act, Greenhouse Gas Reduction (Cap and Trade) Act* and *Greenhouse Gas Reduction Targets Act* and anticipated cap-and-trade regulations specifically affect, or may potentially affect, the operations of the FortisBC Energy companies and FortisBC Electric. To help mitigate uncertainty, the FortisBC Energy companies participate in sector and industry groups in order to monitor the development of emerging regulation and policy.

The Government of British Columbia's Energy Plan and GHG reduction targets present risks and opportunities to the FortisBC Energy companies and, to a lesser degree, FortisBC Electric. These government initiatives continue to place pressure on natural gas consumption and its contribution to GHG emissions. The energy and GHG emissions policies in British Columbia have created opportunities for FEI through incentives to expand FEI's deployment of renewable energy, such as biogas, the establishment of a natural gas transportation program, and the expansion of its Energy Efficiency and Conservation Program. Additionally, the *Carbon Tax Act* improves the competitive position of natural gas relative to other fossil fuels, as the tax is based on the amount of carbon dioxide equivalent emitted per unit of energy. Natural gas, therefore, has a lower tax rate than oil or coal products.

British Columbia continues to be a participant in the Western Climate Initiative, which expects to implement a cap-and-trade program to reduce GHG emissions. FEI and FEVI are expected to be covered under the program. If implemented, the cap-and-trade program is expected to have a declining cap on emissions that all applicable facilities must meet, either by reducing emissions internally or by purchasing allowances from other facilities for release of GHG emissions over the capped amounts.

In 2011 the FortisBC Energy companies began reporting their GHG emissions pursuant to the reporting regulation under the *Greenhouse Gas Reduction (Cap and Trade) Act.* In addition, the FortisBC Energy companies continue to report their GHG emissions under Environment Canada's GHG Reporting Program. The FortisBC Energy companies have developed capabilities that will support the management of compliance requirements in an upcoming GHG emissions' trading environment, as government policy in that area evolves. The Companies will also continue to monitor and assess emerging regulations, in particular, the offset and allowance regulations.

The impact of GHG emissions is lower at the Corporation's Canadian Regulated Electric Utilities because their primary business is the distribution of electricity. With respect to FortisAlberta, its operations involve only the distribution of electricity. Additionally, all in-house generating capacity at FortisBC Electric, about 70% at Newfoundland Power, and most of the Corporation's non-regulated generating capacity is hydroelectric, a clean energy source. The 335-MW Waneta Expansion will be a clean renewable hydroelectric energy source when it comes into service in spring 2015. Only a small portion of in-house generation at Canadian Regulated Electric Utilities uses diesel fuel. The Corporation's Canadian Regulated Electric Utilities are indirectly impacted, however, by GHG emissions through the purchase of power generated by suppliers using combustible fuel. Such power suppliers are responsible for compliance with carbon dioxide emissions standards and the cost of compliance with such standards is generally flowed through to end-use consumers.

The *Renewable Energy Act* (PEI) and the recent PEI Energy Accord directly impact the long-term energy supply planning process for the province of PEI. The Act required Maritime Electric to source 15% of its annual energy sales from renewable sources by 2010, which the Company met in both 2012 and 2013. Under the PEI Energy Accord, Maritime Electric and the Government of PEI are committed to work collaboratively to increase electricity produced on PEI and sold to Maritime Electric from renewable energy sources, principally wind.

Central Hudson is subject to regulation by federal, state and local authorities related to the environmental effects of its operations. The Company owns minimal generating capacity and relies on purchased capacity and energy from third-party providers. Central Hudson is, however, exposed to environmental contingencies associated with MGP's that it and its predecessors owned and operated to serve their customers' heating and lighting needs from the mid- to late 1800s to the 1950s. The DEC regulates the timing and extent of remediation of MGP sites in New York State. As at December 31, 2013, Central Hudson has recognized approximately US$41 million in associated MGP environmental remediation liabilities. As approved by the PSC, the Company is currently permitted to recover MGP site investigation and remediation costs in customer rates. For additional information, refer to the "3.2.1 Central Hudson" section of this 2013 Annual Information Form.

While there are environmental laws, regulations and guidelines affecting the Corporation's operations in Grand Cayman and Turks and Caicos Islands, they are less extensive than the laws, regulations and guidelines in Canada. The United Kingdom's ratification of the United Nations Framework Convention on Climate Change and its Kyoto Protocol were extended to the Cayman Islands in 2007. This framework aims to reduce GHG emissions produced by certain industries. Specific details on the regulations implementing the protocol have yet to be released by the local government of the Cayman Islands and, accordingly, Caribbean Utilities is currently unable to assess the financial impact of compliance with the framework of the protocol.

All of the energy requirements of Caribbean Utilities and Fortis Turks and Caicos are sourced from in-house diesel-powered generation. The more recently installed generators at Caribbean Utilities and Fortis Turks and Caicos have also been designed to provide an increased output per gallon consumed than the older generators, which generate electricity in a more efficient and environmentally friendly manner. The height of exhaust stacks have been increased and improved exhaust systems installed to maximize sound attenuation, and optimize exhaust plume dispersion thereby improving local air quality in accordance with what the utilities believe to be the best industry practice. The use of diesel oil versus heavy fuel oil also results in significantly lower levels of exhaust emissions. The utilities also purchase and store diesel fuel and/or lubricating oil in bulk thereby decreasing the environmental risks associated with fuel and/or oil handling. Investments have been made in containment areas for the bulk storage of diesel fuel which have been designed to prevent the fuel from coming into contact with soil or groundwater. Caribbean Utilities also uses an underground fuel pipeline for the delivery of fuel from suppliers' distribution terminals on the coast of Grand Cayman to the day-tank holding facilities at the Company's generating plant. The pipeline eliminates the need for road transport of fuel along coastline roads.

The key focus of the utilities is to provide reliable cost-effective service with full regard for the safety of employees and the public while operating in an environmentally responsible manner. A focus on safety and the environment is, therefore, an integral and continuing component of the Corporation's operating activities.

Each of the Corporation's utilities has an EMS, with the exception of Fortis Turks and Caicos which expects to complete the implementation of its EMS by the end of 2014. Environmental policies form the cornerstone of the EMS and outline the following commitments by each utility and its employees with respect to conducting business in a safe and environmentally responsible manner: (i) meet and comply with all applicable laws, legislation, policies, regulations and accepted standards of environmental protection; (ii) manage activities consistent with industry practice and in support of the environmental policies of all levels of government; (iii) identify and manage risks to prevent or reduce adverse consequences from operations, including preventing pollution and conserving natural resources; (iv) regular environmental monitoring and audits of the EMS and striving for continual improvement in environmental performance; (v) regularly set and review environmental objectives, targets and programs; (vi) communicate openly with stakeholders including making available the utility's environmental policy and knowledge of environmental issues to customers, employees, contractors and the general public; (vii) support and participate in community based projects that focus on the environment; (viii) provide training for employees and those working on behalf of the utility to enable them to fulfill their duties in an environmentally responsible manner; and (ix) work with industry associations, government and other stakeholders to establish standards for the environment appropriate to the utility's business.

Through an EMS, documented procedures are in place to control activities that can affect the environment. Common elements of the utilities' EMSs include: (i) regular inspections of fuel and oil-filled equipment in order to identify and correct for potential spills, and spill response systems to ensure that all spills are addressed, and the associated cleanup is conducted in a prompt and environmentally responsible manner; (ii) GHG emissions management; (iii) procedures for handling, transporting, storing and disposing of hazardous substances, including chemically treated poles, asbestos, lead and mercury, where applicable; (iv) programs to mitigate fire-related incidents; (v) programs for the management and/or elimination of PCBs, where applicable; (vi) vegetation management programs; (vii) training and communicating of environmental policies to employees to ensure work is conducted in an environmentally responsible manner; (viii) review of work practices that affect the environment; (ix) waste management programs; (x) environmental emergency response procedures; (xi) environmental site assessments; and (xii) environmental incident reporting procedures. Additionally, in the case of Newfoundland Power and FortisBC Electric, the EMSs also address water control and dam structure, as well as hydroelectric generating facility operations and the impact of such on fish and the surrounding habitat.

The FortisBC Energy companies, Central Hudson, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and FortisOntario have developed their respective EMSs consistent with the guidelines of ISO 14001, an internationally recognized standard for EMSs. Caribbean Utilities operates an EMS associated with its generation operations, which is ISO 14001 certified, and uses an EMS for its T&D operations, which is consistent with ISO 14001 guidelines. Fortis Turks and Caicos' EMS, when fully implemented, is also expected to be ISO 14001 certified. As part of their respective EMS, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor performance. External and/or internal audits of the EMSs are performed on a periodic basis. Based on audits last completed, the EMSs continue to be effective, properly implemented and maintained, and materially consistent with ISO 14001 guidelines.

Each of the Corporation's Canadian Regulated Electric Utilities that is a member of the CEA is an active participant in the CEA's Sustainable Electricity Program, which was launched in 2009. Participants in the program commit to continuous improvement of their environmental management and performance including reporting annually on environmental and other performance indicators.

In addition to the EMSs, various energy efficiency programs and initiatives, which help in reducing GHG emissions, are undertaken by the utilities or offered to customers.

Environmental risks associated with the Corporation's non-regulated generation operations are addressed in a similar manner as the Corporation's regulated electric utilities that operate in the same jurisdiction as the non-regulated generation operations.

The key environmental risks affecting the Corporation's hospitality and real estate operations include, but are not limited to: (i) asbestos and urea-formaldehyde contamination in buildings; (ii) release of ozone-depleting substances from air conditioning and refrigeration equipment; (iii) fuel tank leaks; and (iv) remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. Fortis Properties is committed to meeting the requirements of environmental standards related to its hospitality and real estate operations. In assessing properties being acquired, all must meet environmental standards, including, but not limited to, the appropriate federal, provincial and municipal standards for asbestos, fuel storage, urea-formaldehyde and chlorofluorocarbon-based refrigerants in air conditioning and refrigeration equipment. This process is also applied to existing properties, ensuring environmental compliance by all facilities.

The Corporation has asset-retirement obligations as disclosed in the notes to its 2013 Audited Consolidated Financial Statements. With the exception of a total of approximately $3 million at FortisBC Electric and Central Hudson, liabilities with respect to asset-retirement obligations have not been recorded in the Corporation's 2013 Audited Consolidated Financial Statements, as they could not be reasonably estimated or were determined to be immaterial (including asset-retirement obligations associated with asbestos and chemically treated poles) to the Corporation's consolidated results of operations, cash flows or financial position. The utilities have ongoing programs to identify and replace transformers which are at risk of spillage of oil, and PCBs continue to be removed from service and safely disposed of in compliance with applicable laws and regulations.

Costs associated with environmental protection initiatives (including the development, implementation and maintenance of EMSs), compliance with environmental laws, regulations and guidelines, and environmental damage did not materially affect the Corporation's consolidated results of operations, cash flows or financial position during 2013 and, based on current laws, facts and circumstances, are not expected to have a material effect in 2014. Many of the above costs, however, are embedded in the utilities' operating, maintenance and capital programs and are, therefore, not readily identifiable. At the Corporation's regulated utilities, prudently incurred operating and capital costs associated with environmental protection initiatives, compliance with environmental laws, regulations and guidelines, and environmental damage are eligible for recovery in customer rates. Fortis believes that the Corporation and its subsidiaries are materially compliant with the environmental laws and regulations applicable to them in the various jurisdictions in which they operate.

Oversight of environmental matters is performed at the subsidiary level with regular reporting of environmental matters to the respective subsidiary's Board of Directors.

For further information on the Corporation's environmental risk factors, refer to the "Business Risk Management - Environmental Risks" section of the Corporation's MD&A.

6.0 RISK FACTORS

For information with respect to the Corporation's business risks, refer to the "Business Risk Management" section of the Corporation's MD&A.

7.0 GENERAL DESCRIPTION OF SHARE CAPITAL STRUCTURE

The authorized share capital of the Corporation consists of the following:

(a) an unlimited number of Common Shares without nominal or par value;
(b) an unlimited number of First Preference Shares without nominal or par value; and
(c) an unlimited number of Second Preference Shares without nominal or par value.

As at March 13, 2014, the following Common Shares and First Preference Shares were issued and outstanding.

Share Capital	Issued and Outstanding	Votes per Share [1]
Common Shares	214,120,742	One
First Preference Shares, Series E	7,993,500	None
First Preference Shares, Series F	5,000,000	None
First Preference Shares, Series G	9,200,000	None
First Preference Shares, Series H	10,000,000	None
First Preference Shares, Series J	8,000,000	None
First Preference Shares, Series K	10,000,000	None

[1] *The First Preference Shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive, and whether such dividends have been declared.*

Convertible Debentures Represented by Installment Receipts

To finance a portion of the pending acquisition of UNS Energy, in January 2014 Fortis, through a direct wholly owned subsidiary, completed the sale of $1.8 billion aggregate principal amount of 4% convertible unsecured subordinated debentures, represented by Installment Receipts.

The debentures were sold on an installment basis at a price of $1,000 per debenture, of which $333 was paid on closing and the remaining $667 is payable on a date to be fixed following satisfaction of all conditions precedent to the closing of the acquisition. Prior to the final installment date, the debentures are represented by Installment Receipts. The Installment Receipts began trading on the TSX on January 9, 2014 under the symbol "FTS.IR". The debentures will not be listed. The debentures will mature on January 9, 2024 and bear interest at an annual rate of 4% per $1,000 principal amount of debentures until and including the final installment date, after which the interest rate will be 0%.

At the option of the investors and provided that payment of the final installment has been made, each debenture will be convertible into Common Shares of Fortis at any time after the final installment date but prior to maturity or redemption by the Corporation at a conversion price of $30.72 per common share, being a conversion rate of 32.5521 Common Shares per $1,000 principal amount of debentures.

For additional information with respect to the debentures, refer to the "Significant Items – Convertible Debentures Represented by Installment Receipts" section of the Corporation's MD&A.

Dividend Policy

The following table summarizes the cash dividends declared per share for each of the Corporation's class of shares for the past three years.

	Dividends Declared *(per share)*		
Share Capital	**2013**	**2012**	**2011**
Common Shares	**$1.25**	$1.21	$1.17
First Preference Shares, Series C (1)	**$0.4862**	$1.3625	$1.3625
First Preference Shares, Series E	**$1.2250**	$1.2250	$1.2250
First Preference Shares, Series F	**$1.2250**	$1.2250	$1.2250
First Preference Shares, Series G (2)	**$1.1416**	$1.3125	$1.3125
First Preference Shares, Series H	**$1.0625**	$1.0625	$1.0625
First Preference Shares, Series J (3)	**$1.1875**	$0.3514	-
First Preference Shares, Series K (4)	**$0.6233**	-	-

(1) *In July 2013 the Corporation redeemed all the issued and outstanding First Preference Shares, Series C at a redemption price of $25.1456 per share, being equal to $25.00 plus the amount of accrued and unpaid dividends per share.*

(2) *The annual fixed dividend per share for the First Preference Shares, Series G was reset from $1.3125 to $0.9708 for the five-year period from and including September 1, 2013 to but excluding September 1, 2018.*

(3) *The First Preference Shares, Series J were issued in November 2012 at $25.00 per share and are entitled to receive cumulative dividends in the amount of $1.1875 per share annum.*

(4) *The Fixed Rate Reset First Preference Shares, Series K were issued in July 2013 at $25.00 per share and are entitled to receive cumulative dividends in the amount of $1.0000 per share per annum for the first six years.*

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on Common and Preferred Shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

On December 9, 2013, the Board declared an increase in the quarterly Common Share dividend to $0.32 per share from $0.31 per share, with the first payment made on March 1, 2014, to holders of record as of February 14, 2014. Also on December 9, 2013, the Board declared a first quarter 2014 dividend on the First Preference Shares, Series E, F, G, H, J and K in accordance with the applicable annual prescribed rate and was paid on March 1, 2014 to holders of record as of February 14, 2014.

On March 13, 2014, the Board declared a second quarter 2014 dividend of $0.32 per Common Share and a second quarter 2014 dividend on the First Preference Shares, Series E, F, G, H, J and K in accordance with the applicable annual prescribed rate. In each case, the second quarter 2014 dividends will be paid on June 1, 2014 to holders of record as of May 16, 2014.

Common Shares

Dividends on Common Shares are declared at the discretion of the Board. Holders of Common Shares are entitled to dividends on a pro rata basis if, as, and when declared by the Board. Subject to the rights of the holders of the First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive dividends in priority to or rateably with the holders of the Common Shares, the Board may declare dividends on the Common Shares to the exclusion of any other class of shares of the Corporation.

On the liquidation, dissolution or winding-up of Fortis, holders of Common Shares are entitled to participate rateably in any distribution of assets of Fortis, subject to the rights of holders of First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or rateably with the holders of the Common Shares.

Holders of the Common Shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Fortis, other than separate meetings of holders of any other class or series of shares, and are entitled to one vote in respect of each Common Share held at such meetings.

First Preference Shares, Series C

In July 2013 the Corporation redeemed all of the 5,000,000 issued and outstanding 5.45% First Preference Shares, Series C at a redemption price of $25.1456 per share, being equal to $25.00 plus the amount of accrued and unpaid dividends per share.

First Preference Shares, Series E

Holders of the 7,993,500 First Preference Shares, Series E are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. The Corporation may, at its option, redeem all, or from time to time any part of, the outstanding First Preference Shares, Series E by the payment in cash of a sum per redeemed share equal to $25.75 if redeemed during the 12 months commencing June 1, 2013; $25.50 if redeemed during the 12 months commencing June 1, 2014; $25.25 if redeemed during the 12 months commencing June 1, 2015; and $25.00 if redeemed on or after June 1, 2016 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. The Corporation may, at its option, convert all, or from time to time any part of the outstanding First Preference Shares, Series E into fully paid and freely tradeable Common Shares of the Corporation.

The number of Common Shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per First Preference Share, Series E, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares at such time. On or after September 1, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first business day of September, December, March and June of each year, into fully paid and freely tradeable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares. If a holder of First Preference Shares, Series E elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference, Shares E for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series F

Holders of the 5,000,000 First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. The Corporation may, at its option, redeem for cash the First Preference Shares, Series F, in whole at any time or in part from time to time, at $25.50 per share if redeemed on or after December 1, 2013 but before December 1, 2014; at $25.25 per share if redeemed on or after December 1, 2014 but before December 1, 2015; and at $25.00 per share if redeemed on or after December 1, 2015 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series G

Holders of the 9,200,000 First Preference Shares, Series G were entitled to receive fixed cumulative preferential cash dividends at a rate of $1.3125 per share per annum for each year up to and including August 31, 2013. The annual fixed dividend rate per share for the First Preference Shares, Series G was reset to $0.9708 per share per annum for the five-year period from and including September 1, 2013 to but excluding September 1, 2018. For each five-year period after that date, the holders of First Preference Shares, Series G are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13%. On September 1, 2018, and on September 1 every five years thereafter, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series G, in whole at any time, or in part from time to time, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series H

Holders of the 10,000,000 First Preference Shares, Series H are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.0625 per share per annum for each year up to but excluding June 1, 2015. For each five-year period after that date, the holders of First Preference Shares, Series H are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 1.45%.

On each Series H Conversion Date, being June 1, 2015, and June 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series H, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series H Conversion Date, the holders of First Preference Shares, Series H, have the option to convert any or all of their First Preference Shares, Series H into an equal number of cumulative redeemable floating rate First Preference Shares, Series I.

Holders of the First Preference Shares, Series I will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada Treasury Bills plus 1.45%.

On each First Preference Shares, Series I Conversion Date, being June 1, 2020, and June 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On any date after June 1, 2015, that is not a First Preference Shares, Series I Conversion Date, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each First Preference Shares, Series I Conversion Date, the holders of First Preference Shares, Series I have the option to convert any or all of their First Preference Shares, Series I into an equal number of First Preference Shares, Series H.

On any First Preference Shares, Series H Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series H outstanding, such remaining First Preference Shares, Series H will automatically be converted into an equal number of First Preference Shares, Series I. On any First Preference Shares, Series I Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series I outstanding, such remaining First Preference Shares, Series I will automatically be converted into an equal number of First Preference Shares, Series H. However, if such automatic conversions would result in less than 1,000,000 First Preference Shares, Series I or less than 1,000,000 First Preference Shares, Series H outstanding then no automatic conversion would take place.

First Preference Shares, Series J

Holders of the 8,000,000 First Preference Shares, Series J are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.1875 per share per annum. On or after December 1, 2017, the Corporation may, at its option, redeem for cash the First Preference Shares, Series J, in whole at any time or in part from time to time, at $26.00 per share if redeemed before December 1, 2018; at $25.75 per share if redeemed on or after December 1, 2018 but before December 1, 2019; at $25.50 per share if redeemed on or after December 1, 2019 but before December 1, 2020; at $25.25 per share if redeemed on or after December 1, 2020 but before December 1, 2021; and at $25.00 per share if redeemed on or after December 1, 2021 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series K

Holders of the 10,000,000 First Preference Shares, Series K are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.0000 per share per annum for each year up to but excluding March 1, 2019. For each five-year period after that date, the holders of First Preference Shares, Series K are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.05%.

On each Series K Conversion Date, being March 1, 2019, and March 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series K, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series K Conversion Date, the holders of First Preference Shares, Series K have the option to convert any or all of their First Preference Shares, Series K into an equal number of cumulative redeemable floating rate First Preference Shares, Series L.

Holders of the First Preference Shares, Series L will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada Treasury Bills plus 2.05%.

On each First Preference Shares, Series L Conversion Date, being March 1, 2024, and March 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series L at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On any date after March 1, 2019, that is not a First Preference Shares, Series L Conversion Date, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series L at a price of $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each First Preference Shares, Series L Conversion Date, the holders of First Preference Shares, Series L have the option to convert any or all of their First Preference Shares, Series L into an equal number of First Preference Shares, Series K.

On any First Preference Shares, Series K Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series K outstanding, such remaining First Preference Shares, Series K will automatically be converted into an equal number of First Preference Shares, Series L. On any First Preference Shares, Series L Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series L outstanding, such remaining First Preference Shares, Series L will automatically be converted into an equal number of First Preference Shares, Series K. However, if such automatic conversions would result in less than 1,000,000 First Preference Shares, Series L or less than 1,000,000 First Preference Shares, Series K outstanding then no automatic conversion would take place.

Debt Covenant Restrictions on Dividend Distributions

The Trust Indenture pertaining to the Corporation's $200 million Senior Unsecured Debentures contains a covenant which provides that Fortis shall not declare or pay any dividends (other than stock dividends or cumulative preferred dividends on preferred shares not issued as stock dividends) or make any other distribution on its shares or redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

The Corporation has a $1 billion unsecured committed revolving corporate credit facility, maturing in July 2018, that is available for interim financing of acquisitions and for general corporate purposes. The credit facility contains a covenant which provides that Fortis shall not declare or pay any dividends or make any other restricted payments if, immediately thereafter, consolidated debt to consolidated capitalization ratio would exceed 70% at any time.

As at December 31, 2013 and 2012, the Corporation was in compliance with its debt covenant restrictions pertaining to dividend distributions, as described above.

8.0 CREDIT RATINGS

Securities issued by Fortis and its utilities, that are currently rated, are rated by one or more credit rating agencies, namely, DBRS, S&P and/or Moody's. The ratings assigned to securities issued by Fortis and its utilities are reviewed by the agencies on an ongoing basis. Credit ratings and stability ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are not recommendations to buy, sell or hold securities. Ratings may be subject to revision or withdrawal at any time by the rating organization. The following table summarizes the Corporation's credit ratings as at March 13, 2014.

Fortis Credit Ratings

Company	DBRS	S&P	Moody's
Fortis	A (low), under review with developing implications (unsecured debt)	A-, negative (unsecured debt)	N/A
FHI	BBB (high), stable (unsecured debt)	N/A	Baa2, negative (unsecured debt)
FEI	A, stable (secured & unsecured debt)	N/A	A3, negative (unsecured debt)
FEVI	N/A	N/A	A3, negative (unsecured debt)
Central Hudson [(1)]	N/A	A, stable (unsecured debt)	A2, stable (unsecured debt)
FortisAlberta	A (low), positive (senior unsecured debt)	A-, negative (senior unsecured debt)	N/A
FortisBC Electric	A (low), stable (secured & unsecured debt)	N/A	Baa1, negative (unsecured debt)
Newfoundland Power	A, stable (first mortgage bonds)	N/A	A2, stable (first mortgage bonds)
Maritime Electric	N/A	A, negative (senior secured debt)	N/A
Caribbean Utilities	A (low), stable (senior unsecured debt)	A-, negative (senior unsecured debt)	N/A

(1) *Central Hudson's senior unsecured debt is also rated by Fitch Ratings at 'A, stable'.*

DBRS rates debt instruments by rating categories ranging from AAA to D, which represents the range from highest to lowest quality of such securities. DBRS states that: (i) 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; (ii) its 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; and (iii) every rating is based on quantitative and qualitative considerations that are relevant for the borrowing entity. According to DBRS, a rating of A by DBRS is in the middle of three subcategories within the third highest of nine major categories. Such rating is assigned to debt instruments considered to be of satisfactory credit quality and for which protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. Entities rated in the BBB category are considered to have long-term debt 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. The assignment of a (high) or (low) modifier within each rating category indicates relative standing within such category.

S&P long-term debt ratings are on a ratings scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities. S&P uses '+' or '-' designations to indicate the relative standing of securities within a particular rating category. S&P states that its credit ratings are current opinions of the financial security characteristics with respect to the ability to pay under contracts in accordance with their terms. This opinion is not specific to any particular contract, nor does it address the suitability of a particular contract for a specific purpose or purchaser. An issuer rated A is regarded as having financial security characteristics to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than those in higher-rated categories.

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 states that its long-term debt ratings are opinions of relative risk of fixed-income obligations with an original maturity of one year or more and that 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 and such a debt rating is assigned to debt instruments considered to be of medium-grade quality. Debt instruments rated Baa are subject to moderate credit risk and may possess certain speculative characteristics. Debt instruments rated A are considered upper-medium grade and are subject to low credit risk.

9.0 MARKET FOR SECURITIES

The Common Shares; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series J; and First Preference Shares, Series K of Fortis are listed on the TSX under the symbols FTS, FTS.PR.E, FTS.PR.F, FTS.PR.G, FTS.PR.H, FTS.PR.J and FTS.PR.K, respectively. The First Preference Shares, Series C and Subscription Receipts of Fortis were previously listed on the TSX under the symbols FTS.PR.C and FTS.R, respectively. Beginning in January 2014, the Installment Receipts of Fortis began trading on the TSX under the symbol FTS.IR.

The following table sets forth the reported high and low trading prices and trading volumes for the Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series J; First Preference Shares, Series K; and Subscription Receipts on a monthly basis for the year ended December 31, 2013.

Fortis 2013 Trading Prices and Volumes						
	Common Shares			**First Preference Shares, Series C** [1]		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	34.85	33.92	7,028,930	25.80	25.50	37,516
February	34.89	32.89	8,565,427	25.68	25.14	371,329
March	34.29	33.21	9,213,786	25.34	25.15	176,447
April	35.08	33.06	9,634,522	25.50	25.22	263,259
May	35.14	33.00	11,446,339	25.46	25.07	191,089
June	33.32	30.70	13,177,638	25.16	25.10	30,776
July	32.95	31.25	8,084,459	25.24	25.12	4,956
August	32.45	29.92	8,815,840	-	-	-
September	31.57	29.78	13,894,725	-	-	-
October	32.80	30.76	9,216,065	-	-	-
November	32.84	31.00	9,871,013	-	-	-
December	31.68	29.51	11,521,039	-	-	-

[1] *The First Preference Shares, Series C were redeemed in July 2013.*

Fortis
2013 Trading Prices and Volumes

	First Preference Shares, Series E			First Preference Shares, Series F		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	27.19	26.64	38,132	26.05	25.80	63,277
February	27.03	26.30	61,519	26.25	25.74	372,278
March	26.64	26.18	161,461	26.02	25.79	68,561
April	26.83	26.27	62,483	26.17	25.65	49,615
May	26.54	26.08	151,923	26.06	25.08	133,510
June	26.27	25.95	17,127	25.12	22.89	109,880
July	26.16	25.90	25,989	24.76	23.28	93,996
August	26.15	25.15	102,324	23.64	21.51	160,433
September	26.04	25.80	277,950	24.12	21.67	268,832
October	26.16	25.90	142,029	24.77	22.87	110,290
November	26.22	25.83	110,659	24.05	23.25	83,563
December	26.25	25.62	144,603	23.51	21.66	235,877
	First Preference Shares, Series G			**First Preference Shares, Series H**		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	25.10	24.32	619,282	26.03	25.43	236,790
February	25.31	24.87	462,897	26.25	25.45	232,420
March	25.38	24.99	231,399	26.38	25.80	293,989
April	25.39	25.09	166,680	26.26	25.29	166,015
May	25.78	25.01	223,188	25.92	25.10	142,715
June	25.12	22.33	141,639	25.46	24.05	169,198
July	24.92	24.03	172,482	24.62	22.53	186,298
August	24.05	22.90	152,750	22.98	19.90	266,107
September	23.82	23.20	186,736	22.17	20.68	254,009
October	24.10	23.35	210,044	22.30	20.12	329,107
November	24.19	23.78	166,399	22.38	20.80	447,312
December	24.13	23.76	235,211	21.55	21.00	587,546
	First Preference Shares, Series J			**First Preference Shares, Series K** [1]		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	26.09	25.54	455,909	-	-	-
February	26.27	25.56	296,524	-	-	-
March	26.12	25.60	307,650	-	-	-
April	26.26	25.85	271,529	-	-	-
May	26.10	25.52	166,192	-	-	-
June	25.60	22.31	206,705	-	-	-
July	24.49	22.75	193,041	25.29	24.90	619,484
August	23.58	20.99	239,500	25.25	24.25	216,119
September	23.75	21.13	378,127	24.84	24.10	158,746
October	23.75	22.33	215,801	24.76	24.20	329,716
November	23.59	22.37	252,735	24.78	23.96	137,442
December	22.70	21.24	378,358	24.84	24.05	194,721

	Subscription Receipts [2]		
Month	**High ($)**	**Low ($)**	**Volume**
January	35.02	33.94	1,182,323
February	35.10	32.25	451,480
March	34.87	33.89	868,842
April	35.31	33.64	331,471
May	35.40	33.25	1,076,259
June	34.47	31.89	1,557,411

(1) *The First Preference Shares, Series K were issued in July 2013.*
(2) *The Subscription Receipts were converted into Common Shares in June 2013.*

10.0 DIRECTORS AND OFFICERS

The Board has governance guidelines which cover various items, including director tenure. The governance guidelines provide that Directors of the Corporation are to be elected for a term of one year and, except in appropriate circumstances determined by the Board, be eligible for re-election until the Annual Meeting of Shareholders next following the date on which they achieve age 70 or the 12th anniversary of their initial election to the Board. The policy does not apply to Mr. Marshall, whose service on the Board is related to his tenure as CEO. The following chart sets out the name and municipality of residence of each of the Directors of Fortis and indicates their principal occupations within five preceding years.

Fortis Directors	
Name	**Principal Occupations Within Five Preceding Years**
PETER E. CASE *(1) (2)* Kingston, Ontario	Mr. Case, 59, a Corporate Director, retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. During his 17-year career as senior investment analyst with CIBC World Markets and BMO Nesbitt Burns and its predecessors, Mr. Case's coverage of Canadian and selected U.S. pipeline and energy utilities was consistently rated among the top rankings. Mr. Case was awarded a Bachelor of Arts and an MBA from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto. He was first elected to the Board in May 2005 and has been Chair of the Audit Committee of the Board since March 2011. Mr. Case was a Director of FortisOntario from 2003 through 2010 and served as Chair of the FortisOntario Board from 2009 through 2010. He does not serve as a director of any other reporting issuer.
FRANK J. CROTHERS *(2)* Nassau, Bahamas	Mr. Crothers, 69, is Chairman and Chief Executive Officer of Island Corporate Holdings Limited, Nassau, Bahamas, a private Bahamas-based investment company with diverse interests throughout the Caribbean, North America, Australia and South Africa. For more than 35 years, he has served on many public and private sector boards. For over a decade he was on the Board of Harvard University Graduate School of Education and also served a three-year term as Chairman of CARILEC, the Caribbean Association of Electrical Utilities. Mr. Crothers is the past President of FortisTCI, which was acquired by the Corporation in August 2006. He serves on the Board of Caribbean Utilities. Mr. Crothers was first elected to the Fortis Board in May 2007. He was previously a director of Belize Electricity from 2007 to 2010. Mr. Crothers is also a director of reporting issuers AML Limited and Templeton Mutual Funds.
IDA J. GOODREAU *(3)* Vancouver, British Columbia	Ms. Goodreau, 62, is an Adjunct Professor at Sauder School of Business, University of British Columbia. She is a past President and Chief Executive Officer of LifeLabs. Prior to joining LifeLabs in March 2009, she served as President and Chief Executive Officer of Vancouver Coastal Health Authority from 2002. Ms. Goodreau has held senior leadership roles in several Canadian and international pulp and paper and natural gas companies. She was awarded an MBA and a Bachelor of Commerce, Honours, degree from the University of Windsor and a Bachelor of Arts (English and Economics) from the University of Western Ontario. Ms. Goodreau was first elected to the Board in May 2009. She has served on numerous private and public sector boards and has been a director of FHI and FortisBC Inc. since 2007 and 2010, respectively. Ms. Goodreau does not serve as a director of any other reporting issuer.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
DOUGLAS J. HAUGHEY *(1) (3)* Calgary, Alberta	Mr. Haughey, 57, from August 2012 through May 2013, was Chief Executive Officer of The Churchill Corporation, a commercial construction and industrial services company focused on the western Canadian market. From 2010 through its successful sale to Pembina Pipeline in April 2012, he served as President and Chief Executive Officer of Provident Energy Ltd., an owner/operator of natural gas liquids midstream facilities. From 1999 through 2008, he held several executive roles with Spectra Energy and predecessor companies. Mr. Haughey had overall responsibility for its western Canadian natural gas midstream business, was President and Chief Executive Officer of Spectra Energy Income Fund and also led Spectra's strategic development and mergers and acquisitions teams based in Houston, Texas. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with an MBA. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors. He was first elected to the Board in May 2009. Mr. Haughey became a director of FortisAlberta in 2010, and serves as Chair of that Board. Mr. Haughey is also a director of Keyera Corporation.
H. STANLEY MARSHALL Paradise, Newfoundland and Labrador	Mr. Marshall, 63, is President and Chief Executive Officer of the Corporation. He joined Newfoundland Power in 1979 and was appointed President and Chief Executive Officer of Fortis in 1996. Mr. Marshall graduated from the University of Waterloo with a Bachelor of Applied Science (Chemical Engineering) and from Dalhousie University with a Bachelor of Laws. He is a member of the Law Society of Newfoundland and Labrador and a Registered Professional Engineer in the Province of Newfoundland and Labrador. Mr. Marshall was first elected to the Board in October 1995. He serves as a Director of Fortis utility subsidiaries in British Columbia, Ontario, New York and the Caribbean, as well as Fortis Properties. Mr. Marshall is also a director of Enerflex Ltd.
JOHN S. McCALLUM *(1) (2)* Winnipeg, Manitoba	Mr. McCallum, 70, has been a Professor of Finance at the University of Manitoba since July 1973. He served as Chairman of Manitoba Hydro from 1991 to 2000 and as Policy Advisor to the Federal Minister of Finance from 1984 to 1991. Mr. McCallum graduated from the University of Montreal with a Bachelor of Arts (Economics) and a Bachelor of Science (Mathematics). He was awarded an MBA from Queen's University and a PhD in Finance from the University of Toronto. Mr. McCallum was first elected to the Board in July 2001 and was appointed Chair of the Governance and Nominating Committee of the Board in May 2005. He was previously a Director of FortisBC Inc. and FortisAlberta from 2004 through 2010 and from 2005 through 2010, respectively. Mr. McCallum also serves as a director of IGM Financial Inc. and Toromont Industries Ltd.
HARRY McWATTERS *(2)* Summerland, British Columbia	Mr. McWatters, 68, is President of Vintage Consulting Group Inc., Harry McWatters Inc., and TIME Estate Winery, all of which are engaged in various aspects of the British Columbia wine industry. He is the founder and past President of Sumac Ridge Estate Wine Group. Mr. McWatters was first elected to the Board in May 2007. He was a Director of FHI and FortisBC Inc., where he served as Chair from 2006 through 2010. Mr. McWatters does not serve as a director of any other reporting issuer.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
RONALD D. MUNKLEY *(2) (3)* Mississauga, Ontario	Mr. Munkley, 68, a Corporate Director, retired in April 2009 as Vice Chairman and Head of the Power and Utility Business of CIBC World Markets. Mr. Munkley had acted as an advisor on most Canadian utility transactions since joining CIBC World Markets in 1998. Prior to that, he was employed at Enbridge Consumers Gas for 27 years, culminating in his role as Chairman, President and Chief Executive Officer. Mr. Munkley led Enbridge Consumers Gas through its deregulation and restructuring in the 1990s. He graduated from Queen's University with a Bachelor of Science (Engineering), Honours. Mr. Munkley is a professional engineer and has completed the Executive and Senior Executive Programs of the University of Western Ontario and the Partners, Directors and Senior Officers Certificate of the Canadian Securities Institute. He was first elected to the Board in May 2009. Mr. Munkley also serves as a director of Bird Construction Inc.
DAVID G. NORRIS *(1) (2) (3)* St. John's, Newfoundland and Labrador	Mr. Norris, 66, a Corporate Director, was a financial and management consultant from 2001 until his retirement in December 2013. Prior to that he was Executive Vice President, Finance and Business Development of Fishery Products International Limited. Previously, he held Deputy Minister positions with the Department of Finance and Treasury Board of the Government of Newfoundland and Labrador. Mr. Norris graduated with a Bachelor of Commerce, Honours, from Memorial University of Newfoundland and an MBA from McMaster University. He was first elected to the Board in May 2005 and was appointed Chair of the Board in December 2010. Mr. Norris served as Chair of the Audit Committee of the Board from May 2006 through March 2011. He was a director of Newfoundland Power from 2003 through 2010 and served as Chair of that Board from 2006 through 2010. Mr. Norris served as a director of Fortis Properties from 2006 through 2010. He does not serve as a director of any other reporting issuer.
MICHAEL A. PAVEY *(1) (3)* Moncton, New Brunswick	Mr. Pavey, 66, a Corporate Director, retired as Executive Vice President and Chief Financial Officer of Major Drilling Group International Inc. in September 2006. Prior to joining Major Drilling Group International Inc. in 1999, he held senior executive positions, including Senior Vice President and Chief Financial Officer of TransAlta Corporation. Mr. Pavey graduated from University of Waterloo with a Bachelor of Applied Science (Mechanical Engineering) and from McGill University with an MBA. He served as a Director of Maritime Electric from 2001 through 2007 and was Chair of that Company's Audit and Environment Committee from 2003 through 2007. Mr. Pavey was first elected to the Board in May 2004 and was appointed Chair of the Human Resources Committee in May 2013. He does not serve as a director of any other reporting issuer.

(1) *Serves on the Audit Committee*
(2) *Serves on the Governance and Nominating Committee*
(3) *Serves on the Human Resources Committee*

The following table sets out the name and municipality of residence of each of the officers of Fortis and indicates the office held.

Fortis Officers	
Name and Municipality of Residence	**Office Held**
H. Stanley Marshall Paradise, Newfoundland and Labrador	President and Chief Executive Officer (1)
Barry V. Perry Mount Pearl, Newfoundland and Labrador	Vice President, Finance and Chief Financial Officer (2)
Ronald W. McCabe St. John's, Newfoundland and Labrador	Vice President, General Counsel and Corporate Secretary (3)
James D. Spinney Mount Pearl, Newfoundland and Labrador	Treasurer (4)
Jamie D. Roberts Mount Pearl, Newfoundland and Labrador	Controller (5)
Donna G. Hynes St. John's, Newfoundland and Labrador	Assistant Secretary (6)

(1) *Mr. Marshall was appointed President and Chief Operating Officer, effective October 1, 1995. Effective May 1, 1996, Mr. Marshall became Chief Executive Officer.*
(2) *Mr. Perry was appointed Vice President, Finance and Chief Financial Officer, effective January 1, 2004. Prior to that time, Mr. Perry was Vice President, Finance and Chief Financial Officer of Newfoundland Power.*
(3) *Mr. McCabe was appointed General Counsel and Corporate Secretary, effective January 1, 1997. Effective May 6, 2008, Mr. McCabe became Vice President, General Counsel and Corporate Secretary.*
(4) *Mr. Spinney was appointed Treasurer, effective March 20, 2013. Prior to that time, Mr. Spinney was Manager, Treasury at Fortis since October 2002.*
(5) *Mr. Roberts was appointed Controller, effective March 20, 2013. Prior to that time, Mr. Roberts was Vice President, Finance and Chief Financial Officer of Fortis Properties since July 2008.*
(6) *Ms. Hynes was appointed Assistant Secretary, effective December 8, 1999. She joined Fortis as Manager, Investor and Public Relations in October 1999 and, prior to that time, was employed by Newfoundland Power.*

As at December 31, 2013, the directors and officers of Fortis, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 819,243 Common Shares, representing 0.4% of the issued and outstanding Common Shares of Fortis. The Common Shares are the only voting securities of the Corporation.

11.0 AUDIT COMMITTEE

11.1 Education and Experience

The education and experience of each Audit Committee Member that is relevant to such Member's responsibilities as a Member of the Audit Committee are set out below. As at December 31, 2013, the Audit Committee was composed of the following persons.

Fortis Audit Committee	
Name	**Relevant Education and Experience**
PETER E. CASE *(Chair)* Kingston, Ontario	Mr. Case retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. He was awarded a Bachelor of Arts and an MBA from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto.
DOUGLAS J. HAUGHEY Calgary, Alberta	Mr. Haughey, from August 2012 through May 2013, was Chief Executive Officer of The Churchill Corporation. Prior to that, he served as President and Chief Executive Officer of Provident Energy Ltd. and held several executive roles with Spectra Energy and predecessor companies. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with an MBA. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors.
JOHN S. McCALLUM Winnipeg, Manitoba	Mr. McCallum is a Professor of Finance at the University of Manitoba. He graduated from the University of Montreal with a Bachelor of Arts (Economics) and a Bachelor of Science (Mathematics). Mr. McCallum was awarded an MBA from Queen's University and a PhD in Finance from the University of Toronto.
DAVID G. NORRIS St. John's, Newfoundland and Labrador	Mr. Norris was a financial and management consultant from 2001 until his retirement in December 2013. Prior to that he was Executive Vice President, Finance and Business Development of Fishery Products International Limited. He graduated with a Bachelor of Commerce, Honours, from Memorial University of Newfoundland and an MBA from McMaster University.
MICHAEL A. PAVEY Moncton, New Brunswick	Mr. Pavey retired as Executive Vice President and Chief Financial Officer of Major Drilling Group International Inc. in September 2006. Prior to joining Major Drilling Group International Inc. in 1999, he held senior executive positions, including Senior Vice President and Chief Financial Officer of TransAlta Corporation. Mr. Pavey graduated from University of Waterloo with a Bachelor of Applied Science (Mechanical Engineering) and from McGill University with an MBA.

The Board has determined that each of the Audit Committee Members is independent and financially literate. Independent means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110 - *Audit Committees*. Financially literate means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be raised by the Corporation's consolidated financial statements.

11.2 Audit Committee Mandate

The text of the Corporation's Audit Committee Mandate is detailed below.

A. Objective

The Committee shall provide assistance to the Board by overseeing the external audit of the Corporation's annual financial statements and the accounting and financial reporting and disclosure processes and policies of the Corporation.

B. Definitions

In this mandate:

"AIF" means the Annual Information Form filed by the Corporation;

"Committee" means the Audit Committee appointed by the Board pursuant to this mandate;

"Board" means the board of directors of the Corporation;

"Corporation" means Fortis Inc.;

"Director" means a member of the Board;

"Financially Literate" means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be present in the Corporation's financial statements;

"External Auditor" means the firm of chartered accountants, registered with the Canadian Public Accountability Board or its successor, and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

"Independent" means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110;

"Internal Auditor" means the person employed or engaged by the Corporation to perform the internal audit function of the Corporation;

"Management" means the senior officers of the Corporation;

"MD&A" means the Corporation's management discussion and analysis prepared in accordance with National Instrument 51-102F1 in respect of the Corporation's annual and interim financial statements; and

"Member" means a Director appointed to the Committee.

C. Composition and Meetings

1. The Committee shall be appointed annually by the Board and shall be comprised of three (3) or more Directors, each of whom is Independent and Financially Literate and none of whom is a member of Management or an employee of the Corporation or of any affiliate of the Corporation.

2. The Board shall appoint a Chair of the Committee on the recommendation of the Corporation's Governance and Nominating Committee, or such other committee as the Board may authorize.

3. The Committee shall meet at least four (4) times each year and shall meet at such other times during the year as it deems appropriate. Meetings of the Committee shall be held at the call (i) of the Chair of the Committee, or (ii) of any two (2) Members, or (iii) of the External Auditor.

4. The President and Chief Executive Officer, the Vice President, Finance and Chief Financial Officer, the External Auditor and the Internal Auditor, shall receive notice of, and (unless otherwise determined by the Chair of the Committee) shall attend all meetings of the Committee.

5. A quorum at any meeting of the Committee shall be three (3) Members.

6. The Chair of the Committee shall act as chair of all meetings of the Committee at which the Chair is present. In the absence of the Chair from any meeting of the Committee, the Members present at the meeting shall appoint one of their Members to act as Chair of the meeting.

7. Unless otherwise determined by the Chair of the Committee, the Secretary of the Corporation shall act as secretary of all meetings of the Committee.

D. Oversight of the External Audit and the Accounting and Financial Reporting and Disclosure Processes and Policies

The primary purpose of the Committee is oversight of the Corporation's external audit and the accounting and financial reporting and disclosure processes and policies on behalf of the Board. Management of the Corporation is responsible for the selection, implementation and maintenance of appropriate accounting and financial reporting principles and policies and internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations. Management is responsible for the preparation and integrity of the financial statements of the Corporation.

1. Oversight of the External Audit

   The oversight of the external audit pertains to the audit of the Corporation's annual financial statements.

   1.1. The Committee is responsible for the evaluation and recommendation of the External Auditor to be proposed by the Board for appointment by the shareholders.

   1.2. In advance of each audit, the Committee shall review the External Auditor's audit plan including the general approach, scope and areas subject to risk of material misstatement.

   1.3. The Committee is responsible for approving the terms of engagement and fees of the External Auditor.

1.4. The Committee shall review and discuss the Corporation's annual audited financial statements, together with the External Auditor's report thereon, and MD&A with Management and the External Auditor to gain reasonable assurance as to the accuracy, consistency and completeness thereof. The Committee shall meet privately with the External Auditor. The Committee shall oversee the work of the External Auditor and resolve any disagreements between Management and the External Auditor.

1.5. The Committee shall use reasonable efforts, including discussion with the External Auditor, to satisfy itself as to the External Auditor's independence as defined in Canadian Auditing Standard – 260.

2. Oversight of the Accounting and Financial Reporting and Disclosure Processes

2.1. The Committee shall recommend the annual audited financial statements together with the MD&A for approval by the Board.

2.2. The Committee shall review the interim unaudited financial statements with the External Auditor and Management, together with the External Auditor's review engagement report thereon.

2.3. The Committee shall review and approve publication of the interim unaudited financial statements together with notes thereto, the interim MD&A and earnings media release on behalf of the Board.

2.4. The Committee shall review and recommend approval by the Board of the Corporation's AIF, Management Information Circular, any prospectus and other financial information or disclosure documents to be issued by the Corporation prior to their public release.

2.5. The Committee shall use reasonable efforts to satisfy itself as to the integrity of the Corporation's financial information systems, internal control over financial reporting and the competence of the Corporation's accounting personnel and senior financial management responsible for accounting and financial reporting.

2.6. The Committee shall use reasonable efforts to satisfy itself as to the appropriateness of the Corporation's material financing and tax structures.

2.7. The Committee shall be responsible for the oversight of the Internal Auditor.

2.8. The Committee shall monitor and report on the development of the Enterprise Risk Management Program.

3. Oversight of the Audit Committee Mandate and Policies

On a periodic basis, the Committee shall review and report to the Board on the Audit Committee Mandate as well as on the following policies:

3.1. Reporting Allegations of Suspected Improper Conduct and Wrongdoing Policy;

3.2. Derivative Financial Instruments and Hedging Policy;

3.3. Pre-Approval of Audit and Non-Audit Services Policy;

3.4. Hiring of Employees from Independent Auditing Firms Policy;

3.5. The Internal Audit Role and Function Policy; and

3.6. Any other policies that may be established, from time to time, relating to accounting and financial reporting and disclosure processes; oversight of the external audit of the Corporation's financial statements; and oversight of the internal audit function.

E. Reporting

The Chair of the Committee, or another designated Member, shall report to the Board at each regular meeting on those matters which were dealt with by the Committee since the last regular meeting of the Board.

F. Other

1. The Committee shall perform such other functions as may, from time to time, be assigned to the Committee by the Board.

2. The Committee may approve, in circumstances that it considers appropriate, the engagement by the Committee or any Director of outside advisors or persons having special expertise at the expense of the Corporation.

11.3 Pre-Approval Policies and Procedures

The Audit Committee has established a policy which requires pre-approval of all audit and non-audit services provided to the Corporation and its subsidiaries by the Corporation's External Auditor. The Pre-Approval of Audit and Non-Audit Services Policy describes the services which may be contracted from the External Auditor and the limitations and authorization procedures related thereto. This policy defines services such as bookkeeping, valuations, internal audit and management functions which may not be contracted from the External Auditor and establishes an annual limit for permissible non-audit services not greater than the total fee for audit services. Audit Committee pre-approval is required for all audit and non-audit services.

11.4 External Auditor Service Fees

Fees incurred by the Corporation for work performed by Ernst & Young LLP, the Corporation's External Auditors, during each of the last two fiscal years for audit, audit-related, tax, and non-audit services were as follows.

Fortis
External Auditor Service Fees
($ thousands)

Ernst & Young LLP	**2013**	2012
Audit Fees	**3,190**	2,484
Audit-Related Fees	**673**	806
Tax Fees	**221**	139
Non-Audit Services	**-**	138
Total	**4,084**	3,567

Audit fees were higher in 2013 mainly due to work performed by Ernst & Young LLP related to CH Energy Group's annual audit and quarterly reviews since acquisition in June 2013. The increase in tax fees was related to a capital asset review at Fortis Properties in 2013. Ernst & Young LLP did not provide any non-audit services in 2013.

12.0 TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares, First Preference Shares and Installment Receipts of Fortis is Computershare Trust Company of Canada in Halifax, Montréal and Toronto.

Computershare Trust Company of Canada
9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.investorcentre.com/fortisinc

13.0 AUDITORS

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants, The Fortis Building, 7th Floor, 139 Water Street, St. John's, NL, A1C 1B2. The consolidated financial statements of the Corporation for the fiscal year ended December 31, 2013 have been audited by Ernst & Young LLP. Ernst & Young LLP report that they are independent of the Corporation in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Newfoundland.

14.0 ADDITIONAL INFORMATION

Reference is made to the MD&A and 2013 Audited Consolidated Financial Statements on pages 6 through 73 and pages 74 through 137, respectively, of the 2013 Fortis Inc. Annual Report to Shareholders, which pages are incorporated herein by reference. Additional information relating to the Corporation can be found on SEDAR at www.sedar.com.

Further additional information, including officers' and directors' remuneration and indebtedness, principal holders of the securities of Fortis, options to purchase securities and interests of insiders in material transactions, where applicable, will be contained in the Management Information Circular of Fortis to be dated on or about March 27, 2014 for the May 14, 2014 Annual Meeting of Shareholders. Additional financial information is also provided in the 2013 Audited Consolidated Financial Statements and the MD&A.

Requests for additional copies of the above-mentioned documents, as well as the 2013 Annual Information Form, should be directed to the Corporate Secretary, Fortis, P.O. Box 8837, St. John's, NL, A1B 3T2 (telephone: 709.737.2800). In addition, such documentation and additional information relating to the Corporation is contained on the Corporation's website at www.fortisinc.com.

FORTIS INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2014

February 18, 2015

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2014

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DEFINITIONS OF CERTAIN TERMS

Certain terms used in this 2014 Annual Information Form are defined below:

"2014 Annual Information Form" means this annual information form of the Corporation in respect of the year ended December 31, 2014;

"2014 Audited Consolidated Financial Statements" means the audited consolidated financial statements of the Corporation as at and for the years ended December 31, 2014 and 2013 and related notes thereto;

"ACC" means the Arizona Corporation Commission;

"Algoma Power" means Algoma Power Inc.;

"AUC" means the Alberta Utilities Commission;

"BC Hydro" means the BC Hydro and Power Authority;

"BCUC" means the British Columbia Utilities Commission;

"BECOL" means Belize Electric Company Limited;

"Belize Electricity" means Belize Electricity Limited;

"BEPC" means Brilliant Expansion Power Corporation;

"Board" means the Board of Directors of the Corporation;

"BPC" means Brilliant Power Corporation;

"Canadian Niagara Power" means Canadian Niagara Power Inc.;

"Caribbean Utilities" means Caribbean Utilities Company, Ltd.;

"CEA" means the Canadian Electricity Association;

"Central Hudson" means Central Hudson Gas & Electric Corporation;

"CEO" means the Chief Executive Officer of the Corporation;

"CH Energy Group" means CH Energy Group, Inc.;

"Convertible Debentures" means the $1.8 billion aggregate principal amount of 4% convertible unsecured subordinated debentures represented by Installment Receipts issued by the Corporation in January 2014;

"COPE" means the Canadian Office and Professional Employees Union;

"Cornwall Electric" means Cornwall Street Railway, Light and Power Company, Limited;

"Corporation" means Fortis Inc.;

"CPA" means the Canal Plant Agreement;

"CPC/CBT" means Columbia Power Corporation and Columbia Basin Trust;

"CUPE" means the Canadian Union of Public Employees;

"DBRS" means DBRS Limited;

"DEC" means the New York State Department of Environmental Conservation;

“Eastern Canadian Electric Utilities” means, collectively, the operations of Newfoundland Power, Maritime Electric and FortisOntario;

“EMS” means environmental management systems;

“EPA” means the United States Environmental Protection Agency;

“ERA” means the Electricity Regulatory Authority of the Cayman Islands;

“External Auditor” means the firm of Chartered Professional Accountants registered with the Canadian Public Accountability Board or its successor and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

“FAES” means FortisBC Alternative Energy Services Inc.;

“FEI” means FortisBC Energy Inc.;

“FERC” means the United States Federal Energy Regulatory Commission;

“FEVI” means FortisBC Energy (Vancouver Island) Inc.;

“FEWI” means FortisBC Energy (Whistler) Inc.;

“FHI” means FortisBC Holdings Inc., the parent company of FEI, FEVI and FEWI;

“Final Installment Date” means the date on which the second and final installment payment in respect of the Convertible Debentures was paid, being October 27, 2014;

“Fitch” means Fitch Ratings Inc.;

“Fortis” means Fortis Inc.;

“FortisAlberta” means FortisAlberta Inc.;

“FortisAlberta Holdings” means FortisAlberta Holdings Inc.;

“FortisBC Amalgamation” means the amalgamation of FEI, FEVI, FEWI and one or more non-operating companies, effective December 31, 2014;

“FortisBC Electric” means, collectively, the operations of FortisBC Inc. and its parent company, FortisBC Pacific Holdings Inc., but excludes its wholly owned partnership, Walden Power Partnership;

“FortisBC Energy companies” means FortisBC Energy Inc., the company resulting from the FortisBC Amalgamation;

“FortisBC Pacific Holdings” means FortisBC Pacific Holdings Inc.;

“Fortis Generation East Partnership” means Fortis Generation East LLP;

“FortisOntario” means, collectively, the operations of Canadian Niagara Power, Cornwall Electric and Algoma Power;

“Fortis Properties” means Fortis Properties Corporation;

“FortisTCI” means FortisTCI Limited;

“Fortis Turks and Caicos” means, collectively, FortisTCI and Turks and Caicos Utilities Limited;

“FortisUS” means FortisUS Inc.;

“FortisUS Energy” means FortisUS Energy Corporation;

“FortisUS Holdings” means FortisUS Holdings Nova Scotia Limited;

"FortisWest" means FortisWest Inc.;

"**Four Corners"** means Four Corners Generating Station;

"GHG" means greenhouse gas;

"GOB" means the Government of Belize;

"Griffith" means Griffith Energy Services, Inc.;

"GSMIP" means Gas Supply Mitigation Incentive Plan;

"GWh" means gigawatt hour(s);

"Hydro One" means Hydro One Networks Inc.;

"IBEW" means the International Brotherhood of Electrical Workers;

"IESO" means the Independent Electricity System Operator of Ontario;

"Installment Receipts" means the installment receipts representing the Convertible Debentures;

"ISO" means International Organization for Standardization;

"LNG" means liquefied natural gas;

"Management" means, collectively, the senior officers of the Corporation;

"Maritime Electric" means Maritime Electric Company, Limited;

"MD&A" means the Corporation's Management Discussion and Analysis prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations,* in respect of the Corporation's annual consolidated financial statements for the year ended December 31, 2014;

"MGP" means manufactured gas plant;

"Moody's" means Moody's Investors Service;

"MW" means megawatt(s);

"MWh" means megawatt hour(s);

"NB Power" means New Brunswick Power Corporation;

"NEB" means the National Energy Board;

"Newfoundland Hydro" means Newfoundland and Labrador Hydro Corporation;

"Newfoundland Power" means Newfoundland Power Inc.;

"NYISO" means the New York Independent System Operator;

"OEB" means the Ontario Energy Board;

"PBR" means performance-based rate-setting;

"PCB" means polychlorinated biphenyl;

"PEI" means Prince Edward Island;

"PEI Energy Accord" means the Prince Edward Island Energy Accord;

“PJ” means petajoule(s);

“Point Lepreau” means the NB Power Point Lepreau Nuclear Generating Station;

“PPA” means power purchase agreement;

“PPFAC” means purchased power and fuel adjustment clause;

“PRMP” means Price Risk Management Plan;

“PSC” means the New York State Public Service Commission;

“PUB” means the Newfoundland and Labrador Board of Commissioners of Public Utilities;

“ROE” means rate of return on common shareholders’ equity;

“S&P” means Standard & Poor’s Ratings Services;

“SEDAR” means the System for Electronic Document Analysis and Retrieval;

“SJCC” means San Juan Coal Company;

“SJGS” means San Juan Generating Station;

“Spectra Energy” means Westcoast Energy Inc. doing business as Spectra Energy Transmission;

“T&D” means transmission and distribution;

“Teck Metals” means Teck Metals Ltd.;

“TEP” means Tucson Electric Power Company;

“TJ” means terajoule(s);

“TransCanada” means TransCanada Pipelines Limited;

“TSX” means the Toronto Stock Exchange;

“UFCW” means the United Food and Commercial Workers;

“UNS Electric” means UNS Electric, Inc.;

“UNS Energy” means collectively, the operations of TEP, UNS Electric and UNS Gas;

“UNS Gas” means UNS Gas, Inc.;

“US GAAP” means accounting principles generally accepted in the United States;

“USW” means the United Steel Workers;

“UUWA” means the United Utility Workers’ Association of Canada;

“Walden” means the Walden Power Partnership;

“Waneta Expansion” means the 335-MW hydroelectric generating facility being constructed adjacent to the existing Waneta Plant on the Pend d’Oreille River in British Columbia;

“Waneta Partnership” means the Waneta Expansion Limited Partnership between CPC/CBT and Fortis;

“WECA” means the Waneta Expansion Capacity Agreement; and

“Whistler” means the Resort Municipality of Whistler.

1.0 CORPORATE STRUCTURE

The 2014 Annual Information Form has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. Financial information has been prepared in accordance with US GAAP and is presented in Canadian dollars unless otherwise specified.

Except as otherwise stated, the information in the 2014 Annual Information Form is given as of December 31, 2014.

Fortis includes forward-looking information in the 2014 Annual Information Form within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide Management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. 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 2014 Annual Information Form, including the 2014 MD&A incorporated herein by reference, includes, but is not limited to, statements regarding: the Corporation's review of strategic options for its hotel and commercial real estate business; that the principal business of Fortis will remain the ownership and operation of regulated electric and gas utilities; the Corporation's primary focus on Canada and the United States in the acquisition of regulated utilities; the expected capital investment in Canada's electricity sector over the 20-year period through 2030 to maintain system reliability; the expectation that UNS Energy will be able to satisfy the requirements of its customer base and meet future peak demand requirements; the expectation that there will be a significant reduction in the use of coal in certain of UNS Energy's generating facilities by 2020; forecast 2015 to 2019 midyear rate bases for the Corporation's largest regulated utilities; the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the Corporations consolidated forecast gross capital expenditures for 2015 and total capital spending over the five-year period from 2015 through 2019; UNS Energy's forecast capital program for 2015 through 2018; the expectation that UNS Electric will be successful in acquiring solar generating capacity in Mohave County, Arizona; various natural gas investment opportunities that may be available to the Corporation; the nature, timing and expected costs of certain capital projects including, without limitation, the Waneta Expansion, the Tilbury liquefied natural gas facility expansion, the Woodfibre pipeline expansion, the development of a diesel power plant in Grand Cayman, and the Pinal transmission project in Arizona; the expectation that the Corporation's significant capital expenditure program will support continuing growth in earnings and dividends; the assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed; the expectation that the Corporation's regulated utilities could experience disruptions and increased costs if they are unable to maintain their asset base; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long-term debt offerings; the expectation that the Corporation's subsidiaries will be able to source the cash required to fund their 2015 capital expenditure programs, operating and interest costs, and dividend payments; the expected consolidated long-term debt maturities and repayments in 2015 and on average annually over the next five years; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to capital in the near to long term; the expectation that the combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2015; the intent of Management to hedge future exchange rate fluctuations and monitor its foreign currency exposure; the impact of advances in technology and new energy efficiency standards on the Corporation's results of operations; the impact of new or revised environmental laws and regulations on the Corporation's results of operations; the expectation that any liability from current legal proceedings will not have a material adverse effect on the Corporation's consolidated financial position and results of operations; the belief that the Corporation has a strong, well-positioned case supporting the unconstitutionality of the expropriation of the Corporation's investment in Belize; and the expectation that the adoption of future accounting pronouncements will not have a material impact on the Corporation's 2014 Audited Consolidated Financial Statements.

The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: a favourable outlook for the potential sale of assets or shares in the hotel and commercial real estate market; the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received, and the expectation of regulatory stability; FortisAlberta's continued recovery of its cost of service and ability to earn its allowed ROE under performance-based rate-setting, which commenced for a five-year term effective January 1, 2013; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the electricity and gas systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; no material capital project and financing cost overrun related to the construction of the non-regulated Waneta Expansion; sufficient liquidity and capital resources; the expectation that the Corporation will receive appropriate compensation from the GOB for fair value of the Corporation's investment in Belize Electricity that was expropriated by the GOB; the expectation that BECOL will not be expropriated by the GOB; the continuation of regulator-approved mechanisms to flow through the cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices, electricity prices and fuel prices; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans and environmental laws that may materially negatively affect the operations and cash flows of the Corporation and its subsidiaries; no material change in public policies and directions by governments that could materially negatively affect the Corporation and its subsidiaries; new or revised environmental laws and regulations will not severely affect the results of operations; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under US GAAP beyond 2018 or the adoption of International Financial Reporting Standards after 2018 that allows for the recognition of regulatory assets and liabilities; the continued tax-deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology infrastructure; continued favourable relations with First Nations; favourable labour relations; that the Corporation can reasonably accurately assess the merit of and potential liability attributable to ongoing legal proceedings; and sufficient human resources to deliver service and execute the capital program.

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. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risk Management" in the MD&A for the year ended December 31, 2014 and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. Key risk factors for 2015 include, but are not limited to: uncertainty of the impact a continuation of a low interest rate environment may have on the allowed ROE at the Corporation's regulated utilities; uncertainty regarding the treatment of certain capital expenditures at FortisAlberta under the newly implemented PBR mechanism; risk associated with the amount of compensation to be paid to Fortis for its investment in Belize Electricity that was expropriated by the GOB; and the timeliness of the receipt of the compensation and the ability of the GOB to pay the compensation owing to Fortis.

All forward-looking information in the 2014 Annual Information Form is qualified in its entirety by the above cautionary statements 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.

1.1 Name and Incorporation

Fortis is a holding company that was incorporated as 81800 Canada Ltd. under the *Canada Business Corporations Act* on June 28, 1977 and continued under the *Corporations Act* (Newfoundland and Labrador) on August 28, 1987.

The articles of incorporation of the Corporation were amended to: (i) change its name to Fortis on October 13, 1987; (ii) set out the rights, privileges, restrictions and conditions attached to the Common Shares on October 15, 1987; (iii) designate 2,000,000 First Preference Shares, Series A on September 11, 1990; (iv) replace the class rights, privileges, restrictions and conditions attaching to the First Preference Shares and the Second Preference Shares on July 22, 1991; (v) designate 2,000,000 First Preference Shares, Series B on December 13, 1995; (vi) designate 5,000,000 First Preference Shares, Series C on May 27, 2003; (vii) designate 8,000,000 First Preference Shares, Series D and First Preference Shares, Series E on January 23, 2004; (viii) amend the redemption provisions attaching to the First Preference Shares, Series D on July 15, 2005; (ix) designate 5,000,000 First Preference Shares, Series F on September 22, 2006; (x) designate 9,200,000 First Preference Shares, Series G on May 20, 2008; (xi) designate 10,000,000 First Preference Shares, Series H and 10,000,000 First Preference Shares, Series I on January 20, 2010; (xii) designate 8,000,000 First Preference Shares, Series J on November 8, 2012; (xiii) designate 12,000,000 First Preference Shares, Series K and 12,000,000 First Preference Shares, Series L on July 11, 2013; and (xiv) designate 24,000,000 First Preference Shares, Series M and 24,000,000 First Preference Shares, Series N on September 16,2014.

Fortis redeemed all of its outstanding First Preference Shares, Series A, First Preference Shares, Series B and First Preference Shares, Series C on September 30, 1997, December 2, 2002, and July 10 2013, respectively. On January 29, 2004, Fortis issued 8,000,000 First Preference Units, each unit consisting of one First Preference Share, Series D and one Warrant. During 2004, 7,993,500 First Preference Units were converted into 7,993,500 First Preference Shares, Series E and 6,500 First Preference Shares, Series D remained outstanding. On September 20, 2005, the 6,500 First Preference Shares, Series D were redeemed by the Corporation. On September 28, 2006, Fortis issued 5,000,000 First Preference Shares, Series F. On May 23, 2008, Fortis issued 8,000,000 First Preference Shares, Series G and on June 4, 2008 issued an additional 1,200,000 First Preference Shares, Series G, following the exercise of an over-allotment option in connection with the offering of the 8,000,000 First Preference Shares, Series G. On January 26, 2010, Fortis issued 10,000,000 First Preference Shares, Series H. On November 13, 2012, Fortis issued 8,000,000 First Preference Shares, Series J. On July 18, 2013, Fortis issued 10,000,000 First Preference Shares, Series K. On September 19, 2014, Fortis issued 24,000,000 First Preference Shares, Series M.

The corporate head office of Fortis is located at Fortis Place, Suite 1100, 5 Springdale Street, P.O. Box 8837, St. John's, NL, Canada, A1B 3T2. The registered office of Fortis is located at the Fortis Building, Suite 1201, 139 Water Street, P.O. Box 8837, St. John's, NL, Canada, A1B 3T2.

1.2 Inter-Corporate Relationships

Fortis is a leader in the North American electric and gas utility business, with total assets of more than $26 billion and fiscal 2014 revenue of $5.4 billion. Its regulated utilities account for approximately 93% of total assets and serve more than 3 million customers across Canada and in the United States and the Caribbean. Fortis owns non-regulated hydroelectric generation assets in Canada, Belize and upstate New York. The Corporation's non-utility investment is comprised of hotels and commercial real estate in Canada.

The following table lists the principal subsidiaries of the Corporation, their jurisdictions of incorporation and the percentage of votes attaching to voting securities held directly or indirectly by the Corporation as at February 18, 2015. This table excludes certain subsidiaries, the total assets of which individually constituted less than 10% of the Corporation's consolidated assets as at December 31, 2014, or the total revenue of which individually constituted less than 10% of the Corporation's 2014 consolidated revenue. Additionally, the principal subsidiaries together comprise approximately 86% of the Corporation's consolidated assets as at December 31, 2014 and approximately 82% of the Corporation's 2014 consolidated revenue.

Principal Subsidiaries		
Subsidiary	**Jurisdiction of Incorporation**	**Percentage of votes attaching to voting securities beneficially owned, controlled or directed by the Corporation**
UNS Energy [1]	Arizona State, United States	100
Central Hudson [2]	New York State, United States	100
FHI	British Columbia, Canada	100
FortisAlberta [3]	Alberta, Canada	100
FortisBC Inc. [4]	British Columbia, Canada	100
Newfoundland Power	Newfoundland and Labrador, Canada	95[5]

(1) *UNS Energy, an Arizona State corporation, owns all of the shares of TEP, UNS Electric and UNS Gas. FortisUS, a Delaware State corporation, owns all of the shares of UNS Energy. FortisUS Holdings, a Canadian corporation, owns all of the shares of FortisUS. Fortis owns all of the shares of FortisUS Holdings.*

(2) *CH Energy Group, a New York State corporation, owns all of the shares of Central Hudson. FortisUS, a Delaware State corporation, owns all of the shares of CH Energy Group. FortisUS Holdings, a Canadian corporation, owns all of the shares of FortisUS. Fortis owns all of the shares of FortisUS Holdings.*

(3) *FortisAlberta Holdings, an Alberta corporation, owns all of the shares of FortisAlberta. FortisWest, a Canadian corporation, owns all of the shares of FortisAlberta Holdings. Fortis owns all of the shares of FortisWest.*

(4) *FortisBC Pacific Holdings, a British Columbia corporation, owns all of the shares of FortisBC Inc. FortisWest, a Canadian corporation, owns all of the shares of FortisBC Pacific Holdings. Fortis owns all of the shares of FortisWest.*

(5) *Fortis owns all of the common shares and certain of the First Preference Shares, Series A, B, D and G of Newfoundland Power which, as at February 18, 2015, represent 95% of its voting securities. The remaining 5% of Newfoundland Power's voting securities consist of First Preference Shares, Series A, B, D and G, which are primarily held by the public.*

2.0 GENERAL DEVELOPMENT OF THE BUSINESS

2.1 Three-Year History

Over the past three years, Fortis has experienced significant growth in its business operations. Total assets have grown 87% from approximately $14.2 billion as at December 31, 2011 to approximately $26.6 billion as at December 31, 2014. The Corporation's shareholders' equity has also grown 86% from approximately $4.9 billion as at December 31, 2011 to approximately $9.1 billion as at December 31, 2014. Net earnings attributable to common equity shareholders have increased from $311 million in 2011 to $317 million in 2014. Earnings in 2014, however, were reduced by non-recurring items, largely associated with the acquisition of UNS Energy.

The growth in business operations reflects the Corporation's profitable growth strategy for its principal regulated electric and gas utility businesses. This strategy includes a combination of growth from acquisitions and organic growth through the Corporation's consolidated capital expenditure program.

Over the past three years, Fortis has significantly increased its regulated utility investments through acquisitions. In August 2014 Fortis acquired UNS Energy for a purchase price of approximately US$4.5 billion, including the assumption of approximately US$2.0 billion of debt on closing. UNS Energy is a vertically integrated utility services holding company, headquartered in Tucson, Arizona, engaged through its primary subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona, serving approximately 658,000 electricity and gas customers. In June 2013 Fortis acquired CH Energy Group for a purchase price of approximately US$1.5 billion, including the assumption of US$518 million of debt on closing. CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson, is a regulated T&D utility serving approximately 300,000 electric customers and 77,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. In March 2013 FortisBC Electric acquired the electric utility assets of the City of Kelowna for approximately $55 million, which allows FortisBC Electric to directly serve some 15,000 customers formerly served by the City. FortisBC Electric had provided the City with electricity under a wholesale tariff and had operated and maintained the City's electric utility assets under contract since 2000.

The Corporation's gross consolidated capital expenditures for 2014 were approximately $1.7 billion, up almost 50% from 2013. Over the past three years, gross consolidated capital expenditures were $4 billion. Organic asset growth at the regulated utilities has been driven by the capital expenditure programs in western Canada. Total assets at FortisAlberta and the FortisBC gas and electric utilities have grown by approximately 29% and 6%, respectively, over the past three years. Organic growth at non-regulated operations has been driven by approximately $679 million in total that has been spent on the Waneta Expansion since construction began in late 2010.

2.2 Outlook

Fortis is a leader in the North American electric and gas utility business, currently serving more than 3 million customers. The Corporation's focus continues to be on low risk, regulated utility businesses and long-term contracted energy infrastructure.

In September 2014 the Corporation announced that it would engage in a review of strategic options for its hotel and commercial real estate business, operating as Fortis Properties. Strategic options may include, but are not limited to, a sale of all or a portion of the assets, a sale of shares of Fortis Properties or an initial public offering. A decision on this review is expected to be made in the second quarter of 2015. Fortis Properties currently comprises approximately 3% of the Corporation's total assets.

Following a decade of significant growth, mainly resulting from acquisitions, Fortis is entering a period of significant growth from its existing operations. The Corporation's consolidated capital program is expected to exceed $2 billion for 2015. Over the five-year period through 2019, it is expected to approach $9 billion.

Over the next five years, total investment in energy infrastructure is expected to increase midyear rate base by approximately 36% from $14 billion in 2014 to approximately $19 billion in 2019. This capital investment should allow rate base to increase at a five-year compound annual growth rate of approximately 6.5% through 2019. Fortis expects that this investment will support continuing growth in earnings and dividends.

Fortis is also pursuing significant natural gas investment opportunities, particularly in British Columbia. Two new regulated projects – a further expansion of the Tilbury LNG facility and the Woodfibre pipeline expansion – could increase the five-year compound annual growth rate through 2019 to approximately 7.5%.

The approximate breakdown of the capital spending expected to be incurred over the five-year period from 2015 to 2019 is as follows: 38% at Canadian Regulated Electric Utilities, driven by FortisAlberta; 35% at Regulated Gas & Electric Utilities in the United States, driven by UNS Energy; 20% at Canadian Regulated Gas Utilities; 5% at Caribbean Regulated Electric Utilities and the remaining 2% at non-regulated operations. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, the approximate breakdown of the total capital spending to be incurred is as follows: 28% to meet customer growth; 49% to ensure continued and enhanced performance, reliability and safety of generation and T&D assets; and 23% for facilities, equipment, vehicles, information technology and other assets.

Gross consolidated capital expenditures for 2015 are expected to be approximately $2.2 billion, as summarized in the following table. Planned capital expenditures are based on detailed forecasts of energy demand, weather, cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from forecasts.

Forecast Gross Consolidated Capital Expenditures [(1)] **Year Ending December 31, 2015**	
	($ millions)
UNS Energy [(2)]	684
Central Hudson [(2)]	165
FortisBC Energy companies	385
FortisAlberta	417
FortisBC Electric	103
Eastern Canadian Electric Utilities	159
Regulated Electric Utilities – Caribbean [(2)]	125
Non-Regulated - Fortis Generation	78
Non-Regulated - Non-Utility [(3)]	36
Total	**2,152**

(1) *Relates to forecast cash payments to acquire or construct utility capital assets, non-utility capital assets and intangible assets, as would be reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of allowance for funds used during construction.*
(2) *Forecast capital expenditures are based on a forecast exchange rate of US$1.00 = CDN$1.20.*
(3) *Includes forecast capital expenditures of approximately $33 million at FAES, which is reported in the Corporate and Other segment of the Corporation's 2014 Audited Consolidated Financial Statements.*

The most significant capital projects forecast for 2015 include:

- the continuation of the Waneta Expansion, with approximately $76 million expected to be spent in 2015;
- the Tilbury LNG facility expansion by the FortisBC Energy companies, which includes the construction of a second LNG tank and a new liquefier, scheduled to be completed by the end of 2016 at a capital cost of approximately $400 million;
- the purchase by UNS Energy of additional ownership interests in Unit 1 of the Springerville generating station for US$46 million;
- the expected purchase by UNS Energy of expiring lease interests in the Springerville coal handling facilities for US$73 million, net of expected reimbursements from third parties; and
- the Pinal Transmission Project, consisting of the construction by UNS Energy of a transmission line in Pinal County to increase UNS Energy's import capacity from Gila River Unit 3 and the Palo Verde trading hub, for US$85 million.

The FortisBC Energy companies are also pursuing additional LNG investment opportunities, including a further $450 million expansion of Tilbury and a $600 million pipeline expansion for the proposed Woodfibre LNG site in British Columbia, which are not included in the current capital expenditures forecast set out in the table above.

The Corporation’s subsidiaries expect to have reasonable access to long-term capital in 2015 to fund their capital expenditure programs.

Forecast 2015 midyear rate base for the Corporation's regulated utilities is provided in the following table.

Forecast 2015 Midyear Rate Base	
	($ billions)
UNS Energy [1]	3.8
Central Hudson [1]	1.3
FortisBC Energy companies	3.7
FortisAlberta	2.7
FortisBC Electric	1.3
Eastern Canadian Electric Utilities	1.6
Regulated Electric Utilities – Caribbean [1]	0.8
Total	**15.2**

[1] *Based on a forecast exchange rate of US$1.00 = CDN$1.20.*

3.0 DESCRIPTION OF THE BUSINESS

Fortis is principally an international electric and gas utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation and non-utility assets, which are treated as two separate segments. The Corporation's reporting segments allow Management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

The business segments of the Corporation are: (i) Regulated Electric & Gas Utilities – United States; (ii) Regulated Gas Utilities – Canadian; (iii) Regulated Electric Utilities – Canadian; (iv) Regulated Electric Utilities – Caribbean; (v) Non-Regulated – Fortis Generation; (vi) Non-Regulated – Non-Utility; and (vii) Corporate and Other.

The following sections describe the operations included in each of the Corporation's reportable segments.

3.1 Regulated Electric & Gas Utilities - United States

3.1.1 *UNS Energy*

UNS Energy is a vertically integrated utility services holding company, headquartered in Tucson, Arizona, engaged through its primary subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona, serving approximately 658,000 electricity and gas customers. UNS Energy was acquired by Fortis in August 2014.

UNS Energy is primarily comprised of three wholly owned regulated utilities: TEP, UNS Electric and UNS Gas.

TEP is a vertically integrated regulated electric utility and UNS Energy's largest operating subsidiary. TEP serves approximately 415,000 retail electric customers in a territory comprising approximately 2,991 square kilometres in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP's service area covers a population of approximately 1,000,000 people.

UNS Electric is a vertically integrated regulated electric utility that generates, transmits and distributes electricity to approximately 93,000 retail electric customers in Arizona's Mohave and Santa Cruz counties, which have a combined population of approximately 250,000.

TEP and UNS Electric currently own or lease generation resources with an aggregate capacity of 2,746 MW, including 53 MW of solar capacity. TEP has sufficient generating capacity that, together with existing PPAs and expected generation plant additions, should satisfy the requirements of its customer base and meet expected future peak demand requirements. TEP also sells wholesale electricity to other entities in the western United States.

UNS Gas is a regulated gas distribution company that serves approximately 150,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties, which have a combined population of approximately 700,000.

Market and Sales

Electricity sales were 5,646 GWh from the date of acquisition. Gas volumes were 5 PJ from the date of acquisition. Revenue from the date of acquisition was US$610 million.

The following table provides the composition of UNS Energy's 2014 revenue, electricity sales, and gas volumes by customer class.

UNS Energy [(1)] **2014 Revenue and Electricity & Gas Sales by Customer Class**			
	Revenue (%)	**GWh Sales (%)**	**PJ Volumes (%)**
Residential	36.2	31.2	53.8
Commercial	22.5	19.1	24.1
Industrial	16.9	23.9	2.1
Other [(2)]	24.4	25.8	20.0
Total	100.0	100.0	100.0

[(1)] *The information presented is for the year ended December 31, 2014. UNS Energy was acquired by Fortis in August 2014; therefore, only financial results from the date of acquisition, August 15, 2014, are reflected in the Corporation's 2014 Audited Consolidated Financial Statements.*

[(2)] *Includes electricity sales and gas volumes to other entities for resale and revenue from sources other than from the sale of electricity and gas.*

Power Supply

TEP meets the electricity supply requirements of its retail and wholesale customers with its aggregate owned and leased electrical generating capacity of 2,448 MW and its transmission and distribution system consisting of approximately 15,500 kilometres of line. Collectively, TEP's generating capacity meets all of its energy and peak capacity needs. In 2014, TEP met a peak demand of 2,891 MW. TEP is a member of a regional reserve-sharing organization and has reliability and power sharing relationships with other utilities.

At January 1, 2015, TEP owned or leased 2,448 MW of generating capacity, as set forth in the following table:

Generating Source	Unit No.	Location	Date In Service	Resource Type	Capacity MW	Operating Agent	TEP's %	Share MW
Springerville Station (1)	1	Springerville, AZ	1985	Coal	387	TEP	49.5	192
Springerville Station	2	Springerville, AZ	1990	Coal	390	TEP	100.0	390
San Juan Station	1	Farmington, NM	1976	Coal	340	PNM	50.0	170
San Juan Station	2	Farmington, NM	1973	Coal	340	PNM	50.0	170
Navajo Station	1	Page, AZ	1974	Coal	750	SRP	7.5	56
Navajo Station	2	Page, AZ	1975	Coal	750	SRP	7.5	56
Navajo Station	3	Page, AZ	1976	Coal	750	SRP	7.5	56
Four Corners Station	4	Farmington, NM	1969	Coal	785	APS	7.0	55
Four Corners Station	5	Farmington, NM	1970	Coal	785	APS	7.0	55
Gila River Power Station	3	Gila Bend, AZ	2003	Gas	550	Ethos Energy	75.0	413
Luna Generating Station	1	Deming, NM	2006	Gas	555	PNM	33.3	185
Sundt Station	1	Tucson, AZ	1958	Gas/Oil	81	TEP	100.0	81
Sundt Station	2	Tucson, AZ	1960	Gas/Oil	81	TEP	100.0	81
Sundt Station	3	Tucson, AZ	1962	Gas/Oil	104	TEP	100.0	104
Sundt Station (2)	4	Tucson, AZ	1967	Coal/Gas	120	TEP	100.0	120
Sundt International Combustion Turbines		Tucson, AZ	1972-1973	Gas/Oil	50	TEP	100.0	50
DeMoss Petrie		Tucson, AZ	1972	Gas/Oil	75	TEP	100.0	75
North Loop		Tucson, AZ	2001	Gas	94	TEP	100.0	94
Springerville Solar Station		Springerville, AZ	2002-2014	Solar	16	TEP	100.0	16
Tucson Solar Projects		Tucson, AZ	2010-2014	Solar	12	TEP	100.0	12
FT. Huachuca Project		Ft. Huachuca, AZ	2014	Solar	17	TEP	100.0	17
Total Capacity (3)								**2,448**

(1) *At December 31, 2014, TEP owned 96 MW of capacity at Springerville Unit 1 and continued to lease the remaining 291 MW capacity. In January 2015, TEP purchased 96 MW of capacity bringing the total owned capacity to 192 MW. TEP's lease of the remaining 195 MW expired in January 2015. See Note 15 to the 2014 Audited Consolidated Financial Statements.*

(2) *Sundt Station Unit 4 can be operated on either coal or natural gas. The figures in the above table reflect the nominal generating capacity assuming the unit is fuelled by coal. If the unit burns natural gas, it has a nominal capacity of 156 MW.*

(3) *Excludes 932 MW of additional resources, which consist of certain capacity purchases and interruptible retail load.*

UNS Electric meets the electricity supply requirements of its retail customers through a mix of its own generation and power purchase contracts. UNS Electric owns and operates several gas and diesel-fuelled generating plants, with a collective electrical generating capacity of 298 MW, which would now provide approximately 74% of its 402 MW 2014 peak capacity needs. UNS Electric meets the balance of its requirements through a portfolio of long-term, medium-term and short-term PPAs.

Generating Source	Unit No.	Location	Date In Service	Resource Type	Capacity MW	Operating Agent	UNS' %	Share MW
Black Mountain	1	Kingman, AZ	2011	Gas	45	UNSE	100.0	45
Black Mountain	2	Kingman, AZ	2011	Gas	45	UNSE	100.0	45
Valencia	1	Nogales, AZ	Purchased 2003	Gas/Oil	14	UNSE	100.0	14
Valencia	2	Nogales, AZ	Purchased 2003	Gas/Oil	14	UNSE	100.0	14
Valencia	3	Nogales, AZ	Purchased 2003	Gas/Oil	14	UNSE	100.0	14
Valencia	4	Nogales, AZ	Purchased 2003	Gas/Oil	21	UNSE	100.0	21
Gila River Power Station	3	Gila Bend, AZ	2003	Gas	550	Ethos Energy	25.0	137
La Senita		Kingman, AZ	2011	Solar	1	UNSE	100.0	1
Rio Rico		Rio Rico, AZ	2014	Solar	7	UNSE	100.0	7
Total Capacity								**298**

In December 2014, TEP and UNS Electric together completed the acquisition of Unit 3 of the Gila River generating station, a 550 MW gas-fired combined-cycle unit for US$219 million. Both TEP and UNS Electric rely on a portfolio of long-term, medium-term and short-term PPAs to meet customer load requirements.

Each of TEP and UNS Electric are subject to government-mandated renewable energy requirements. TEP satisfies these requirements through its 45 MW of owned photovoltaic solar generating capacity and PPAs for capacity from solar resources (145 MW), wind resources (90 MW) and a landfill gas generation plant (4 MW). UNS Electric satisfies its respective requirements through its 8 MW of owned photovoltaic solar generating capacity and PPAs for capacity from solar resources (10 MW) and wind resources (11 MW). UNS Electric also expects to spend US$5 million in 2015 on a solar facility in Mohave Country.

Gas Purchases

UNS Gas directly manages its gas supply and transportation contracts. The market price for gas varies based on the period during which gas is purchased, and is affected by weather, supply issues, the economy and other factors. UNS Gas hedges its gas supply prices by entering into fixed-price forward contracts and financial swaps from time to time, up to three years in advance, with a view to hedging at least 60% of expected monthly gas consumption with fixed prices prior to the beginning of each month.

UNS Gas purchases the majority of its gas supply from the San Juan Basin. The gas is delivered on the El Paso Natural Gas, L.L.C. and Transwestern Pipeline Company interstate pipeline systems under firm transportation agreements with combined capacity sufficient to meet the demands of UNS Gas' customers.

Legal Proceedings

UNS Energy Acquisition Proceedings
Following the announcement of the acquisition of UNS Energy on December 11, 2013, four complaints naming Fortis and other defendants were filed in the Superior Court of the State of Arizona in and for the County of Pima and one claim in the United States District Court in and for the District of Arizona, challenging the acquisition. The complaints generally allege that the directors of UNS Energy breached their fiduciary duties in connection with the acquisition and that UNS Energy, Fortis, FortisUS and Color Acquisition Sub Inc. aided and abetted that breach. In March 2014 two of the four complaints filed in the Arizona Court were dismissed by the plaintiffs and counsel for the parties in the two actions remaining in the Arizona Court executed a Memorandum of Understanding recording an agreement-in-principle on the structure of a settlement to be proposed to the Arizona Court for approval following closing of the acquisition. In April 2014 the complaint filed in the United States District Court was dismissed by the plaintiff. In December 2014 the two remaining actions were assigned to a new judge, who is expected to rule on the settlement proposed to the Arizona Court. The outcome of these lawsuits cannot be predicted with any certainty and, accordingly, no amount has been accrued in the 2014 Audited Consolidated Financial Statements.

Springerville Generating Station, Unit 1
As of January 1, 2015, TEP had a 49.5% interest in unit 1 of the Springerville generating station. Under the terms of a facility support agreement, TEP has an obligation to operate the unit for the benefit of the unit's two other owners. TEP and the other owners disagree on several key aspects of the facility support agreement, including the allocation of operating and maintenance expenses, capital improvement costs, and transmission rights. As a result, the other owners may refuse to pay all or a portion of their pro rata share of such costs and expenses.

In November 2014, the Springerville Unit 1 third-party owners filed a complaint against TEP with FERC alleging that TEP had not agreed to wheel power and energy for the third-party owners in the manner specified in the Springerville Unit 1 facility support agreement between TEP and the third-party owners and for the cost specified by the third-party owners. The third-party owners requested an order from FERC requiring such wheeling of the third-party owners' energy from their Springerville Unit 1 interests beginning on January 1, 2015 for the price specified by the third-party owners. In December 2014 TEP filed a response to the FERC action denying the allegations and requesting that FERC dismiss the complaint.

In December 2014 the third-party owners filed a complaint against TEP in the Supreme Court of the

State of New York, New York County, alleging, among other things, that TEP has: refused to comply with the third-party owners' instructions to schedule their entitlement share of power and energy; failed to comply with their instructions to specify the level of fuel and fuel handling services; failed to properly operate, maintain and make capital investments in Springerville Unit 1 during the term of the leases; not agreed to wheel power and energy in the manner required as set forth in the FERC action; and breached fiduciary duties claimed to be owed to the third-party owners. The New York action seeks declaratory judgments, injunctive relief, damages in an amount to be determined at trial, and the third-party owners' fees and expenses.

In December 2014, Wilmington Trust Company, as owner trustees and lessors under the leases of the third-party owners, sent a notice to TEP that alleges that TEP has defaulted under the third-party owners' leases. The notice states that the owner trustees, as lessors, are exercising their rights to keep the undivided interests idle and demanding that TEP pay, on January 1, 2015, liquidated damages totalling approximately US$71 million. In a letter to Wilmington Trust Company dated December 29, 2014, TEP denied the allegations in the notice. In January 2015, Wilmington Trust Company sent a second notice to TEP alleging that TEP had defaulted under the third-party owners' leases by not remediating the defaults alleged in the first notice. The second notice repeated the demand that TEP pay liquidated damages totalling approximately US$71 million. In a letter to Wilmington Trust Company, TEP denied the allegations in the second notice.

TEP cannot predict the outcome of the claims relating to Springerville Unit 1 and, due to the general and non-specific scope and nature of the injunctive relief sought for these claims, TEP cannot determine estimates of the range of loss at this time and, accordingly, no amount has been accrued in the 2014 Audited Consolidated Financial Statements. TEP intends to vigorously defend itself against the claims asserted by the third-party owners.

Environmental Contingencies

San Juan Generating Station
SJCC operates an underground coal mine in an area where certain gas producers have oil and gas leases with the federal government, the State of New Mexico and private parties. These gas producers allege that SJCC's underground coal mine interferes with their operations, reducing the amount of natural gas they can recover. SJCC compensated certain gas producers for any remaining production from wells deemed close enough to the mine to warrant plugging and abandoning them. These settlements, however, do not resolve all potential claims by gas producers in the area.

TEP owns 50% of Units 1 and 2 at SJGS, which represents approximately 20% of the total generation capacity at SJGS, and is responsible for its proportionate share of any settlements. TEP cannot reasonably estimate the impact of any future claims by these gas producers on the cost of coal at SJGS and, accordingly, no amount has been accrued in the 2014 Audited Consolidated Financial Statements.

Mine Reclamation Costs
TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which TEP has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing the San Juan, Four Corners and Navajo generating stations. TEP's share of reclamation costs at all three mines is expected to be US$49 million upon expiration of the coal supply agreements, which expire between 2017 and 2031. The reclamation liability (present value of future liability) was recorded at December 31, 2014 as US$22 million.

Amounts recorded for final reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the credit-adjusted risk-free interest rate to be used to discount future liabilities. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements' terms. TEP does not believe that recognition of its final reclamation obligations will be material to TEP in any single year because recognition will occur over the remaining terms of its coal supply agreements. TEP's PPFAC allows it to fully recover reclamation costs from retail customers and, accordingly, these costs are deferred as a regulatory asset.

Human Resources

As at December 31, 2014: (i) TEP employed 1,448 employees, of whom 691 are represented by IBEW under a collective agreement expiring in January 2016; (ii) UNS Electric employed 143 employees, of whom 110 are represented by IBEW under collective agreements expiring in June 2016 and February 2017; and (iii) UNS Gas employed 182 employees, of whom 110 are represented by IBEW under collective agreements expiring June 2015 and February 2017. UniSource Energy Services Inc., another wholly owned subsidiary of UNS Energy, employed 258 employees, of whom 246 are represented by IBEW under collective agreements expiring in May 2016, July 2016 and December 2016.

3.1.2 *Central Hudson*

Central Hudson is a regulated T&D utility serving approximately 300,000 electricity customers and 77,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. Central Hudson was acquired by Fortis as part of the acquisition of CH Energy Group in June 2013.

Central Hudson serves a territory comprising approximately 6,734 square kilometres in the Hudson Valley. Electric service is available throughout the territory, and natural gas service is provided in and about the cities of Poughkeepsie, Beacon, Newburgh, and Kingston, New York, and in certain outlying and intervening territories.

Central Hudson's electric transmission system consists of approximately 1,000 kilometres of line. Central Hudson's electric distribution system consists of approximately 11,600 kilometres of overhead lines and 2,400 trench kilometres of underground lines, as well as customer service lines and meters. Central Hudson's electricity system met a peak demand of 1,060 MW in 2014.

Central Hudson's natural gas system consists of approximately 300 kilometres of transmission pipelines and 2,000 kilometres of distribution pipelines, as well as customer service lines and meters. In 2014 Central Hudson's natural gas system met a peak day demand of 138 TJ.

Market and Sales

Electricity sales were 5,075 GWh for 2014, compared to 5,159 GWh for the full year in 2013. Gas volumes for 2014 were 23 PJ, comparable with the full year in 2013. Revenue was US$743 million for 2014, compared to US$668 million for the full year in 2013.

The following tables compare the composition of Central Hudson's 2014 and 2013 revenue, electricity sales and gas volumes by customer class.

Central Hudson [(1)]
Revenue and Electricity Sales by Customer Class

	Revenue (%)		GWh Sales (%)	
	2014	2013	**2014**	2013
Residential	**60.9**	60.9	**40.3**	40.5
Commercial	**28.0**	28.0	**37.8**	37.4
Industrial	**4.1**	4.6	**20.1**	20.4
Other	**6.2**	5.8	**0.7**	0.7
Sales for Resale	**0.8**	0.7	**1.1**	1.0
Total	**100.0**	100.0	**100.0**	100.0

[(1)] *The 2013 information presented is for the year ended December 31, 2013. Central Hudson was acquired by Fortis on June 27, 2013; therefore, only financial results from the date of acquisition are reflected in the Corporation's 2013 audited consolidated financial statements.*

Central Hudson (1) Revenue and Gas Volumes by Customer Class				
	Revenue (%)		PJ Volumes (%)	
	2014	2013	**2014**	2013
Residential	**53.5**	52.4	**27.1**	24.0
Commercial	**29.0**	27.5	**33.9**	30.2
Industrial	**4.8**	3.3	**17.2**	22.0
Other	**1.1**	4.3	**7.8**	8.5
Sales for Resale	**11.6**	12.5	**14.0**	15.3
Total	**100.0**	100.0	**100.0**	100.0

(1) *The 2013 information presented is for the year ended December 31, 2013. Central Hudson was acquired by Fortis on June 27, 2013; therefore, only financial results from the date of acquisition are reflected in the Corporation's 2013 audited consolidated financial statements.*

Power Supply

Central Hudson owns minimal generating capacity and relies on purchased capacity and energy from third-party providers to meet the demands of its full service customers.

Central Hudson is required to supply electricity to its retail electric customers. Under the terms of a settlement agreement, Central Hudson's retail customers may elect to procure electricity from third-party suppliers or may continue to rely on Central Hudson. In order to satisfy the needs of its retail customers, in late 2011 Central Hudson entered into a 10-year revenue sharing agreement with Constellation Energy Group, Inc., pursuant to which Central Hudson shares in a portion of the power sales revenue attributable to Unit No. 2 of the Nine Mile Point Nuclear Generating Station.

In 2014, Central Hudson entered into two agreements with Entergy Nuclear Power Marketing, LLC to purchase electricity on a unit contingent basis at defined prices from December 2014 through March 2015. For the month of December 31, 2014, energy supplied under these agreements cost approximately US$3 million.

These contracts meet the definition of normal purchase and sale agreements and are therefore excluded from current accounting requirements related to derivatives. In the event the above noted counterparty is unable to fulfill its commitment to deliver under the terms of the agreements, Central Hudson will obtain the supply from the NYISO market, and under Central Hudson's current ratemaking treatment, recover the full cost from customers. As such, there would be no impact on earnings.

Central Hudson relies on PPAs, its own generation capacity and the NYISO market to meet its peak load requirements.

In November 2013, Central Hudson entered into a PPA to purchase 200 MW of installed capacity from the Roseton Generating Facility from May 2014 through April 2017, with approximately US$34 million in purchase commitments remaining as at December 31, 2014.

In June 2014, Central Hudson entered into a PPA to purchase capacity from the Danskammer Generating Facility from October 2014 through August 2018, with approximately US$91 million in purchase commitments remaining as at December 31, 2014.

Costs of electric and natural gas commodity purchases are recovered from customers, without earning a profit on these costs. Rates are reset monthly based on Central Hudson's actual costs to purchase the electricity and natural gas needed to serve its full service customers.

Other Contractual Obligations

CH Energy Group is party to an investment to develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with FERC for the recovery of the cost of and return on five high-voltage transmission projects totalling US$1.7 billion, of which CH Energy Group's maximum commitment is US$182 million.

Litigation

In May 2012 CH Energy Group and Fortis entered into a proposed settlement agreement with counsel to plaintiff shareholders pertaining to several complaints, which named Fortis and other defendants, which were filed in, or transferred to, the Supreme Court of the State of New York, County of New York, relating to the acquisition of CH Energy Group by Fortis. The complaints generally alleged that the directors of CH Energy Group breached their fiduciary duties in connection with the acquisition and that CH Energy Group, Fortis, FortisUS Inc. and Cascade Acquisition Sub Inc. aided and abetted that breach. The settlement agreement was subject to court approval. In June 2014 the Supreme Court of the State of New York, County of New York issued an order and final judgment approving the settlement agreement thereby concluding the proceedings.

Prior to and after the acquisition of CH Energy Group, various asbestos lawsuits had been brought against Central Hudson. While a total of 3,348 asbestos cases have been raised, 1,170 remained pending as at December 31, 2014. Of the cases no longer pending against Central Hudson, 2,022 have been dismissed or discontinued without payment by the company, and Central Hudson has settled the remaining 156 cases. The company is presently unable to assess the validity of the remaining asbestos lawsuits; however, based on information known to Central Hudson at this time, including the company's experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in 2014 Audited Consolidated Financial Statements.

Environmental Contingencies

Former MGP Facilities
Central Hudson and its predecessors owned and operated MGPs to serve their customers' heating and lighting needs. These plants manufactured gas from coal and oil beginning in the mid-to-late 1800s with all sites ceasing operations by the 1950s. This process produced certain by-products that may pose risks to human health and the environment.

The DEC, which regulates the timing and extent of remediation of MGP sites in New York State, has notified Central Hudson that it believes the company or its predecessors at one time owned and/or operated MGPs at seven sites in Central Hudson's franchise territory. The DEC has further requested that the company investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Clean-up Agreement or Brownfield Clean-up Agreement. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2014, an obligation of US$105 million was recognized in respect of MGP remediation and, based upon cost model analysis completed in 2012, it is estimated, with a 90% confidence level, that total costs to remediate these sites over the next 30 years will not exceed US$169 million.

Central Hudson has notified its insurers and intends to seek reimbursement from insurers for remediation, where coverage exists. Further, as authorized by the PSC, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for MGP site investigation and remediation and the associated rate allowances, with carrying charges to be accrued on the deferred balances at the authorized pre-tax rate of return.

Human Resources

As at December 31, 2014, Central Hudson employed 923 employees, of whom 546 are represented by IBEW under a collective agreement expiring April 30, 2017.

3.2 Regulated Gas Utilities - Canadian

3.2.1 *FortisBC Energy companies*

On December 31, 2014, FEI amalgamated with FEVI, FEWI and one or more non-operating companies, all of which were indirectly controlled by the Corporation. The amalgamated entity continues to operate under the name "FortisBC Energy Inc." and is referred to in this 2014 Annual Information Form as the "FortisBC Energy companies". Information in this 2014 Annual Information

Form presents the results of the amalgamated company.

The FortisBC Energy companies are the largest distributor of natural gas in British Columbia, serving approximately 967,000 residential, commercial and industrial and transportation customers in more than 125 communities. Major areas served by the FortisBC Energy companies include Greater Vancouver, Fraser Valley, Thompson, Okanagan, Kootenay, North Central Interior, Vancouver Island, Sunshine Coast and Whistler regions of British Columbia.

In addition to providing T&D services to customers, the FortisBC Energy companies also obtain natural gas supplies on behalf of most residential, commercial and industrial customers.

FEI owns and operates approximately 47,500 kilometres of natural gas pipelines and met a peak day demand of 1,324 TJ in 2014.

Market and Sales

Annual natural gas sales volumes of the FortisBC Energy companies were 195 PJ in 2014, compared to 200 PJ in 2013. Revenue increased to $1,435 million in 2014 from $1,378 million in 2013.

The following table compares the composition of 2014 and 2013 revenue and natural gas volumes of the FortisBC Energy companies by customer class.

FortisBC Energy companies
Revenue and Gas Volumes by Customer Class

	Revenue (%)		**PJ Volumes (%)**	
	2014	2013	**2014**	2013
Residential	**56.2**	56.1	**36.9**	37.5
Commercial	**30.2**	29.6	**23.1**	23.5
Industrial	**2.7**	3.0	**2.1**	2.5
	89.1	88.7	**62.1**	63.5
Transportation	**6.8**	6.5	**31.8**	30.5
Other [(1)]	**4.1**	4.8	**6.1**	6.0
Total	**100.0**	100.0	**100.0**	100.0

[(1)] *Includes amounts under fixed-revenue contracts and revenue from sources other than from the sale of natural gas.*

Gas Purchase Agreements

In order to ensure supply of adequate resources to provide reliable natural gas deliveries to its customers, the FortisBC Energy companies purchase natural gas supply from counterparties, including producers, aggregators and marketers. These counterparties adhere to standards of counterparty creditworthiness and contract execution and/or management policies. The FortisBC Energy companies contract for approximately 138 PJ of baseload and seasonal supply, of which the majority is sourced in northeastern British Columbia and transported on Spectra Energy's Westcoast Pipeline T-South pipeline system. The remainder is sourced in Alberta and transported on TransCanada's pipeline transportation system.

Through the operation of regulatory deferrals, any difference between the forecast cost of natural gas purchases, as reflected in residential and commercial customer rates, and the actual cost of natural gas purchases is recovered from, or refunded to, customers in future rates.

Core market customers rely on the FortisBC Energy companies to procure and deliver gas supply on their behalf, while transportation-only customers are responsible for procuring and delivering their own gas to the FortisBC Energy companies' system, which is then delivered to their operating premises by the FortisBC Energy companies. The FortisBC Energy companies contract for transportation capacity on third-party pipelines, such as those owned by Spectra Energy and TransCanada to transport gas supply from various market hubs to the FortisBC Energy companies' system. These third party pipelines are regulated by the NEB. The FortisBC Energy companies pay both fixed and variable charges for the use of transportation capacity on these pipelines, which are recovered through rates paid by core market customers. The FortisBC Energy companies contract for firm transportation capacity in order to ensure they are able to meet their obligations to supply customers within their broad operating region under all reasonable demand scenarios.

Gas Storage and Peak-Shaving Arrangements

The FortisBC Energy companies incorporate peak shaving and gas storage facilities into their portfolio to:

(i) supplement contracted baseload and seasonal gas supply in the winter months while injecting excess baseload supply to refill storage in the summer months;
(ii) mitigate the risk of supply shortages during cooler weather and a peak day;
(iii) manage the cost of gas during winter months; and
(iv) balance daily supply and demand on the distribution system during periods of peak use that occur over the course of the winter months.

The FortisBC Energy companies hold approximately 35.5 PJs of total storage capacity consisting of two peak shaving LNG facilities and off-system capacity contracted with third parties. The FortisBC Energy companies' owned on-system Tilbury and Mt. Hayes LNG peak shaving facilities provide on-system storage capacity and deliverability associated with storage withdrawals. The FortisBC Energy companies also contract for off-system underground storage capacity and deliverability from third parties at various locations in British Columbia, Alberta and the Pacific Northwest of the United States. On a combined basis, the Tilbury and Mt. Hayes LNG facilities, the contracted storage facilities, and other peaking arrangements have the ability to deliver up to 0.74 PJ per day of supply to the FortisBC Energy companies on the coldest days of the heating season. The heating season typically occurs during the December through February period.

Off-System Sales

The FortisBC Energy companies engage in off-system sales activities that allow for the recovery or mitigation of costs of any unutilized supply and/or pipeline and storage capacity that is available once customers' daily load requirements are met.

Under the GSMIP revenue sharing model, which is approved by the BCUC, the FortisBC Energy companies can earn an incentive payment for mitigation activities. Historically, the FortisBC Energy companies have earned approximately $1 million annually through GSMIP, while the remaining savings are credited back to customers through reduced rates. Subject to the BCUC's approval, the FortisBC Energy companies are eligible for an incentive payment of approximately $1 million in respect of the gas contract year ending October 31, 2014.

The current GSMIP program was approved by the BCUC following a comprehensive review in 2011. In 2013, the BCUC approved an extension of the program until October 31, 2016.

Price Risk Management Plan

In the past, FEI has engaged in price risk management activities to limit the exposure to fluctuations in natural gas prices to ensure, to the extent possible, that natural gas commodity costs remain competitive with other energy sources. These have typically included the use of derivative instruments which were implemented pursuant to a PRMP approved by the BCUC. In July 2010, the BCUC ordered a review of FEI's PRMP hedging strategy in the context of the *Clean Energy Act* (British Columbia) and the expectation of increased domestic natural gas supply. Following a comprehensive review process, in July 2011, the BCUC directed FEI to suspend the majority of its natural gas commodity hedging activities, except for the implementation of winter Sumas/AECO basis swaps. For winter 2013 and 2014, FEI has reduced its Sumas price exposure risk by purchasing supply only at the Station 2 gas market trading hub and in Alberta. All hedges that had been in place from previously approved PRMPs, prior to the suspension of the hedging strategy, expired in 2014.

Unbundling

A Customer Choice program at the FortisBC Energy companies allows eligible commercial and residential customers a choice to buy their natural gas commodity supply from the

FortisBC Energy companies or directly from third-party marketers. The FortisBC Energy companies continue to provide the delivery service of the natural gas to all its customers.

The program has been in place since November 2004 for commercial customers and November 2007 for residential customers. For the year ended 2014, approximately 7% of eligible commercial customers and 5% of eligible residential customers participated in the program by purchasing their commodity supply from alternate providers.

Legal Proceedings

Coldwater Indian Band
In April 2013 FHI and Fortis were named as defendants in an action in the Supreme Court of British Columbia by the Coldwater Indian Band. The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Coldwater Indian Band seeks orders cancelling the right of way and claims damages for wrongful interference with the Coldwater Indian Band's use and enjoyment of reserve lands. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the 2014 Audited Consolidated Financial Statements.

City of Surrey
FEI was the plaintiff in an action before the Supreme Court of British Columbia against the City of Surrey in which FEI sought the Court's determination on the manner in which costs related to the relocation of a natural gas transmission pipeline would be shared between itself and the City of Surrey. The relocation was required due to the development and expansion of the City of Surrey's transportation infrastructure. FEI claimed that the parties had an agreement that dealt with the allocation of costs. In turn, the City of Surrey advanced counterclaims including an allegation that FEI breached the agreement and that the City of Surrey suffered damage as a result. In December 2013, the Court issued a decision which ordered FEI and the City of Surrey to share equally the cost of the pipeline relocation. The Court also decided that the City of Surrey was successful in its counterclaim that FEI breached the agreement. In December 2014, FEI and the City of Surrey reached a settlement, resolving all pending claims and relief sought.

Human Resources

As at December 31, 2014, the FortisBC Energy companies employed 1,660 employees. Approximately 70% of the employees are represented by IBEW and COPE under collective agreements. The IBEW collective agreement came into effect in mid-2012 and expires on March 31, 2015. A new agreement with IBEW has been ratified, coming into effect April 1, 2015 and expiring March 31, 2019. The COPE collective agreements expire March 31, 2015 and March 31, 2017, respectively.

3.3 Regulated Electric Utilities - Canadian

3.3.1 *FortisAlberta*

FortisAlberta is a regulated electricity distribution utility operating in Alberta. Its business is the ownership and operation of regulated electricity distribution facilities that distribute electricity, generated by other market participants, from high-voltage transmission substations to end-use customers. FortisAlberta is not involved in the generation, transmission or direct sale of electricity. FortisAlberta operates the electricity distribution system in a substantial portion of southern and central Alberta, totalling approximately 120,000 kilometres of distribution lines. Many of the company's customers are located in rural and suburban areas around and between the cities of Edmonton and Calgary. FortisAlberta's distribution network serves approximately 530,000 customers, comprising residential, commercial, farm, oil and gas and industrial consumers of electricity, and met a peak demand of 2,648 MW in 2014.

Market and Sales
FortisAlberta's annual energy deliveries increased to 17,372 GWh in 2014 from 16,934 GWh in 2013. Revenue was $518 million in 2014 compared to $475 million in 2013.

As a significant portion of FortisAlberta's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

The following table compares the composition of FortisAlberta's 2014 and 2013 revenue and energy deliveries by customer class.

FortisAlberta
Revenue and Energy Deliveries by Customer Class

	Revenue (%)		GWh Deliveries [1] (%)	
	2014	2013	**2014**	2013
Residential	**30.5**	30.8	**17.1**	17.0
Large commercial, industrial and oil field	**21.5**	21.6	**61.3**	61.3
Farms	**11.8**	12.2	**7.5**	7.6
Small commercial	**10.8**	11.0	**8.0**	7.9
Small oil field	**8.1**	8.6	**5.7**	5.8
Other [2]	**17.3**	15.8	**0.4**	0.4
Total	**100.0**	100.0	**100.0**	100.0

(1) *GWh percentages presented exclude FortisAlberta's GWh deliveries to "transmission-connected" customers. These deliveries were 7,076 GWh in 2014 and 6,919 GWh in 2013, based on interim settlement that is expected to be finalized in May 2015, and consisted primarily of energy deliveries to large-scale industrial customers directly connected to the transmission grid.*

(2) *Includes revenue from sources other than the delivery of energy, including that related to street-lighting services, rate riders, deferrals and adjustments.*

Franchise Agreements

FortisAlberta serves customers residing within various municipalities throughout its service areas through franchise agreements with the respective municipalities. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta located within their municipal boundaries. Upon the termination, or in the absence of a franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta) with the price to be as agreed between FortisAlberta and the municipality, failing which it is to be determined by the AUC. Additionally, under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric distribution system expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, *the Hydro and Electric Energy Act* provides that the AUC may determine that the municipality should pay compensation to FortisAlberta for any facilities transferred on the basis of replacement cost less depreciation. Given the historical population and economic growth of Alberta and its municipalities, FortisAlberta is affected by transactions of this type from time to time.

FortisAlberta holds franchise agreements with 140 municipalities within its service area. In 2012 FortisAlberta received approval of a new franchise agreement template from the AUC. The new template was filed with the AUC following negotiations with the Alberta Urban Municipalities Association and consultation with municipalities. The new franchise agreement template includes a 10-year term with an option that will permit the agreement to automatically renew for a further five years. To date, FortisAlberta converted 95 of the municipalities within its service area to the new franchise agreement, and intends to convert 90% of the remaining municipalities by the end of 2015.

Human Resources

As at December 31, 2014, FortisAlberta had 1,144 full-time equivalent employees. Approximately 76% of the employees of the company are members of the UUWA. In December 2013 FortisAlberta reached an agreement on a new four-year collective agreement with UUWA that expires on December 31, 2017.

3.3.2 *FortisBC Electric*

FortisBC Electric 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. FortisBC Electric serves a diverse mix of approximately 166,000 customers, of whom approximately 131,000 are served directly by FortisBC Electric in Kelowna, Oliver, Osoyoos, Trail, Castlegar, Creston and Rossland, while the remainder are served through the wholesale supply of power to municipal distributors in the communities of Summerland, Penticton, Grand Forks and Nelson, as well as to BC Hydro. In 2014, FortisBC Electric met a peak demand of 684 MW. Residential customers represent the largest customer class of the company. FortisBC Electric's T&D assets include approximately 7,200 kilometres of T&D lines and 65 substations.

FortisBC Electric also includes the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals and BC Hydro, the 149-MW Brilliant hydroelectric plant owned by CPC and CBT, the 185-MW Arrow Lakes hydroelectric plant owned by CPC and CBT through Arrow Lakes Power Corporation, and the 120-MW Brilliant hydroelectric expansion plant owned by CPC and CBT through Brilliant Expansion Power Corporation and the Waneta Partnership.

Market and Sales

FortisBC Electric has a diverse customer base composed primarily of residential, commercial, industrial and municipal wholesale, and other industrial customers. Annual electricity sales were 3,179 GWh in 2014, compared to 3,211 GWh in 2013. Revenue increased to $334 million in 2014 from $317 million in 2013.

The following table compares the composition of FortisBC Electric's 2014 and 2013 revenue and electricity sales by customer class.

FortisBC Electric
Revenue and Electricity Sales by Customer Class

	Revenue (%)		**GWh Sales (%)**	
	2014	2013	**2014**	2013
Residential	**48.4**	50.1	**41.2**	45.3
Commercial	**24.7**	23.2	**28.9**	23.7
Wholesale	**13.0**	15.5	**18.1**	21.6
Industrial	**9.0**	8.5	**11.8**	9.4
Other (1)	**4.9**	2.7	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes revenue from sources other than from the sale of electricity, including revenue of FortisBC Pacific Holdings associated with non-regulated operating, maintenance and management services.*

Generation and Power Supply

FortisBC Electric meets the electricity supply requirements of its customers through a mix of its own generation and power purchase contracts. The company owns four regulated hydroelectric generating plants on the Kootenay River with an aggregate capacity of 225 MW, which provide approximately 45% of the company's energy needs and 30% of its peak capacity needs. FortisBC Electric meets the balance of its requirements through a portfolio of long-term and short-term PPAs.

FortisBC Electric's four hydroelectric generating facilities are governed by the CPA. The CPA is a multi-party agreement that enables the five separate owners of eight major hydroelectric generating plants, with a combined capacity of approximately 1,600 MW and located in relatively close proximity to each other, to coordinate the operation and dispatch of their generating plants.

The following table lists the plants and their respective capacity and owner.

Plant	Capacity (MW)	Owners
Canal Plant	580	BC Hydro
Waneta Dam	493	Teck Metals and BC Hydro
Kootenay River System	225	FortisBC Electric
Brilliant Dam and Expansion	269	BPC and BEPC
Total	**1,567**	

BPC, BEPC, Teck Metals and FortisBC Electric are collectively defined in the CPA as the Entitlement Parties. The CPA enables BC Hydro and the Entitlement Parties to generate more power from their respective generating plants than they could if they operated independently 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. Under the CPA, BC Hydro takes into its system all power actually generated by the plants listed in the table above. In exchange for permitting BC Hydro to determine the output of these facilities, each of the Entitlement Parties is contractually entitled to a fixed annual entitlement of capacity and energy from BC Hydro, which is based on 50-year historical water flows. The Entitlement Parties receive their defined 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. However, FortisBC Electric retains rights to its original water licenses and flows in perpetuity. Should the CPA be terminated, the output of FortisBC Electric's Kootenay River system plants would, with the water and storage authorized under its existing licences and on a long-term average, be approximately the same power output as FortisBC Electric receives under the CPA. The CPA does not affect FortisBC Electric's ownership of its physical generation 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.

The majority of FortisBC Electric's remaining electricity supply is acquired through the following power purchase contracts:

i. a 149-MW long-term PPA with BPC terminating in 2056 (Brilliant PPA);
ii. a 200-MW PPA with BC Hydro terminating in 2033 (BC Hydro PPA);
iii. a capacity and energy purchase agreement with CPC, for a total of 78,500 MWh from 2013 through 2017 (Brilliant Expansion Capacity and Energy Purchase Agreement);
iv. a number of small power purchase contracts with independent power producers;
v. spot market and contracted capacity purchases; and
vi. a 40-year agreement to purchase capacity from the Waneta Expansion upon completion of construction, which is expected in the spring of 2015 (WECA).

The majority of the above purchase contracts have been accepted by the BCUC and forecast and incurred costs thereunder flow through to customers through FortisBC Electric's electricity rates. Although FortisBC Electric can currently meet the majority of its customer supply requirements from its own generation and the PPAs 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 are recovered through customer electricity rates, provided they are prudently incurred.

Brilliant PPA
Under the Brilliant PPA, FortisBC Electric has agreed to purchase from BPC, on a long-term basis: (i) the entitlement allocated to the Brilliant hydroelectric plant; and (ii) after the expiration of the CPA, the actual electrical output generated by the Brilliant hydroelectric plant. While the total entitlement is 985,000 MWh, FortisBC Electric does not purchase the approximate 60,000 MWh of regulated flow upgrade entitlement under the Brilliant PPA. However, FortisBC Electric has entered into another agreement with CPC for this energy over a five-year period, as discussed below. The Brilliant PPA uses a take-or-pay contract structure, which requires that FortisBC Electric pay for the Brilliant hydroelectric plant's entitlement, irrespective of whether FortisBC Electric actually takes it. FortisBC Electric does not foresee any circumstances under which FortisBC Electric would be required to pay for power that it does not require. During the first 30 years of the Brilliant PPA term,

FortisBC Electric pays to BPC an amount that covers the operation and maintenance costs of the Brilliant hydroelectric 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 hydroelectric plant and then-prevailing operating costs will be made to the amounts payable by FortisBC Electric. The Brilliant PPA provided FortisBC Electric with approximately 26% of its energy requirements in 2014.

BC Hydro PPA
FortisBC Electric is a party to the BC Hydro PPA, which provides FortisBC Electric 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 17% of FortisBC Electric's energy requirements in 2014. The current BC Hydro PPA, which replaced a previous PPA with BC Hydro, was approved by the BCUC in May 2014. The current PPA expires in September 2033.

Brilliant Expansion Capacity and Energy Purchase Agreement
In November 2012, FortisBC Electric entered into an agreement to purchase CPC's unused capacity and energy entitlements from 2013 to 2017. The entitlements are from the Brilliant hydroelectric plant and the Brilliant hydroelectric expansion plant, including the 60,000 MWh from the Brilliant hydroelectric plant that is not included in the Brilliant PPA. The agreement is for a total of 78,500 MWh and provided approximately 2% of FortisBC Electric's energy requirements in 2014.

Small Power Purchase Contracts
FortisBC Electric has a number of small power purchase contracts with independent power producers, which collectively provided less than 1% of FortisBC Electric's energy supply requirements in 2014. The majority of these contracts have been accepted by the BCUC.

Spot Market and Contracted Capacity Purchases
During 2014, FortisBC Electric entered into various arrangements to purchase capacity and energy from the market to meet its peak energy requirements and optimize its overall power supply portfolio. 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 FortisBC Electric 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 and contracted purchases provided approximately 9% of the FortisBC Electric's energy supply requirements in 2014.

WECA
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 BC. The Waneta Expansion is owned, being developed and will be operated by a limited partnership, the limited partners of which are FortisBC Electric's ultimate parent company, Fortis, which owns a 51% interest, and a wholly-owned subsidiary of each of CPC and CBT. The WECA, which was approved by the BCUC on May 25, 2012, allows FortisBC Electric to purchase capacity over 40 years and is expected to be effective for a 40-year term upon completion of the Waneta Expansion in spring 2015.

Legal Proceedings

The Government 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 Electric dated August 2, 2005. During September 2014, a settlement was reached on the matter and a full release and a consent dismissal of the action has been executed and filed. As FortisBC Electric was insured against this claim, the settlement did not have an impact on the Corporation's 2014 consolidated net earnings.

The Government of British Columbia filed a claim in the B.C. Supreme Court in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which include FortisBC Electric, use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $15 million. While FortisBC Electric has not been served, the company has retained counsel and has notified its insurers.

The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the 2014 Audited Consolidated Financial Statements.

Human Resources

As at December 31, 2014, FortisBC Electric had 500 full-time equivalent employees. Approximately 70% of the employees are represented by IBEW and COPE. The IBEW collective agreement expires January 31, 2018. FortisBC Electric's two COPE collective agreements expire December 31, 2018 and March 31, 2017.

3.3.3 *Eastern Canadian Electric Utilities*

Eastern Canadian Electric Utilities are comprised of the operations of Newfoundland Power, Maritime Electric and FortisOntario.

Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving approximately 259,000 customers in approximately 600 communities. Newfoundland Power met a peak demand of 1,398 MW in 2014. Newfoundland Power owns and operates approximately 11,900 kilometres of T&D lines.

The Corporation, through FortisWest, holds all of the common shares of Maritime Electric, an integrated electric utility that directly supplies approximately 78,000 customers, constituting approximately 90% of electricity consumers on PEI. Maritime Electric purchases most of the energy it distributes to its customers from NB Power, a New Brunswick Crown corporation, through various energy purchase agreements. Maritime Electric owns and operates generating plants with a combined capacity of 150 MW on PEI and met a peak demand of 256 MW in 2014. Maritime Electric owns and operates approximately 5,700 kilometres of T&D lines.

FortisOntario provides integrated electric utility service to approximately 65,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations are comprised of Canadian Niagara Power, Cornwall Electric and Algoma Power. FortisOntario also owns a 10% interest in certain regional electric distribution companies serving approximately 39,000 customers. FortisOntario met a combined peak demand of 264 MW in 2014. FortisOntario owns and operates approximately 3,500 kilometres of T&D lines.

Market and Sales

Annual electricity sales attributable to the Eastern Canadian Electric Utilities were 8,376 GWh in 2014 compared to 8,168 GWh in 2013. Revenue was $1,008 million in 2014 compared to $975 million in 2013.

The following table compares the composition of Eastern Canadian Electric Utilities' 2014 and 2013 revenue and electricity sales by customer class.

Eastern Canadian Electric Utilities
Revenue and Electricity Sales by Customer Class

	Revenue (%)		**GWh Sales (%)**	
	2014	2013	**2014**	2013
Residential	**56.1**	55.2	**56.4**	56.4
Commercial and Industrial	**41.1**	40.7	**43.5**	43.4
Other [(1)]	**2.8**	4.1	**0.1**	0.2
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes revenue from sources other than from the sale of electricity.*

Power Supply

Newfoundland Power
Approximately 93% of Newfoundland Power's energy requirements are purchased from Newfoundland Hydro. The principal terms of the supply arrangements with Newfoundland Hydro are regulated by the PUB on a basis similar to that upon which Newfoundland Power's service to its customers is regulated.

The purchased power rate structure is the basis upon which Newfoundland Hydro charges Newfoundland Power for purchased power and includes charges for both demand and energy purchased. The demand charge is based on applying a rate to the peak-billing demand for the most recent winter season. The energy charge is a two-block charge with a higher second-block charge set to reflect Newfoundland Hydro's marginal cost of generating electricity.

Newfoundland Hydro has a general rate application before the PUB which will establish a new wholesale rate for Newfoundland Power. The outcome of this application, and future changes in supply costs, including costs associated with Nalcor Energy's Muskrat Falls hydroelectric generation development and associated transmission assets, may affect electricity prices in a manner that affects Newfoundland Power's sales.

Newfoundland Power experienced losses of electricity supply from Newfoundland Hydro in January 2013 and January 2014, which prevented Newfoundland Power from meeting all of its customers' requirements. The PUB is conducting an inquiry and hearing into these interruptions. The PUB's consultant filed final reports on the adequacy and reliability of the Island Interconnected system until interconnection with Muskrat Falls on December 18, 2014. These reports did not indicate any material reliability deficiency in Newfoundland Power's system but did identify some weaknesses in Newfoundland Hydro's system. The PUB is currently considering its consultant's reports and has indicated that consideration of longer term issues associated with adequacy and reliability on the Island Interconnected system after interconnection with Muskrat Falls will be addressed in a subsequent phase of its inquiry and hearing process. These aspects of the investigation are expected to continue into 2015.

As a result of the loss of supply and resulting power outages in 2014, the Government of Newfoundland and Labrador has engaged consultants to complete an independent review of the current electricity system in Newfoundland and Labrador. The focus of the review is to examine the operation, management and regulation of provincial electricity systems including the system on the island of Newfoundland. This review is ongoing.

Newfoundland Power operates 28 small generating facilities, which generate approximately 7% of the electricity sold by the company. Newfoundland Power's hydroelectric generating plants have a total capacity of 97 MW. The diesel plants and gas turbines have a total capacity of approximately 5 MW and 37 MW, respectively.

Maritime Electric
Maritime Electric purchased 76% of the electricity required to meet its customers' needs from NB Power in 2014. The balance was met through the purchase of wind energy produced on PEI by stations owned by the PEI Energy Corporation and from company-owned on-Island generation. Maritime Electric's on-Island generation facilities are used primarily for peaking, submarine-cable loading issues and emergency purposes.

Maritime Electric has two take-or-pay contracts for the purchase of either energy or capacity: (i) a fixed pricing contract with NB Power expiring February 29, 2016; and (ii) a transmission capacity contract allowing Maritime Electric to reserve 30 MW of capacity on an international power line into the United States expiring November 2032.

Maritime Electric has entitlement to approximately 4.55% of the output from Point Lepreau for the life of the unit and is required to pay its share of the capital and operating costs of the unit. Point Lepreau recently underwent a refurbishment from 2008 to 2012 to extend the facility's life.

The *Renewable Energy Act* (PEI) requires Maritime Electric to supply 15% of its annual energy sales from renewable energy sources. In 2014 approximately 25% of Maritime Electric's annual energy sales requirement was supplied by renewable energy.

FortisOntario
The power requirements of FortisOntario's service areas are provided from various sources. Canadian Niagara Power purchases its power requirements for Fort Erie and Port Colborne from IESO. Canadian Niagara Power purchases approximately 81% of energy requirements for Gananoque through monthly energy purchases from Hydro One and the remaining 19% is purchased, through the Hydroelectric Contract Initiative, from the five hydroelectric generating plants of the Fortis Generation East Partnership. Algoma Power purchases 100% of its energy from IESO.

Under the Standard Supply Code of the OEB, Canadian Niagara Power and Algoma Power are obliged to provide Standard Service Supply to all its customers who do not choose to contract with an electricity retailer. This energy is provided to customers at either regulated or market prices.

Cornwall Electric purchases substantially all of its power requirements from Hydro-Québec Energy Marketing under two fixed-term contracts. The first contract provides approximately 205 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per year. Both contracts expire in December 2019.

Human Resources

Newfoundland Power
As at December 31, 2014, Newfoundland Power had 665 full-time equivalent employees, of which approximately 50% were members of bargaining units represented by IBEW. Newfoundland Power has two collective agreements governing its union employees represented by IBEW. One bargaining unit is composed predominately of clerical employees and the other predominately of skilled trade workers. Both collective agreements expired on September 30, 2014. Newfoundland Power and IBEW reached a tentative agreement in December 2014, subject to ratification by the members.

Maritime Electric
As at December 31, 2014, Maritime Electric had 177 full-time equivalent employees, of whom approximately 70% were represented by IBEW under a collective agreement expiring December 31, 2018.

FortisOntario
As at December 31, 2014, FortisOntario had 196 full-time equivalent employees, of whom approximately 59% were represented by CUPE, in Cornwall; IBEW in the Niagara region and Gananoque; and Power Workers Union, a CUPE affiliate, in the Algoma region. The expiry dates of the collective agreements are April 30, 2016; February 29, 2016 and July 31, 2016; and December 31, 2016, respectively.

3.4 Regulated Electric Utilities - Caribbean

The Regulated Electric Utilities – Caribbean segment includes Caribbean Utilities and Fortis Turks and Caicos.

Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 28,000 customers. The company met a peak demand of 100 MW in 2014. Caribbean Utilities owns and operates more than 700 kilometres of T&D lines, including 24 kilometres of submarine cable. Fortis holds an approximate 60% (December 31, 2013 - 60%) controlling ownership interest in the utility. Caribbean Utilities is a public company traded on the TSX (TSX:CUP.U).

Fortis Turks and Caicos is comprised of two integrated electric utilities serving approximately 13,000 customers on certain islands in Turks and Caicos. The utilities met a combined peak demand of approximately 37 MW in 2014. Fortis Turks and Caicos owns and operates approximately 600 kilometres of T&D lines.

Market and Sales

Annual electricity sales were 771 GWh in 2014, compared to 749 GWh in 2013. Revenue was $321 million in 2014, compared to $290 million in 2013.

The following table compares the composition of Regulated Electric Utilities - Caribbean's revenue and electricity sales by customer class for 2014 and 2013.

Regulated Electric Utilities - Caribbean Revenue and Electricity Sales by Customer Class				
	Revenue (%)		GWh Sales (%)	
	2014	2013	**2014**	2013
Residential	**44.0**	44.7	**42.6**	42.6
Commercial and Industrial	**54.9**	53.9	**57.4**	57.4
Other [(1)]	**1.1**	1.4	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

[(1)] *Includes revenue from sources other than from the sale of electricity.*

Power Supply

Caribbean Utilities relies upon in-house diesel-powered generation to produce electricity for Grand Cayman. Grand Cayman has neither hydroelectric potential nor inherent thermal resources and the company must rely upon diesel fuel imported to Grand Cayman primarily from refineries in the Caribbean and the Gulf of Mexico. Caribbean Utilities has an installed generating capacity of approximately 132 MW.

In 2012 Caribbean Utilities entered into primary and secondary fuel supply contracts with two different suppliers and is committed to purchasing approximately 60% and 40%, respectively, of Caribbean Utilities' diesel fuel requirements under each of the contracts. Each contract was renewed for an additional 18-month term in September 2014. Caribbean Utilities has the option to renew each contract for a further 18-month term. It also has a five-year contract for the supply of lubricating oil with Automotive Art Limited. These contracts enable Caribbean Utilities to purchase fuel and lubricating oil from the suppliers on what it believes to be competitive terms and pricing. Both the fuel and lubricating oil contracts include disaster recovery and business continuity plans in the event of foreseeable disruptions to supplies to reduce the impact on Caribbean Utilities' operations.

In October 2014 the ERA announced that Caribbean Utilities was the successful bidder for new generation capacity. Caribbean Utilities will develop and operate a new 39.7 MW diesel power plant, including two 18.5 MW diesel generating units and a 2.7 MW waste heat recovery steam turbine. The project cost is estimated at US$85 million and the plant is expected to be commissioned no later than June 2016. Subsequently, in November 2014 the ERA issued a new non-exclusive Electricity Generation License to Caribbean Utilities for a term of 25 years, expiring in November 2039.

Fortis Turks and Caicos relies upon in-house diesel-powered generation, with an installed generating capacity of 76 MW, to produce electricity for its customers.

Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

Human Resources

As at December 31, 2014, Regulated Electric Utilities - Caribbean employed 364 full-time equivalent employees. The 206 employees at Caribbean Utilities and 158 employees at Fortis Turks and Caicos are non-unionized.

3.5 Non-Regulated - Fortis Generation

The following table summarizes the Corporation's non-regulated generation assets by location.

Non-Regulated - Fortis Generation Assets			
Location	**Plants**	**Fuel**	**Capacity (MW)**
Belize	3	hydro	51
British Columbia [(1)]	1	hydro	16
Upstate New York	4	hydro	23
Ontario	7	hydro, thermal	13
Total	**15**		**103**

[(1)] *Once completed, the Waneta Expansion will provide an additional 335 MW of hydroelectric generating capacity in British Columbia.*

Non-regulated generation operations in Belize consist of the 25-MW Mollejon, 7-MW Chalillo and 19-MW Vaca hydroelectric generating facilities. All of the output of these facilities is sold to Belize Electricity under 50-year PPAs expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary BECOL under a franchise agreement with the GOB. In October 2011 the GOB purportedly amended the Constitution of Belize to require majority government ownership of three public utility providers, including Belize Electricity, but excluding BECOL. Fortis, through its subsidiaries, is challenging the legality of these amendments, as it relates to Belize Electricity. The GOB has also indicated it has no intention to expropriate BECOL. Fortis continues to control and consolidate the financial statements of BECOL.

The non-regulated generation operations of FortisBC Inc. include the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. All of the output of Walden is sold to BC Hydro under a long-term contract that cannot be terminated prior to 2024. Non-regulated generation operations in British Columbia also include the Corporation's 51% controlling ownership interest in the Waneta Partnership, with CPC/CBT holding the remaining 49% interest. Fortis will operate and maintain the non-regulated investment when the facility comes into service, which is expected in spring 2015.

The Waneta Partnership commenced construction of the $900 million, 335-MW Waneta Expansion in late 2010, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia. The project is currently on schedule and within budget. Approximately $679 million in total has been spent on the Waneta Expansion since construction began, with $100 million spent in 2014. Key construction activities in 2014 included the substantial completion of civil construction of two power tunnels and transitions, excavation of the trailrace channel, as well as the powerhouse mechanical and electrical auxiliary systems. Removal of the trailrace and intake plugs continued through the end of 2014 and is forecast to be substantially complete in 2015. Assembly continued with the turbine and generator components with the first unit successfully completing the mechanical run test in December. In 2015 approximately $76 million is expected to be spent. Key project activities scheduled for 2015 include the completion of testing and commissioning, marketable power tests followed by substantial completion in the spring of 2015. For additional information refer to Section 3.3.2 of this 2014 Annual Information Form.

Through FortisUS Energy, an indirectly wholly owned subsidiary, the Corporation owns and operates four hydroelectric generating facilities in upstate New York with a combined capacity of approximately 23 MW operating under licences from FERC. All four hydroelectric generating facilities sell energy at market rates through purchase agreements with Niagara Mohawk Power Corporation.

Non-regulated generation operations of FortisOntario are comprised of the operation of a 5-MW gas-powered cogeneration plant in Cornwall. All thermal energy output of this plant is sold to external third parties, while the electricity output is sold to Cornwall Electric. Fortis Generation East Partnership owns and operates six small hydroelectric generating facilities in eastern Ontario with a combined capacity of 8 MW. The electricity produced from these facilities is sold to the Ontario Power Authority, via the Hydroelectric Contract Initiative, under fixed-price contracts.

Market and Sales

Annual energy sales from non-regulated generation assets were 407 GWh in 2014 compared to 386 GWh in 2013. Revenue was $38 million in 2014 compared to $35 million in 2013.

The following table compares the composition of Fortis Generation East Partnership's 2014 and 2013 revenue and energy sales by location.

Non-Regulated - Fortis Generation Revenue and Energy Sales by Location				
	Revenue (%)		**GWh Sales (%)**	
	2014	2013	**2014**	2013
Belize	**71.0**	72.5	**60.3**	64.2
Ontario	**13.2**	15.6	**13.2**	13.1
British Columbia	**5.5**	5.4	**8.3**	7.9
Upstate New York	**10.3**	6.5	**18.2**	14.8
Total	**100.0**	100.0	**100.0**	100.0

Human Resources

As at December 31, 2014, Fortis Generation East Partnership employed 40 full-time equivalent employees, none of whom participate in a collective agreement.

3.6 Non-Regulated – Non-Utility

In 2014, non-utility investments were comprised of Fortis Properties and Griffith. Griffith was acquired as part of the acquisition of CH Energy Group in June 2013 and sold in March 2014.

Fortis Properties owns and operates 23 hotels, comprised of more than 4,400 rooms, in eight Canadian provinces, and owns and operates approximately 2.8 million square feet of commercial office and retail space, primarily in Atlantic Canada. During the fourth quarter of 2014, Fortis Properties substantially completed construction of a 12-storey office building in downtown St. John's, Newfoundland and Labrador. The building features 143,500 of leasable square feet of Class A office space.

In September 2014, the Corporation announced that it would engage in a review of strategic options for its hotel and real estate business. Strategic options may include, but are not limited to, a sale of all or a portion of the assets, a sale of shares of Fortis Properties or an initial public offering.

Revenue was $249 million in 2014 compared to $248 million in 2013. In 2014 Fortis Properties derived approximately 28% of its revenue from real estate operations and 72% of its revenue from hotel operations, consistent with the prior year. Fortis Properties derived approximately 42% of its 2014 operating income from real estate operations and 58% from hotel operations.

The following table sets out the office and retail properties owned by Fortis Properties.

Fortis Properties Office and Retail Properties			
Property	**Location**	**Type of Property**	**Gross Lease Area** *(000s square feet)*
Fortis Place	St. John's, NL	Office	144
Fort William Building	St. John's, NL	Office	188
Cabot Place I	St. John's, NL	Office	137
TD Place	St. John's, NL	Office	99
Fortis Building	St. John's, NL	Office	83
Multiple Office	St. John's, NL	Office and Retail	58[(1)]
Millbrook Mall	Corner Brook, NL	Retail	114
Fraser Mall	Gander, NL	Retail	98
Marystown Mall	Marystown, NL	Retail	92
Fortis Tower	Corner Brook, NL	Office	68
Maritime Centre	Halifax, NS	Office and Retail	564
Brunswick Square	Saint John, NB	Office and Retail	522
Kings Place	Fredericton, NB	Office and Retail	293
Blue Cross Centre	Moncton, NB	Office and Retail	326
Delta Regina	Regina, SK	Office	52
Total			**2,838**

(1) *Excludes Martin Royal building, which building is not available for leasing.*

Revenue per available room at the Hospitality Division of Fortis Properties was $80.61 for 2014 compared to $81.48 for 2013. The change was the result of a 2.5% decrease in occupancy, partially offset by a 1.5% increase in average daily room rate. The average occupancy decreased to 59.9% for 2014 from 61.4% for 2013, while the average daily room rate for 2014 was $134.64, up from $132.70 achieved in 2013.

The hotels owned and managed by Fortis Properties are summarized as follows.

Fortis Properties Hotels			
Hotels	**Location**	**Number of Guest Rooms**	**Function Space** *(000s square feet)*
Delta St. John's Hotel & Conference Centre	St. John's, NL	403	21
Holiday Inn St. John's Government Center	St. John's, NL	252	12
Sheraton Hotel Newfoundland	St. John's, NL	301	16
Mount Peyton Hotel	Grand Falls-Windsor, NL	149	5
Greenwood Inn & Suites Corner Brook	Corner Brook, NL	102	5
Four Points by Sheraton Halifax	Halifax, NS	177	20
Holiday Inn Sydney-Waterfront	Sydney, NS	152	6
Delta Brunswick	Saint John, NB	254	18
Holiday Inn Kitchener-Waterloo & Conference Centre	Kitchener-Waterloo, ON	184	13
Holiday Inn Peterborough-Waterfront	Peterborough, ON	153	7
Holiday Inn Sarnia Hotel & Conference Centre	Point Edward, ON	216	11
Holiday Inn Cambridge	Cambridge, ON	143	6
Holiday Inn & Suites Windsor	Windsor, ON	214	23
Ramada Plaza Calgary Airport Hotel & Conference Centre	Calgary, AB	210	8
Station Park All Suite Hotel	London, ON	126	2
Holiday Inn Conference Centre Edmonton South	Edmonton, AB	224	7
Best Western Plus Winnipeg Airport	Winnipeg, MB	213	8
Hilton Suites Winnipeg Airport	Winnipeg, MB	159	9
Holiday Inn Lethbridge	Lethbridge, AB	119	4
Holiday Inn Express & Suites Medicine Hat	Medicine Hat, AB	93	2
Best Western Plus Sun Country	Medicine Hat, AB	122	1
Holiday Inn Express Kelowna & Conference Centre	Kelowna, BC	190	4
Delta Regina	Regina, SK	274	45
Total		**4,430**	**253**

Human Resources

As at December 31, 2014, Fortis Properties employed approximately 2,300 full-time equivalent employees, approximately 47% of whom are represented by unions listed in the following table.

Fortis Properties Unions			
Property	**Union**	**Expiry of Agreement**	**Number of Unionized Employees**
Holiday Inn St. John's Government Center	Unifor	August 31, 2015	49
Delta St. John's Hotel & Conference Centre	UFCW	December 31, 2016	225
Greenwood Inn & Suites Corner Brook	Unifor	March 11, 2016	44
East Side Mario's St. John's	Unifor	July 31, 2016	99
Holiday Inn Sydney-Waterfront	Unifor	September 30, 2017	76
Delta Brunswick & Brunswick Square	USW	June 30, 2016	117
Delta Regina	Unifor	May 31, 2017	157
St. John's Real Estate	IBEW	April 17, 2016	8
Sheraton Hotel Newfoundland	Unifor	March 31, 2015	181
Holiday Inn & Suites Windsor	UFCW	April 30, 2016	46
Mount Peyton Hotel	UFCW	December 1, 2014 [(1)]	53
Best Western Plus Winnipeg Airport (Maintenance)	Workers' United	June 30, 2017	3
Best Western Plus Winnipeg Airport (Housekeeping)	Workers' United	May 31, 2017	23
Total			**1,081**

[(1)] *Discussions on bargaining are ongoing to reach a new agreement.*

4.0 REGULATION

The Corporation's utilities primarily operate under a cost of service regulation and, in certain circumstances, performance based rate setting mechanisms, and are regulated by the regulatory body in their respective operating jurisdiction. With regulated utilities in nine different jurisdictions, Fortis has significant regulatory expertise.

For information with respect to the nature of regulation and material regulatory decisions and applications associated with each of the Corporation's regulated electric and gas utilities, refer to the "Regulatory Highlights" section of the Corporation's MD&A and to Note 2 of the Corporation's 2014 Audited Consolidated Financial Statements.

5.0 ENVIRONMENTAL MATTERS

The Corporation and its subsidiaries are subject to various federal, provincial, state and municipal laws, regulations and guidelines relating to the protection of the environment including, but not limited to, wildlife, water and land protection, emissions and the proper storage, transportation, recycling and disposal of hazardous and non-hazardous substances. In addition, federal, provincial and state governments have environmental assessment legislation, which is designed to foster better land-use planning and environmental protection through the identification and mitigation of potential environmental impacts of projects or undertakings prior to and after their commencement.

Several key Canadian federal environmental laws and regulations affecting the operations of the Corporation's Canadian subsidiaries include, but are not limited to, the: (i) *Canadian Environmental Assessment Act, 2012;* (ii) *Canadian Environmental Protection Act, 1999*; (iii) *Transportation of Dangerous Goods Act and Regulations*; (iv) *Hazardous Products Act*; (v) *Canada Wildlife Act*; (vi) *Navigation Protection Act*; (vii) *Canada National Parks Act*; (viii) *Fisheries Act;* (ix) *Canada Water*

Act; (x) *National Fire Code of Canada;* (xi) *Pest Control Products Act and Regulations;* (xii) *PCB Regulations;* (xiii) *Species at Risk Act;* (xiv) *Ozone Depleting Substances Regulations;* (xv) *Indian Act* and the duty to consult and accommodate*;* (xvi) *International River Improvements Act;* and (xvii) *Migratory Birds Convention Act, 1994.*

Several key U.S. federal environmental laws and regulations affecting the operations of UNS Energy and Central Hudson include, but are not limited to, the: (i) *Clean Water Act*; (ii) *Safe Drinking Water Act*; (iii) *Clean Air Act*; (iv) *Endangered Species Act*; (v) *Resource Conservation & Recovery Act*; (vi) *Toxic Substances Control Act*; (vii) *Comprehensive Environmental Response, Compensation, and Liability Act*; (viii) *National Environmental Policy Act*; (ix) *Emergency Planning & Community Right to Know Act*; and (x) *Pollution Prevention Act of 1990*.

Environmental risks affecting the Corporation's utility operations include, but are not limited to: (i) hazards associated with the transportation, storage and handling of large volumes of fuel for fuel-powered electricity generating plants, including leaching of the fuel and other operational by-products into the soil, groundwater, nearby watershed areas and open waters; (ii) risk of spills or leaks of petroleum-based products, including PCB-contaminated oil, which are used in the cooling and lubrication of transformers, capacitors and other electrical equipment; (iii) risk related to natural gas discharges; (iv) risk of spills or releases into the environment arising from the improper transportation, storage, handling and disposal of other hazardous substances; (v) GHG and other fuel gas emissions, including natural gas and propane leaks and spills and emissions from the combustion of fuel required to generate electricity; (vi) risk of fire; (vii) risk of disruption to vegetation; (viii) risk of contamination of soil and water near chemically treated poles; (ix) risk of disruption to fish, animals and their habitat as a result of the creation of artificial water flows and levels associated with hydroelectric water storage and utilization; and (x) risk of responsibility for remediation of contaminated properties, whether or not such contamination resulted from the Corporation's utility operations.

There are many provincial, state, and municipal laws, regulations and guidelines that address similar environmental risks as the federal laws, regulations and guidelines, but at a provincial, state or local level. The constant evolution of environmental legislation results in ongoing risks to the Corporation, as its subsidiaries must adjust their business operations to comply.

In addition to changing air emission standards, the management of GHG emissions is a specific environmental concern of the Corporation's Regulated Utilities in Canada and the United States, primarily due to the uncertainties relating to new and emerging federal, provincial and state GHG laws, regulations and guidelines in Canada and the United States. Governmental policy direction is unfolding; however, it remains to be determined whether a GHG air emissions cap or limit may be imposed and to what extent it will impact the Corporation's utilities. Canada has committed to reduce GHG emissions to 17% below 2005 levels by 2020, and the United States has committed to reduce GHG emissions to 30% below 2005 levels by 2030. Both countries are in the process of imposing sectoral requirements, yet it is not certain how the Corporation's subsidiaries will be impacted.

In British Columbia, the *Carbon Tax Act, Clean Energy Act, Greenhouse Gas Reduction (Cap and Trade) Act* and *Greenhouse Gas Reduction Targets Act* and anticipated cap-and-trade regulations specifically affect, or may potentially affect, the operations of the FortisBC Energy companies and FortisBC Electric. To help mitigate uncertainty, the FortisBC Energy companies participate in sector and industry groups in order to monitor the development of emerging regulation and policy.

The Government of British Columbia's Energy Plan and GHG reduction targets present risks and opportunities to the FortisBC Energy companies and, to a lesser degree, FortisBC Electric. These government initiatives continue to place pressure on natural gas consumption and its contribution to GHG emissions. The energy and GHG emissions policies in British Columbia have created opportunities for the FortisBC Energy companies through incentives to expand their deployment of renewable energy, such as biogas, the establishment of a natural gas transportation program, and the expansion of its Energy Efficiency and Conservation Program. Additionally, the *Carbon Tax Act* improves the competitive position of natural gas relative to other fossil fuels, as the tax is based on the amount of carbon dioxide equivalent emitted per unit of energy. Natural gas, therefore, has a lower tax rate than oil or coal products.

British Columbia continues to be a participant in the Western Climate Initiative, which expects to implement a cap-and-trade program to reduce GHG emissions. The FortisBC Energy companies are expected to be covered under the program. If implemented, the cap-and-trade program is expected to have a declining cap on emissions that all applicable facilities must meet, either by reducing emissions internally or by purchasing allowances from other facilities for release of GHG emissions over the capped amounts.

In 2011 the FortisBC Energy companies began reporting their GHG emissions pursuant to the reporting regulation under the *Greenhouse Gas Reduction (Cap and Trade) Act.* In addition, the FortisBC Energy companies continue to report their GHG emissions under Environment Canada's GHG Program. The FortisBC Energy companies have developed capabilities that will support the management of compliance requirements in an upcoming GHG emissions' trading environment, as government policy in that area evolves. The FortisBC Energy companies will also continue to monitor and assess emerging regulations, in particular, the offset and allowance regulations.

The impact of GHG emissions is lower at the Corporation's Canadian regulated electric utilities because their primary business is the distribution of electricity. With respect to FortisAlberta, its operations involve only the distribution of electricity. Additionally, all in-house generating capacity at FortisBC Electric, about 70% at Newfoundland Power, and most of the Corporation's non-regulated generating capacity is hydroelectric, a clean energy source. The 335-MW Waneta Expansion will be a clean renewable hydroelectric energy source when it comes into service in spring 2015. Only a small portion of in-house generation at Canadian regulated electric utilities uses diesel fuel. The Corporation's Canadian regulated electric utilities are indirectly impacted, however, by GHG emissions through the purchase of power generated by suppliers using combustible fuel. Such power suppliers are responsible for compliance with carbon dioxide emissions standards and the cost of compliance with such standards is generally flowed through to end-use consumers.

The *Renewable Energy Act* (PEI) and the recent PEI Energy Accord directly impact the long-term energy supply planning process for PEI. The Act required Maritime Electric to source 15% of its annual energy sales from renewable sources by 2010, which the company met in both 2013 and 2014. Under the PEI Energy Accord, Maritime Electric and the Government of PEI are committed to work collaboratively to increase electricity produced on PEI and sold to Maritime Electric from renewable energy sources, principally wind.

UNS Energy and Central Hudson are subject to regulation by United States federal, state and local authorities related to the environmental effects of their operations.

Central Hudson directly or indirectly owns minimal generating capacity and relies on purchased capacity and energy from third-party providers. Central Hudson is, however, exposed to environmental contingencies associated with MGP's that it and its predecessors owned and operated to serve their customers' heating and lighting needs from the mid-to-late 1800s to the 1950s. The DEC regulates the timing and extent of remediation of MGP sites in New York State. As at December 31, 2014, Central Hudson has recognized approximately US$105 million in associated MGP environmental remediation liabilities. As approved by the PSC, the company is currently permitted to recover MGP site investigation and remediation costs in customer rates. For additional information, refer to the "3.1.2 Central Hudson" section of this 2014 Annual Information Form.

UNS Energy owns significant generating assets. In 2012 the EPA issued final rules for the control of mercury emissions and other hazardous air pollutants from power plants. Based on these rules, TEP's Navajo and Springerville plants may require mercury control equipment by April 2016.

The EPA's Regional Haze Rules impose emission controls on facilities emitting air pollutants that reduce visibility in national parks and wilderness areas. Complying with the EPA's findings, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of TEP's coal-fired generating facilities or for individual joint owners to continue to participate in the units they own at these power plants.

In 2014 the EPA issued proposed carbon emission regulations for existing power plants called the Clean Power Plan. The Clean Power Plan aims to reduce United States carbon emissions to 30% below 2005 levels by 2030. The proposed plan sets carbon emission rates for each state. Using 2012 as a baseline year, Arizona's carbon emission rate for 2030 represents a 52% reduction. The EPA is expected to issue a final rule by summer 2015. In 2014 the EPA also issued a supplemental proposal regarding carbon emissions regulation impacting the Navajo Nation and the Four Corners and Navajo generating stations. The regulation would impose carbon reductions on the Navajo Reservation; however, the reduction requirement is less onerous than what is anticipated from the unit retirements associated with Regional Haze requirements, as discussed above.

TEP will continue working with federal and state regulatory authorities, other neighboring utilities and stakeholders to seek relief from the proposed EPA standard by reducing the disproportionately high level of carbon emissions reduction for Arizona, and to seek relief from the interim and final proposed compliance requirements. In 2014, UNS Energy submitted comments on the proposal on behalf of TEP and its other utility subsidiaries. The proposed rule has been challenged in court and is subject to further legal challenge.

The EPA has been developing regulations for Coal Combustion Residuals placed in landfills and surface impoundments (i.e. ponds). In 2014 the EPA issued a final rule requiring all coal ash and other coal combustion residuals to be treated as a solid waste. UNS Energy does not anticipate significant impacts to current operations at its existing facilities from this final rule.

TEP has in place an Environmental Compliance Adjustor, as approved by the ACC, which allows for the recovery of certain capital carrying costs to comply with government-mandated environmental regulations between rate cases.

While there are environmental laws, regulations and guidelines affecting the Corporation's operations in Grand Cayman and Turks and Caicos Islands, they are less extensive than the laws, regulations and guidelines in Canada and the United States. The United Kingdom's ratification of the United Nations Framework Convention on Climate Change and its Kyoto Protocol were extended to the Cayman Islands in 2007. This framework aims to reduce GHG emissions produced by certain industries. Specific details on the regulations implementing the protocol have yet to be released by the local government of the Cayman Islands and, accordingly, Caribbean Utilities is currently unable to assess the financial impact of compliance with the framework of the protocol.

All of the energy requirements of Caribbean Utilities and Fortis Turks and Caicos are sourced from in-house diesel-powered generation. The more recently installed generators at Caribbean Utilities and Fortis Turks and Caicos have also been designed to provide an increased output per gallon consumed than the older generators, which generate electricity in a more efficient and environmentally friendly manner. Further, exhaust stacks have been designed and installed so as to maximize sound attenuation and optimize exhaust plume dispersion, thereby improving local air quality in accordance with what the utilities believe to be the best industry practice. The use of diesel oil versus heavy fuel oil also results in significantly lower levels of exhaust emissions. The utilities also purchase and store diesel fuel and/or lubricating oil in bulk, thereby decreasing the environmental risks associated with fuel and/or oil handling. Investments have been made in containment areas for the bulk storage of diesel fuel which have been designed to prevent the fuel from coming into contact with soil or groundwater. Caribbean Utilities also uses an underground fuel pipeline for the delivery of fuel from suppliers' distribution terminals on the coast of Grand Cayman to the day-tank holding facilities at the company's generating plant. The pipeline eliminates the need for road transport of fuel along coastline roads.

The key focus of the utilities is to provide reliable cost-effective service with full regard for the safety of employees and the public while operating in an environmentally responsible manner. A focus on safety and the environment is, therefore, an integral and continuing component of the Corporation's operating activities.

Each of the Corporation's utilities has an EMS, with the exception of UNS Energy, which relies on a comprehensive set of environmental protocols. Environmental policies form the cornerstone of the EMS and UNS Energy's environmental protocols, and outline the following commitments by each utility and its employees with respect to conducting business in a safe and environmentally responsible manner: (i) meet and comply with all applicable laws, legislation, policies, regulations and accepted standards of environmental protection; (ii) manage activities consistent with industry practice and in support of the environmental policies of all levels of government; (iii) identify and manage risks to prevent or reduce adverse consequences from operations, including preventing pollution and conserving natural resources; (iv) regularly conduct environmental monitoring and audits of the EMS and environmental protocols, and strive for continual improvement in environmental performance; (v) regularly set and review environmental objectives, targets and programs; (vi) communicate openly with stakeholders including making available the utility's environmental policy and knowledge of environmental issues to customers, employees, contractors and the general public; (vii) support and participate in community based projects that focus on the environment; (viii) provide training for employees and those working on behalf of the utility to enable them to fulfill their duties in an environmentally responsible manner; and (ix) work with industry associations, government and other stakeholders to establish standards for the environment appropriate to the utility's business.

Through an EMS and environmental protocols, documented procedures are in place to control activities that can affect the environment. Common elements of the utilities' EMS and environmental protocols include: (i) regular inspections of fuel and oil-filled equipment in order to identify and correct for potential spills, and spill response systems to ensure that all spills are addressed, and the associated cleanup is conducted in a prompt and environmentally responsible manner; (ii) GHG emissions management; (iii) procedures for handling, transporting, storing and disposing of hazardous substances, including chemically treated poles, asbestos, lead and mercury, where applicable; (iv) programs to mitigate fire-related incidents; (v) programs for the management and/or elimination of PCBs, where applicable; (vi) vegetation management programs; (vii) training and communicating of environmental policies to employees to ensure work is conducted in an environmentally responsible manner; (viii) review of work practices that affect the environment; (ix) waste management programs; (x) environmental emergency response procedures; (xi) environmental site assessments; and (xii) environmental incident reporting procedures. Additionally, Newfoundland Power's EMS addresses water control and dam structure, as well as hydroelectric generating facility operations and the impact of such on fish and the surrounding habitat. FortisBC Electric's EMS addresses the environmental impacts associated with water flows, including on fisheries and critical habitats.

The FortisBC Energy companies, Central Hudson, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and FortisOntario have developed their respective EMSs consistent with the guidelines of ISO 14001, an internationally recognized standard for EMS. Caribbean Utilities operates an EMS associated with its generation operations, which is ISO 14001 certified, and uses an EMS for its T&D operations, which is consistent with ISO 14001 guidelines. Fortis Turks and Caicos' EMS is also expected to be ISO 14001 certified. As part of their respective EMS or protocols, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor performance. External and/or internal audits of the EMS and protocols are performed on a periodic basis. Based on audits last completed, the EMS continue to be effective, properly implemented and maintained, and materially consistent with ISO 14001 guidelines.

Each of the Corporation's Canadian Regulated Electric Utilities that is a member of the CEA is an active participant in the CEA's Sustainable Electricity Program, which was launched in 2009. Participants in the program commit to continuous improvement of their environmental management and performance including reporting annually on environmental and other performance indicators.

In addition to the EMS, various energy efficiency programs and initiatives, which help in reducing GHG emissions, are undertaken by the utilities or offered to customers.

Environmental risks associated with the Corporation's non-regulated generation operations are addressed in a similar manner as the Corporation's regulated electric utilities that operate in the same jurisdiction as the non-regulated generation operations.

The key environmental risks affecting the Corporation's hospitality and real estate operations include, but are not limited to: (i) asbestos and urea-formaldehyde contamination in buildings; (ii) release of ozone-depleting substances from air conditioning and refrigeration equipment; (iii) fuel tank leaks; (iv) mold remediation; and (v) remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. Fortis Properties is committed to meeting the requirements of environmental standards related to its hospitality and real estate operations. In assessing properties being acquired, all must meet environmental standards, including, but not limited to, the appropriate federal, provincial and municipal standards for asbestos, fuel storage, urea-formaldehyde and chlorofluorocarbon-based refrigerants in air conditioning and refrigeration equipment. Properties are also monitored on an ongoing basis to ensure continued environmental compliance.

The Corporation has asset-retirement obligations as disclosed in the notes to its 2014 Audited Consolidated Financial Statements. As at December 31, 2014, a liability of $37 million in asset retirement obligations at UNS Energy, Central Hudson and FortisBC Electric has been recognized. With the exception of those asset retirement obligations recognized at UNS Energy, Central Hudson and FortisBC Electric, liabilities with respect to asset-retirement obligations have not been recorded in the Corporation's 2014 Audited Consolidated Financial Statements, as they could not be reasonably estimated or were determined to be immaterial (including asset-retirement obligations associated with asbestos and chemically treated poles) to the Corporation's consolidated results of operations, cash flows or financial position. The utilities have ongoing programs to identify and replace transformers which are at risk of spillage of oil, and PCBs continue to be removed from service and safely disposed of in compliance with applicable laws and regulations.

Costs associated with environmental protection initiatives (including the development, implementation and maintenance of EMSs and protocols), compliance with environmental laws, regulations and guidelines, and environmental damage did not have a material impact on the Corporation's consolidated results of operations, cash flows or financial position during 2014 and, based on current laws, facts and circumstances, are not expected to have a material effect in 2015. Many of the above costs, however, are embedded in the utilities' operating, maintenance and capital programs and are, therefore, not readily identifiable. At the Corporation's regulated utilities, prudently incurred operating and capital costs associated with environmental protection initiatives, compliance with environmental laws, regulations and guidelines, and environmental damage are eligible for recovery in customer rates. Fortis believes that the Corporation and its subsidiaries are materially compliant with the environmental laws and regulations applicable to them in the various jurisdictions in which they operate.

Oversight of environmental matters is performed at the subsidiary level with regular reporting of environmental matters to the respective subsidiary's Board of Directors.

For further information on the Corporation's environmental risk factors, refer to the "Business Risk Management - Environmental Risks" section of the Corporation's MD&A.

6.0 RISK FACTORS

For information with respect to the Corporation's business risks, refer to the "Business Risk Management" section of the Corporation's MD&A.

7.0 GENERAL DESCRIPTION OF SHARE CAPITAL STRUCTURE

The authorized share capital of the Corporation consists of the following:

(a) an unlimited number of Common Shares without nominal or par value;
(b) an unlimited number of First Preference Shares without nominal or par value; and
(c) an unlimited number of Second Preference Shares without nominal or par value.

As at February 18, 2015, the following Common Shares and First Preference Shares were issued and outstanding.

Share Capital	Issued and Outstanding	Votes per Share [1]
Common Shares	276,349,427	One
First Preference Shares, Series E	7,993,500	None
First Preference Shares, Series F	5,000,000	None
First Preference Shares, Series G	9,200,000	None
First Preference Shares, Series H	10,000,000	None
First Preference Shares, Series J	8,000,000	None
First Preference Shares, Series K	10,000,000	None
First Preference Shares, Series M	24,000,000	None

(1) *The First Preference Shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive, and whether or not such dividends have been declared.*

Convertible Debentures

To finance a portion of the acquisition of UNS Energy, in January 2014, Fortis completed the sale the Convertible Debentures. The Convertible Debentures were sold on an installment basis at a price of $1,000 per Convertible Debenture, of which $333 was paid on closing in January 2014 and the remaining $667 was paid on October 27, 2014, being the Final Installment Date. Prior to the Final

Installment Date, the Convertible Debentures were represented by Installment Receipts, which were traded on the TSX under the symbol "FTS.IR". Since the Final Installment Date occurred prior to the first anniversary of the closing of the offering, holders of Convertible Debentures who paid the final installment in October 2014 received, in addition to the payment of accrued and unpaid interest, a make-whole payment, representing interest that would have accrued from the day following the Final Installment Date to and including January 9, 2015. Approximately $72 million ($51 million after tax) in interest expense associated with the Convertible Debentures, including the make whole payment, was recognized in 2014.

At the option of the holders, each Convertible Debenture was convertible into Common Shares of Fortis at any time after the Final Installment Date but prior to maturity or redemption by the Corporation at a conversion price of $30.72 per Common Shares, being a conversion rate of 32.5521 Common Shares per $1,000 principal amount of Convertible Debentures. On October 28, 2014, approximately 58.2 million Common Shares of Fortis were issued, representing conversion into Common Shares of more than 99% of the Convertible Debentures. As at December 31, 2014, a total of approximately 58.5 million Common Shares of Fortis were issued on the conversion of Convertible Debentures for proceeds of $1.747 billion, net of after-tax expenses. The net proceeds were used to finance a portion of the acquisition of UNS Energy.

Dividend Policy

The following table summarizes the cash dividends declared per share for each of the Corporation's class of shares for the past three years.

	Dividends Declared *(per share)*		
Share Capital	**2014**	**2013**	**2012**
Common Shares	**$1.30**	$1.25	$1.21
First Preference Shares, Series C (1)	**-**	$0.4862	$1.3625
First Preference Shares, Series E	**$1.2250**	$1.2250	$1.2250
First Preference Shares, Series F	**$1.2250**	$1.2250	$1.2250
First Preference Shares, Series G (2)	**$0.9708**	$1.1416	$1.3125
First Preference Shares, Series H	**$1.0625**	$1.0625	$1.0625
First Preference Shares, Series J (3)	**$1.1875**	$1.1875	$0.3514
First Preference Shares, Series K (4)	**$1.0000**	$0.6233	-
First Preference Shares, Series M (5)	**$0.4613**	-	-

(1) *In July 2013 the Corporation redeemed all of the issued and outstanding First Preference Shares, Series C at a redemption price of $25.1456 per share, being equal to $25.00 plus the amount of accrued and unpaid dividends per share.*

(2) *The annual fixed dividend per share for the First Preference Shares, Series G was reset from $1.3125 to $0.9708 for the five-year period from and including September 1, 2013 to but excluding September 1, 2018.*

(3) *The First Preference Shares, Series J were issued in November 2012 at $25.00 per share and are entitled to receive cumulative dividends in the amount of $1.1875 per share annum.*

(4) *The Fixed Rate Reset First Preference Shares, Series K were issued in July 2013 at $25.00 per share and are entitled to receive cumulative dividends in the amount of $1.0000 per share per annum for the first six years.*

(5) *The Fixed Rate Reset First Preference Shares, Series M were issued in September 2014 at $25.00 per share and are entitled to receive cumulative dividends in the amount of $1.0250 per share per annum for the first five years.*

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on Common and Preferred Shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

On December 17, 2014, the Board declared an increase in the quarterly Common Share dividend to $0.34 per share from $0.32 per share, with the first payment to be made on March 1, 2015, to holders of record as of February 17, 2015. Also on December 17, 2014, the Board declared a first quarter 2015 dividend on the First Preference Shares, Series E, F, G, H, J, K and M in accordance with the applicable annual prescribed rate to be paid on March 1, 2015 to holders of record as of February 17, 2015.

Common Shares

Dividends on Common Shares are declared at the discretion of the Board. Holders of Common Shares are entitled to dividends on a pro rata basis if, as, and when declared by the Board. Subject to the rights of the holders of the First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive dividends in priority to or rateably with the holders of the Common Shares, the Board may declare dividends on the Common Shares to the exclusion of any other class of shares of the Corporation.

On the liquidation, dissolution or winding-up of Fortis, holders of Common Shares are entitled to participate rateably in any distribution of assets of Fortis, subject to the rights of holders of First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or rateably with the holders of the Common Shares.

Holders of the Common Shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Fortis, other than separate meetings of holders of any other class or series of shares, and are entitled to one vote in respect of each Common Share held at such meetings.

First Preference Shares, Series E

Holders of the 7,993,500 First Preference Shares, Series E are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. The Corporation may, at its option, redeem all, or from time to time any part of, the outstanding First Preference Shares, Series E by the payment in cash of a sum per redeemed share equal to $25.50 if redeemed during the 12 months commencing June 1, 2014; $25.25 if redeemed during the 12 months commencing June 1, 2015; and $25.00 if redeemed on or after June 1, 2016 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. The Corporation may, at its option, convert all, or from time to time any part of the outstanding First Preference Shares, Series E into fully paid and freely tradeable Common Shares of the Corporation. The number of Common Shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per First Preference Share, Series E, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares at such time. On or after September 1, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first business day of September, December, March and June of each year, into fully paid and freely tradeable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares. If a holder of First Preference Shares, Series E elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference Shares, Series E for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series F

Holders of the 5,000,000 First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. The Corporation may, at its option, redeem for cash the First Preference Shares, Series F, in whole at any time or in part from time to time, at $25.25 per share if redeemed on or after December 1, 2014 but before December 1, 2015, and at $25.00 per share if redeemed on or after December 1, 2015 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series G

Holders of the 9,200,000 First Preference Shares, Series G were entitled to receive fixed cumulative preferential cash dividends at a rate of $1.3125 per share per annum for each year up to and including August 31, 2013. The annual fixed dividend rate per share for the First Preference Shares, Series G was reset to $0.9708 per share per annum for the five-year period from and including September 1, 2013 to but excluding September 1, 2018. For each five-year period after that date, the holders of First Preference Shares, Series G are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying

$25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada bond yield on the applicable reset date plus 2.13%. On September 1, 2018, and on September 1 every five years thereafter, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series G, in whole at any time, or in part from time to time, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series H
Holders of the 10,000,000 First Preference Shares, Series H are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.0625 per share per annum for each year up to but excluding June 1, 2015. For each five-year period after that date, the holders of First Preference Shares, Series H are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada bond yield on the applicable reset date plus 1.45%.

On each Series H Conversion Date, being June 1, 2015, and June 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series H, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series H Conversion Date, the holders of First Preference Shares, Series H, have the option to convert any or all of their First Preference Shares, Series H into an equal number of cumulative redeemable floating rate First Preference Shares, Series I.

Holders of the First Preference Shares, Series I will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada treasury bills plus 1.45%.

On each First Preference Shares, Series I Conversion Date, being June 1, 2020, and June 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On any date after June 1, 2015, that is not a First Preference Shares, Series I Conversion Date, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each First Preference Shares, Series I Conversion Date, the holders of First Preference Shares, Series I have the option to convert any or all of their First Preference Shares, Series I into an equal number of First Preference Shares, Series H.

On any First Preference Shares, Series H Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series H outstanding, such remaining First Preference Shares, Series H will automatically be converted into an equal number of First Preference Shares, Series I. On any First Preference Shares, Series I Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series I outstanding, such remaining First Preference Shares, Series I will automatically be converted into an equal number of First Preference Shares, Series H. However, if such automatic conversions would result in less than 1,000,000 First Preference Shares, Series I or less than 1,000,000 First Preference Shares, Series H outstanding then no automatic conversion would take place.

First Preference Shares, Series J
Holders of the 8,000,000 First Preference Shares, Series J are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.1875 per share per annum. On or after December 1, 2017, the Corporation may, at its option, redeem for cash the First Preference Shares, Series J, in whole at any time or in part from time to time, at $26.00 per share if redeemed before December 1, 2018; at $25.75 per share if redeemed on or after December 1, 2018 but before December 1, 2019; at $25.50 per share if redeemed on or after December 1, 2019 but before December 1, 2020; at $25.25 per share if redeemed on or after December 1, 2020 but before December 1, 2021; and at $25.00 per share if redeemed on or after December 1, 2021 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series K
Holders of the 10,000,000 First Preference Shares, Series K are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.0000 per share per annum for each year up to but excluding March 1, 2019. For each five-year period after that date, the holders of First Preference Shares, Series K are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada bond yield on the applicable reset date plus 2.05%.

On each Series K Conversion Date, being March 1, 2019, and March 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series K, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series K Conversion Date, the holders of First Preference Shares, Series K have the option to convert any or all of their First Preference Shares, Series K into an equal number of cumulative redeemable floating rate First Preference Shares, Series L.

Holders of the First Preference Shares, Series L will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada treasury bills plus 2.05%.

On each First Preference Shares, Series L Conversion Date, being March 1, 2024, and March 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series L at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On any date after March 1, 2019, that is not a First Preference Shares, Series L Conversion Date, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series L at a price of $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each First Preference Shares, Series L Conversion Date, the holders of First Preference Shares, Series L have the option to convert any or all of their First Preference Shares, Series L into an equal number of First Preference Shares, Series K.

On any First Preference Shares, Series K Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series K outstanding, such remaining First Preference Shares, Series K will automatically be converted into an equal number of First Preference Shares, Series L. On any First Preference Shares, Series L Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series L outstanding, such remaining First Preference Shares, Series L will automatically be converted into an equal number of First Preference Shares, Series K. However, if such automatic conversions would result in less than 1,000,000 First Preference Shares, Series L or less than 1,000,000 First Preference Shares, Series K outstanding then no automatic conversion would take place.

First Preference Shares, Series M
Holders of the 24,000,000 First Preference Shares, Series M are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.0250 per share per annum for each year up to but excluding December 1, 2019. For each five-year period after that date, the holders of First Preference Shares, Series M are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada bond yield on the applicable reset date plus 2.48%.

On each Series M Conversion Date, being December 1, 2019, and December 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series M, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series M Conversion Date, the holders of First Preference Shares, Series M have the option to convert any or all of their First Preference Shares, Series M into an equal number of cumulative redeemable floating rate First Preference Shares, Series N.

Holders of the First Preference Shares, Series N will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada treasury bills plus 2.48%.

On each First Preference Shares, Series N Conversion Date, being December 1, 2024, and December 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series N at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On any date after December 1, 2019, that is not a First Preference Shares, Series N Conversion Date, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series N at a price of $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each First Preference Shares, Series N Conversion Date, the holders of First Preference Shares, Series N have the option to convert any or all of their First Preference Shares, Series N into an equal number of First Preference Shares, Series M.

On any First Preference Shares, Series M Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series M outstanding, such remaining First Preference Shares, Series M will automatically be converted into an equal number of First Preference Shares, Series N. On any First Preference Shares, Series N Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series N outstanding, such remaining First Preference Shares, Series N will automatically be converted into an equal number of First Preference Shares, Series M. However, if such automatic conversions would result in less than 1,000,000 First Preference Shares, Series N or less than 1,000,000 First Preference Shares, Series M outstanding then no automatic conversion would take place.

Debt Covenant Restrictions on Dividend Distributions
The Trust Indenture pertaining to the Corporation's $200 million Senior Unsecured Debentures contains a covenant which provides that Fortis shall not declare or pay any dividends (other than stock dividends or cumulative preferred dividends on preferred shares not issued as stock dividends) or make any other distribution on its shares or redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

The Corporation has (i) a $1 billion unsecured committed revolving corporate credit facility, maturing in July 2018, that is available for interim financing of acquisitions and for general corporate purposes, and (ii) a $300 million unsecured non-revolving, non-amortizing term credit facility, the proceeds of which were used to finance a portion of the acquisition of UNS Energy. As of December 31, 2014, $273 million remained outstanding on the $300 million facility, which matures in August 2016. Each credit facility contains a covenant which provides that Fortis shall not declare or pay any dividends or make any other restricted payments if, immediately thereafter, consolidated debt to consolidated capitalization ratio would exceed 65% at any time.

As at December 31, 2014 and 2013, the Corporation was in compliance with its debt covenant restrictions pertaining to dividend distributions, as described above.

8.0 CREDIT RATINGS

Securities issued by Fortis and its utilities, that are currently rated, are rated by one or more credit rating agencies, namely, DBRS, S&P and/or Moody's. The ratings assigned to securities issued by Fortis and its utilities are reviewed by the agencies on an ongoing basis. Credit ratings and stability ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are not recommendations to buy sell or hold securities. Ratings may be subject to revision or withdrawal at any time by the rating organization. The following table summarizes the Corporation's debt credit ratings as at February 18, 2015.

Fortis
Credit Ratings

Company	DBRS	S&P	Moody's
Fortis	A (low), Stable (unsecured debt)	A-, Stable (unsecured debt)	N/A
Caribbean Utilities	A (low), Stable (senior unsecured debt)	A-, Stable (senior unsecured debt)	N/A
Central Hudson [(1)]	N/A	A, Stable (unsecured debt)	A2, Stable (unsecured debt)
FEI [(2)]	A, Stable (secured & unsecured debt)	N/A	A1/A3, Stable (secured/unsecured debt)
FHI [(2)]	BBB (high), Stable (unsecured debt)	N/A	N/A
FortisAlberta	A (low), Positive (senior unsecured debt)	A-, Stable (senior unsecured debt)	N/A
FortisBC Electric	A (low), Stable (secured & unsecured debt)	N/A	Baa1, Stable (unsecured debt)
Fortis Turks and Caicos	N/A	BBB, Stable (senior unsecured debt)	N/A
Maritime Electric	N/A	A, Stable (senior secured debt)	N/A
Newfoundland Power	A, Stable (first mortgage bonds)	N/A	A2, Stable (first mortgage bonds)
TEP [(3)]	N/A	BBB+, Stable (unsecured debt)	Baa1, Positive (senior unsecured debt)
UNS Energy	N/A	N/A	Baa2, Positive (senior secured debt)

(1) *Central Hudson's senior unsecured debt is also rated by Fitch at 'A, Negative'.*
(2) *In January 2015, DBRS affirmed the long-term ratings of the FortisBC Energy companies after the completion of the FortisBC Amalgamation on December 31, 2014.*
(3) *TEP's senior unsecured debt is also rated by Fitch at 'BBB+'.*

DBRS rates debt instruments by rating categories ranging from AAA to D, which represents the range from highest to lowest quality of such securities. DBRS states that: (i) 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; (ii) its 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; and (iii) every rating is based on quantitative and qualitative considerations that are relevant for the borrowing entity. According to DBRS, a rating of A by DBRS is in the middle of three subcategories within the third highest of nine major categories. Such rating is assigned to debt instruments considered to be of satisfactory credit quality and for which protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. Entities rated in the BBB category are considered to have long-term debt 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. The assignment of a (high) or (low) modifier within each rating category indicates relative standing within such category.

S&P long-term debt ratings are on a ratings scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities. S&P uses '+' or '-' designations to indicate the relative standing of securities within a particular rating category. S&P states that its credit ratings are current opinions of the financial security characteristics with respect to the ability to pay under contracts in accordance with their terms. This opinion is not specific to any particular contract, nor does it address the suitability of a particular contract for a specific purpose or purchaser. An issuer rated A is regarded as having financial security characteristics to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than those in higher-rated categories.

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 states that its long-term debt ratings are opinions of relative risk of fixed-income obligations with an original maturity of one year or more and that 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 and such a debt rating is assigned to debt instruments considered to be of medium-grade quality. Debt instruments rated Baa are subject to moderate credit risk and may possess certain speculative characteristics. Debt instruments rated A are considered upper-medium grade and are subject to low credit risk.

Fitch's long-term debt rating are on a rating scale that ranges from AAA to C, which represents the range from highest to lowest qualify of such securities. Fitch uses '+' or '-' designations to indicate the relative standing of securities within a particular rating category. Such modifiers are not added to the AAA rating or to ratings below B. Fitch states that its credit ratings provide an opinion on the relative ability of an entity to meet financial commitments, such as interest, preferred dividends, repayment of principal, insurance claims or counterparty obligations. Fitch's credit ratings do not directly address any risk other than credit risk. A rating of 'A' denotes expectation of low default risk, with strong capacity for payment of financial commitments. A rating of 'BBB+' denotes current expectations of low default risk, with adequate capacity for the payment of financial commitments.

The Corporation pays each of DBRS, S&P and Moody's an annual monitoring fee and a one-time fee in connection with each rated issuance. Other than for certain advisory services provided by S&P during the 2013 fiscal year, Fortis did not pay for or receive any other services from DBRS, S&P or Moody's during the 2013 and 2014 fiscal years.

9.0 MARKET FOR SECURITIES

The Common Shares; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series J; First Preference Shares, Series K and First Preference Shares, Series M of Fortis are listed on the TSX under the symbols FTS, FTS.PR.E, FTS.PR.F, FTS.PR.G, FTS.PR.H, FTS.PR.J, FTS.PR.K and FTS.PR.M, respectively. The Installment Receipts of Fortis were traded on the TSX under the symbol FTS.IR from January 9, 2014 to October 27, 2014, upon the receipt of the final installment of the Convertible Debentures.

The following table sets forth the reported high and low trading prices and trading volumes for the Common Shares; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series J; First Preference Shares, Series K; First Preference Shares, Series M and Installment Receipts on a monthly basis for the year ended December 31, 2014.

Fortis 2014 Trading Prices and Volumes						
	Common Shares			First Preference Shares, Series E		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	30.65	29.78	15,427,305	26.14	25.82	55,264
February	31.09	30.20	9,620,655	26.11	25.80	33,747
March	31.56	30.51	12,777,178	26.24	25.81	18,225
April	32.28	31.35	9,813,038	26.20	25.91	247,732
May	32.86	31.26	12,283,732	26.24	25.82	28,942
June	32.58	31.58	11,025,968	26.09	25.80	11,120
July	33.88	32.14	12,902,845	26.27	26.05	33,096
August	33.83	32.98	11,646,542	26.33	25.80	50,911
September	34.81	33.41	12,093,602	26.11	25.91	75,532
October	37.00	33.84	17,348,129	26.12	25.94	12,440
November	40.83	36.70	27,838,727	26.14	25.77	71,290
December	40.67	37.74	21,788,442	25.99	25.72	23,305

Fortis
2014 Trading Prices and Volumes

Month	First Preference Shares, Series F High ($)	Low ($)	Volume	First Preference Shares, Series G High ($)	Low ($)	Volume
January	23.33	22.22	91,267	24.53	23.97	232,756
February	23.71	22.67	262,017	24.49	24.00	88,365
March	24.10	23.01	70,380	24.75	24.25	167,012
April	24.60	23.81	81,295	25.20	24.54	276,627
May	24.65	23.75	86,608	25.30	24.08	284,273
June	24.37	23.67	138,461	24.93	24.26	183,455
July	24.83	24.27	147,770	25.15	24.66	145,260
August	24.88	24.50	28,940	25.36	24.80	205,490
September	24.79	23.70	64,463	25.13	23.57	175,676
October	24.77	23.69	63,422	25.22	24.40	76,906
November	25.01	24.35	85,441	25.50	24.80	61,259
December	25.01	23.94	61,007	25.39	24.75	76,280

Month	First Preference Shares, Series H High ($)	Low ($)	Volume	First Preference Shares, Series J High ($)	Low ($)	Volume
January	22.00	21.00	112,390	22.90	21.70	198,292
February	21.84	20.90	1,039,870	22.76	22.23	340,425
March	21.89	21.34	162,043	23.47	22.43	261,486
April	22.00	21.59	346,498	24.25	23.20	136,011
May	22.40	21.05	305,651	24.40	23.60	260,905
June	21.64	21.00	331,098	24.10	23.42	95,978
July	21.90	21.21	86,946	24.67	23.85	120,687
August	21.61	20.75	95,093	24.59	24.03	137,744
September	21.25	20.21	154,015	24.34	23.26	211,529
October	21.23	19.95	288,510	24.80	23.41	129,354
November	20.81	20.21	540,634	24.92	24.31	90,292
December	20.50	18.00	537,551	24.99	23.76	105,001

Month	First Preference Shares, Series K High ($)	Low ($)	Volume	First Preference Shares, Series M [(1)] High ($)	Low ($)	Volume
January	24.90	24.27	293,987	-	-	-
February	24.84	24.42	108,014	-	-	-
March	24.87	24.50	258,033	-	-	-
April	25.25	24.80	271,649	-	-	-
May	25.42	24.79	215,657	-	-	-
June	25.29	24.80	176,452	-	-	-
July	25.54	24.85	160,474	-	-	-
August	25.30	24.75	141,563	-	-	-
September	25.21	24.56	215,962	25.40	25.00	2,343,967
October	25.61	24.44	79,512	25.61	25.10	724,545
November	25.69	24.76	84,108	25.85	25.35	812,404
December	25.51	24.31	96,823	25.73	25.15	643,591

Month	Installment Receipts [(2)] High ($)	Low ($)	Volume
January	32.96	29.25	1,301,719
February	32.75	30.50	792,223
March	33.95	31.80	1,613,996
April	37.22	33.70	1,350,380
May	39.29	35.85	1,237,972
June	38.51	35.43	927,018
July	43.00	37.50	2,091,274
August	43.36	39.94	1,150,613
September	46.22	42.16	442,368
October	48.35	42.00	851,150

(1) *The First Preference Shares, Series M were issued in September 2014.*
(2) *The Installment Receipts were traded on TSX from January 9, 2014 to October 27, 2014.*

10.0 DIRECTORS AND OFFICERS

The Board has governance guidelines which cover various items, including director tenure. The governance guidelines provide that Directors of the Corporation are to be elected for a term of one year and, except in appropriate circumstances determined by the Board, be eligible for re-election until the annual meeting of shareholders next following the date on which they achieve age 70 or the 12th anniversary of their initial election to the Board. The following chart sets out the name and municipality of residence of each of the Directors of Fortis as of January 1, 2015, and indicates their principal occupations within five preceding years.

Fortis Directors	
Name	**Principal Occupations Within Five Preceding Years**
TRACEY C. BALL *(1)* Edmonton, Alberta	Ms. Ball, 57, retired in September 2014 as Executive Vice President and Chief Financial Officer of Canadian Western Bank Group. Prior to joining a predecessor bank to Canadian Western Bank in 1987, she worked in public accounting and consulting. Ms. Ball has served on several private and public sector boards, including the Province of Alberta Audit Committee and the Financial Executives Institute of Canada. She currently serves on the City of Edmonton LRT Governance Board. Ms. Ball graduated from Simon Fraser University with a Bachelor of Arts (Commerce). She is a member of the Chartered Professionals Accountants of Canada, the Institute of Chartered Accountants of Alberta, and the Association of Chartered Professional Accountants of British Columbia. Ms. Ball holds an ICD.D designation from the Institute of Corporate Directors. Ms. Ball was appointed to the Audit Committee upon her election to the Board in May 2014. She serves as a director of FortisAlberta and is Chair of that company's Audit Committee.
PETER E. CASE *(1) (2)* Kingston, Ontario	Mr. Case, 60, a Corporate Director, retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. During his 17-year career as senior investment analyst with CIBC World Markets and BMO Nesbitt Burns and its predecessors, Mr. Case's coverage of Canadian and selected U.S. pipeline and energy utilities was consistently rated among the top rankings. Mr. Case was awarded a Bachelor of Arts and an MBA from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto. He was first elected to the Board in May 2005 and has been Chair of the Audit Committee of the Board since March 2011. Mr. Case was a Director of FortisOntario from 2003 through 2010 and served as Chair of the FortisOntario Board from 2009 through 2010. He does not serve as a director of any other reporting issuer.
FRANK J. CROTHERS *(2)* Nassau, Bahamas	Mr. Crothers, 70, is Chairman and Chief Executive Officer of Island Corporate Holdings Limited, Nassau, Bahamas, a private Bahamas-based investment company with diverse interests throughout the Caribbean, North America, Australia and South Africa. For more than 35 years, he has served on many public and private sector boards. For over a decade he was on the Board of Harvard University Graduate School of Education and also served a three-year term as Chairman of CARILEC, the Caribbean Association of Electrical Utilities. Mr. Crothers is the past President of FortisTCI, which was acquired by the Corporation in August 2006. He serves on the Board of Caribbean Utilities. Mr. Crothers was first elected to the Fortis Board in May 2007. He was previously a director of Belize Electricity from 2007 to 2010. Mr. Crothers is also a director of reporting issuers AML Limited and Templeton Mutual Funds.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
IDA J. GOODREAU (3) Bowen Island, British Columbia	Ms. Goodreau, 63, is an Adjunct Professor at Sauder School of Business, University of British Columbia. She is a past President and Chief Executive Officer of LifeLabs. Prior to joining LifeLabs in March 2009, she served as President and Chief Executive Officer of Vancouver Coastal Health Authority from 2002. Ms. Goodreau has held senior leadership roles in several Canadian and international pulp and paper and natural gas companies. She was awarded an MBA and a Bachelor of Commerce, Honours, degree from the University of Windsor and a Bachelor of Arts (English and Economics) from the University of Western Ontario. She has served on numerous private and public sector boards and has been a director of FHI and FortisBC Inc. since 2007 and 2010, respectively. Ms. Goodreau serves as Chair of the Governance Committee of the FortisBC Energy companies and FHI. She was first elected to the Board in May 2009. Ms. Goodreau does not serve as a director of any other reporting issuer.
DOUGLAS J. HAUGHEY (1) (3) Calgary, Alberta	Mr. Haughey, 58, from August 2012 through May 2013, was Chief Executive Officer of The Churchill Corporation, a commercial construction and industrial services company focused on the western Canadian market. From 2010 through its successful sale to Pembina Pipeline in April 2012, he served as President and Chief Executive Officer of Provident Energy Ltd., an owner/operator of natural gas liquids midstream facilities. From 1999 through 2008, he held several executive roles with Spectra Energy and predecessor companies. Mr. Haughey had overall responsibility for its western Canadian natural gas midstream business, was President and Chief Executive Officer of Spectra Energy Income Fund and also led Spectra's strategic development and mergers and acquisitions teams based in Houston, Texas. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with an MBA. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors. He was first elected to the Board in May 2009. Mr. Haughey became a director of FortisAlberta in 2010, and serves as Chair of that Board. Mr. Haughey is also a director of Keyera Corporation.
HARRY McWATTERS (2) Summerland, British Columbia	Mr. McWatters, 69, is President of Vintage Consulting Group Inc., Harry McWatters Inc., and TIME Estate Winery, all of which are engaged in various aspects of the British Columbia wine industry. He is the founder and past President of Sumac Ridge Estate Wine Group. Mr. McWatters was first elected to the Board in May 2007. He was a Director of FHI and FortisBC Inc., where he served as Chair from 2006 through 2010. Mr. McWatters does not serve as a director of any other reporting issuer.
RONALD D. MUNKLEY (2) (3) Mississauga, Ontario	Mr. Munkley, 68, a Corporate Director, retired in April 2009 as Vice Chairman and Head of the Power and Utility Business of CIBC World Markets. While there he acted as lead advisor on over 175 capital markets and strategic and advisory assignments for North American utility clients. Prior to that he was COO at Enbridge Inc. and Chairman of Enbridge Consumer Gas. Previously he was President and CEO of Consumer Gas where he led the company through deregulation and restructuring in the 1990s. He graduated from Queen's University with a Bachelor of Science (Engineering), Honours. Mr. Munkley is a professional engineer and has completed the Executive and Senior Executive Programs of the University of Western Ontario and the Partners, Directors and Senior Officers Certificate of the Canadian Securities Institute. He was first elected to the Board in May 2009. Mr. Munkley also serves as a director of Bird Construction Inc.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
DAVID G. NORRIS *(1) (2) (3)* St. John's, Newfoundland and Labrador	Mr. Norris, 67, a Corporate Director, was a financial and management consultant from 2001 until his retirement in December 2013. Prior to that he was Executive Vice President, Finance and Business Development of Fishery Products International Limited. Previously, he held Deputy Minister positions with the Department of Finance and Treasury Board of the Government of Newfoundland and Labrador. Mr. Norris graduated with a Bachelor of Commerce, Honours, from Memorial University of Newfoundland and an MBA from McMaster University. He was first elected to the Board in May 2005 and was appointed Chair of the Board in December 2010. Mr. Norris served as Chair of the Audit Committee of the Board from May 2006 through March 2011. He was a director of Newfoundland Power from 2003 through 2010 and served as Chair of that Board from 2006 through 2010. Mr. Norris served as a director of Fortis Properties from 2006 through 2010. He does not serve as a director of any other reporting issuer.
MICHAEL A. PAVEY *(1) (3)* Calgary, Alberta	Mr. Pavey, 67, a Corporate Director, retired as Executive Vice President and Chief Financial Officer of Major Drilling Group International Inc. in September 2006. Prior to joining Major Drilling Group International Inc. in 1999, he held senior executive positions, including Senior Vice President and Chief Financial Officer of TransAlta Corporation. Mr. Pavey graduated from University of Waterloo with a Bachelor of Applied Science (Mechanical Engineering) and from McGill University with an MBA. He served as a Director of Maritime Electric from 2001 through 2007 and was Chair of that company's Audit and Environment Committee from 2003 through 2007. Mr. Pavey was first elected to the Board in May 2004 and was appointed Chair of the Human Resources Committee in May 2013. He does not serve as a director of any other reporting issuer.
BARRY V. PERRY Mount Pearl, Newfoundland and Labrador	Mr. Perry, 50, is President and Chief Executive Officer of the Corporation. Prior to his current position at Fortis, he served as President from June 30, 2014 to December 31, 2014 and prior to that served as Vice President, Finance and Chief Financial Officer of the Corporation. Mr. Perry joined the Fortis organization in 2000 as Vice President, Finance and Chief Financial Officer of Newfoundland Power. He earned a Bachelor of Commerce from Memorial University of Newfoundland and is a member of the Association of Chartered Professional Accountants of Newfoundland and Labrador. Mr. Perry serves on the Boards of Fortis utilities in British Columbia, Alberta, Arizona and New York, as well as the Board of Fortis Properties.

(1) *Serves on the Audit Committee.*
(2) *Serves on the Governance and Nominating Committee.*
(3) *Serves on the Human Resources Committee.*

The following table sets out the name and municipality of residence of each of the officers of Fortis as of January 1, 2015, and indicates the office held.

Fortis Officers	
Name and Municipality of Residence	**Office Held**
Barry V. Perry Mount Pearl, Newfoundland and Labrador	President and Chief Executive Officer [(1)]
Karl W. Smith St. John's, Newfoundland and Labrador	Executive Vice President, Chief Financial Officer [(2)]
John C. Walker Kelowna, British Columbia	Executive Vice President, Western Canadian Operations [(3)]
Earl A. Ludlow Paradise, Newfoundland and Labrador	Executive Vice President, Eastern Canadian and Caribbean Operations [(4)]
David C. Bennett St. John's, Newfoundland and Labrador	Vice President, Chief Legal Officer and Corporate Secretary [(5)]
James D. Spinney Mount Pearl, Newfoundland and Labrador	Treasurer [(6)]
Jamie D. Roberts Mount Pearl, Newfoundland and Labrador	Controller [(7)]
Donna G. Hynes St. John's, Newfoundland and Labrador	Assistant Secretary [(8)]

[(1)] *Mr. Perry was appointed President and Chief Executive Officer, effective January 1, 2015, upon the retirement of Mr. H. Stanley Marshall. Mr. Perry became President of Fortis, effective June 30, 2014. Prior to that time, Mr. Perry was Vice President, Finance and Chief Financial Officer of Fortis since 2004.*

[(2)] *Mr. Smith was appointed Executive Vice President, Chief Financial Officer, effective June 30, 2014. Prior to that time, Mr. Smith was President and Chief Executive Officer of FortisAlberta since 2007.*

[(3)] *Mr. Walker was appointed Executive Vice President, Western Canadian Operations, effective August 1, 2014. Prior to that, Mr. Walker was President and Chief Executive Officer of FortisBC Electric since 2005 and, in 2010, he was also appointed President and Chief Executive Officer of the FortisBC Energy companies.*

[(4)] *Mr. Ludlow was appointed Executive Vice President, Eastern Canadian and Caribbean Operations, effective August 1, 2014. Prior to that time, Mr. Ludlow was President and Chief Executive Officer at Newfoundland Power since 2007.*

[(5)] *Mr. Bennett was appointed Vice President, Chief Legal Officer and Corporate Secretary, effective September 19, 2014. Prior to that time, Mr. Bennett was Vice President, Operations Support, General Counsel and Corporate Secretary at FortisBC Inc. since 2013.*

[(6)] *Mr. Spinney was appointed Treasurer, effective March 20, 2013. Prior to that time, Mr. Spinney was Manager, Treasury at Fortis since October 2002.*

[(7)] *Mr. Roberts was appointed Controller, effective March 20, 2013. Prior to that time, Mr. Roberts was Vice President, Finance and Chief Financial Officer of Fortis Properties since July 2008.*

[(8)] *Ms. Hynes was appointed Assistant Secretary, effective December 8, 1999. She joined Fortis as Manager, Investor and Public Relations in October 1999 and, prior to that time, was employed by Newfoundland Power.*

As at December 31, 2014, the directors and officers of Fortis, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 663,405 Common Shares, representing 0.2% of the issued and outstanding Common Shares of Fortis. The Common Shares are the only voting securities of the Corporation.

11.0 AUDIT COMMITTEE

11.1 Education and Experience

The education and experience of each Audit Committee Member that is relevant to such Member's responsibilities as a Member of the Audit Committee are set out below. As at December 31, 2014, the Audit Committee was composed of the following persons.

Fortis Audit Committee	
Name	**Relevant Education and Experience**
PETER E. CASE *(Chair)* Kingston, Ontario	Mr. Case retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. He was awarded a Bachelor of Arts and an MBA from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto.
TRACEY C. BALL Edmonton, Alberta	Ms. Ball retired in September 2014 as Executive Vice President and Chief Financial Officer of Canadian Western Bank Group. Ms. Ball has served on several private and public sector boards, including the Province of Alberta Audit Committee and the Financial Executives Institute of Canada. She currently serves on the City of Edmonton LRT Governance Board. She graduated from Simon Fraser University with a Bachelor of Arts (Commerce). She is a member of the Canadian Chartered Professional Accountants of Canada, the Institute of Chartered Accountants of Alberta, and the Association of Chartered Professional Accountants of British Columbia. She holds an ICD.D designation from the Institute of Corporate Directors.
DOUGLAS J. HAUGHEY Calgary, Alberta	Mr. Haughey, from August 2012 through May 2013, was Chief Executive Officer of The Churchill Corporation. Prior to that, he served as President and Chief Executive Officer of Provident Energy Ltd. and held several executive roles with Spectra Energy and predecessor companies. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with an MBA. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors.
DAVID G. NORRIS St. John's, Newfoundland and Labrador	Mr. Norris was a financial and management consultant from 2001 until his retirement in December 2013. Prior to that he was Executive Vice President, Finance and Business Development of Fishery Products International Limited. He graduated with a Bachelor of Commerce, Honours, from Memorial University of Newfoundland and an MBA from McMaster University.
MICHAEL A. PAVEY Calgary, Alberta	Mr. Pavey retired as Executive Vice President and Chief Financial Officer of Major Drilling Group International Inc. in September 2006. Prior to joining Major Drilling Group International Inc. in 1999, he held senior executive positions, including Senior Vice President and Chief Financial Officer of TransAlta Corporation. Mr. Pavey graduated from University of Waterloo with a Bachelor of Applied Science (Mechanical Engineering) and from McGill University with an MBA.

The Board has determined that each of the Audit Committee Members is independent and financially literate. Independent means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110 - *Audit Committees*. Financially literate means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be raised by the Corporation's 2014 Audited Consolidated Financial Statements.

11.2 Audit Committee Mandate

The text of the Corporation's Audit Committee Mandate is detailed below.

A. Objective

The Committee shall provide assistance to the Board by overseeing the external audit of the Corporation's annual financial statements and the accounting and financial reporting and disclosure processes and policies of the Corporation.

B. Definitions

In this mandate:

"**AIF**" means the Annual Information Form filed by the Corporation;

"**Committee**" means the Audit Committee appointed by the Board pursuant to this mandate;

"**Board**" means the board of directors of the Corporation;

"**Corporation**" means Fortis Inc.;

"**Director**" means a member of the Board;

"**Financially Literate**" means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be present in the Corporation's financial statements;

"**External Auditor**" means the firm of chartered professional accountants, registered with the Canadian Public Accountability Board or its successor, and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

"**Independent**" means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in National Instrument 52-110;

"**Internal Auditor**" means the person employed or engaged by the Corporation to perform the internal audit function of the Corporation;

"**Management**" means the senior officers of the Corporation;

"**MD&A**" means the Corporation's management discussion and analysis prepared in accordance with National Instrument 51-102F1 in respect of the Corporation's annual and interim financial statements; and

"**Member**" means a Director appointed to the Committee.

C. Composition and Meetings

1. The Committee shall be appointed annually by the Board and shall be comprised of three (3) or more Directors, each of whom is Independent and Financially Literate and none of whom is a member of Management or an employee of the Corporation or of any affiliate of the Corporation.

2. The Board shall appoint a Chair of the Committee on the recommendation of the Corporation's Governance and Nominating Committee, or such other committee as the Board may authorize.

3. The Committee shall meet at least four (4) times each year and shall meet at such other times during the year as it deems appropriate. Meetings of the Committee shall be held at the call (i) of the Chair of the Committee, or (ii) of any two (2) Members, or (iii) of the External Auditor.

4. The President and Chief Executive Officer, the Executive Vice President, Chief Financial Officer, the External Auditor and the Internal Auditor, shall receive notice of, and (unless otherwise determined by the Chair of the Committee) shall attend all meetings of the Committee.

5. A quorum at any meeting of the Committee shall be three (3) Members.

6. The Chair of the Committee shall act as chair of all meetings of the Committee at which the Chair is present. In the absence of the Chair from any meeting of the Committee, the Members present at the meeting shall appoint one of their Members to act as Chair of the meeting.

7. Unless otherwise determined by the Chair of the Committee, the Secretary of the Corporation shall act as secretary of all meetings of the Committee.

D. Oversight of the External Audit and the Accounting and Financial Reporting and Disclosure Processes and Policies

The primary purpose of the Committee is oversight of the Corporation's external audit and the accounting and financial reporting and disclosure processes and policies on behalf of the Board. Management of the Corporation is responsible for the selection, implementation and maintenance of appropriate accounting and financial reporting principles and policies and internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations. Management is responsible for the preparation and integrity of the financial statements of the Corporation.

1. Oversight of the External Audit

   The oversight of the external audit pertains to the audit of the Corporation's annual financial statements.

   1.1. The Committee is responsible for the evaluation and recommendation of the External Auditor to be proposed by the Board for appointment by the shareholders.

   1.2. In advance of each audit, the Committee shall review the External Auditor's audit plan including the general approach, scope and areas subject to risk of material misstatement.

   1.3. The Committee is responsible for approving the terms of engagement and fees of the External Auditor, including any non-audit services provided by the External Auditor.

   1.4. The Committee shall review and discuss the Corporation's annual audited financial statements, together with the External Auditor's report thereon, and MD&A with Management and the External Auditor to gain reasonable assurance as to the accuracy, consistency and completeness thereof. The Committee shall meet privately with the External Auditor. The Committee shall oversee the work of the External Auditor and resolve any disagreements between Management and the External Auditor.

   1.5. The Committee shall use reasonable efforts, including discussion with the External Auditor, to satisfy itself as to the External Auditor's independence as defined in Canadian Auditing Standard – 260.

2. Oversight of the Accounting and Financial Reporting and Disclosure Processes

   2.1. The Committee shall recommend the annual audited financial statements together with the MD&A for approval by the Board.

   2.2. The Committee shall review the interim unaudited financial statements with the External Auditor and Management, together with the External Auditor's review engagement report thereon.

2.3. The Committee shall review and approve publication of the interim unaudited financial statements together with notes thereto, the interim MD&A and earnings media release on behalf of the Board.

2.4. The Committee shall review and recommend approval by the Board of the Corporation's AIF, Management Information Circular, any prospectus and other financial information or disclosure documents to be issued by the Corporation prior to their public release.

2.5. The Committee shall use reasonable efforts to satisfy itself as to the integrity of the Corporation's financial information systems, internal control over financial reporting and the competence of the Corporation's accounting personnel and senior financial management responsible for accounting and financial reporting.

2.6. The Committee shall use reasonable efforts to satisfy itself as to the appropriateness of the Corporation's material financing and tax structures.

2.7. The Committee shall be responsible for the oversight of the Internal Auditor.

2.8. The Committee shall monitor and report on the development of the Enterprise Risk Management Program.

3. Oversight of the Audit Committee Mandate and Policies

On a periodic basis, the Committee shall review and report to the Board on the Audit Committee Mandate as well as on the following policies:

3.1. Policy on Reporting Allegations of Suspected Improper Conduct and Wrongdoing;

3.2. Derivative Instruments and Hedging Policy;

3.3. Pre-Approval of Audit and Non-Audit Services Policy;

3.4. Hiring from Independent Auditing Firms Policy;

3.5. Policy on the Role of the Internal Audit Function;

3.6. Disclosure Policy; and

3.7. any other policies that may be established, from time to time, relating to accounting and financial reporting and disclosure processes; oversight of the external audit of the Corporation's financial statements; and oversight of the internal audit function.

4. Retaining and Compensating Advisors

The Committee shall have the sole authority to engage independent counsel and any other advisors as the Committee may deem appropriate in its sole discretion and to set the compensation for any advisors employed by the Committee. The Committee shall not be required to obtain the approval of the Board in order to retain or compensate such consultants or advisors.

E. Reporting

The Chair of the Committee, or another designated Member, shall report to the Board at each regular meeting on those matters which were dealt with by the Committee since the last regular meeting of the Board.

F. Other

1. The Committee shall perform such other functions as may, from time to time, be assigned to the Committee by the Board.

11.3 Pre-Approval Policies and Procedures

The Audit Committee has established a policy which requires pre-approval of all audit and non-audit services provided to the Corporation and its subsidiaries by the Corporation's External Auditor. The Pre-Approval of Audit and Non-Audit Services Policy describes the services which may be contracted from the External Auditor and the limitations and authorization procedures related thereto. This policy defines services such as bookkeeping, valuations, internal audit and management functions which may not be contracted from the External Auditor and establishes an annual limit for permissible non-audit services not greater than the total fee for audit services. Audit Committee pre-approval is required for all audit and non-audit services.

11.4 External Auditor Service Fees

Fees incurred by the Corporation for work performed by Ernst & Young LLP, the Corporation's External Auditors, during each of the last two fiscal years for audit, audit-related, tax, and non-audit services were as follows.

Fortis External Auditor Service Fees ($ thousands)		
Ernst & Young LLP	**2014**	2013
Audit Fees	**4,601**	3,190
Audit-Related Fees	**748**	673
Tax Fees	**119**	221
Non-Audit Fees	**48**	-
Total	**5,516**	4,084

Audit fees were higher in 2014 mainly due to work performed by Ernst & Young LLP related to the acquisition and financing of UNS Energy, which was acquired on August 15, 2014, and the annual audit and the quarterly review of UNS Energy. Non-audit services related to work performed at UNS Energy during 2014. The non-audit fees were pre-approved by UNS Energy's Audit Committee and do not impair the independence of Ernst & Young LLP.

12.0 TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares and First Preference Shares of Fortis is Computershare Trust Company of Canada in Halifax, Montréal and Toronto.

Computershare Trust Company of Canada
8th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.investorcentre.com/fortisinc

13.0 AUDITORS

The auditors of the Corporation are Ernst & Young LLP, Chartered Professional Accountants, Fortis Place, Suite 800, 5 Springdale Street, St. John's, NL, A1E 0E4. The consolidated financial statements of the Corporation for the fiscal year ended December 31, 2014 have been audited by Ernst & Young LLP. Ernst & Young LLP report that they are independent of the Corporation in accordance with the Rules of Professional Conduct of the Association of Chartered Professional Accountants of Newfoundland and Labrador.

14.0 ADDITIONAL INFORMATION

Reference is made to the MD&A and 2014 Audited Consolidated Financial Statements, which are incorporated herein by reference. Additional information relating to the Corporation can be found on SEDAR at www.sedar.com.

Further additional information, including officers' and directors' remuneration and indebtedness, principal holders of the securities of Fortis, options to purchase securities and interests of insiders in material transactions, where applicable, will be contained in the management information circular of Fortis to be dated on or about March 20, 2015 for the May 7, 2015 annual meeting of shareholders.

Requests for additional copies of the above-mentioned documents, as well as the 2014 Annual Information Form, should be directed to the Corporate Secretary, Fortis, P.O. Box 8837, St. John's, NL, A1B 3T2 (telephone: 709.737.2800). In addition, such documentation and additional information relating to the Corporation is contained on the Corporation's website at www.fortisinc.com.

Attachment 33.1

October 8, 2015

GROUP OF SEVEN PAINT MODERATE GROWTH PICTURE

Highlights

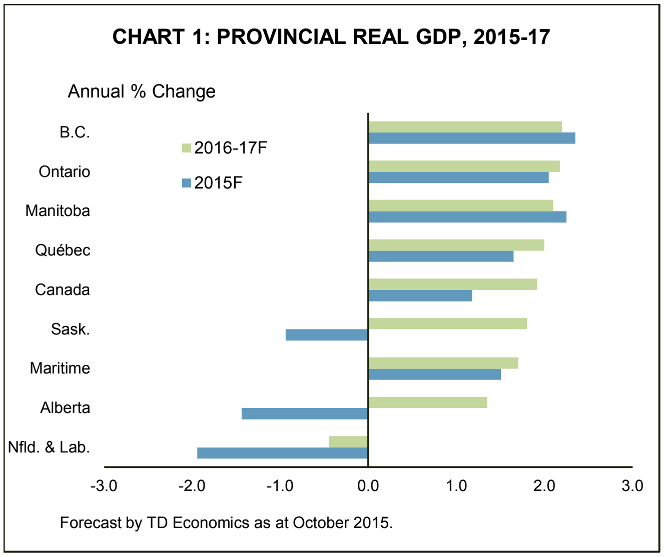
- Economic growth projections have been revised lower across most regions relative to our July forecast. While this year's weak performance has been concentrated in the oil-producing provinces, export activity across most regions underperformed our previous expectations in the first half the year.
- The three oil-producing provinces are forecast to be in recession this year as the impact from low oil prices resonates across these economies. Crude oil prices are expected to begin a recovery next year, but not to levels that would be consistent with a V-shaped rebound in investment and growth in oil-rich regions. As such, Alberta and Saskatchewan are expected to record only modest expansions over the 2016-17 period. In Newfoundland and Labrador, real GDP is expected to contract further next year before stabilizing in 2017.
- Across all other regions, the medium-term outlook can be characterized as continued moderate and steady growth. British Columbia, Ontario and Manitoba are projected to top the growth charts. These regions are well positioned to capitalize on rising export demand. In Ontario and B.C., surging home resale markets will also provide an added lift to consumer spending in the near term.

The extreme weakness in commodity markets and the contraction of the Canadian economy during the first half of this year have emerged as prominent stories. This edition of the Provincial Economic Forecast (PEF) highlights the extent to which this year's softness has been concentrated in the oil-producing provinces of Alberta, Saskatchewan and Newfoundland and Labrador, which together stand to contract by a combined 1.4% in real terms in 2015. This contrasts starkly with estimated economic growth of 2% on average in the remaining seven provinces, which is not booming but respectable.

Looking ahead, the tough times are likely to endure in commodity markets and in provinces that rely on resource-driven activity. Commodity market conditions should begin firming towards the end of next year, but the pace of improvement is likely to be gradual and slow to ripple through to both investment and job markets in these provincial economies. As such, economic growth in Alberta and Saskatchewan is likely to resume next year but remain well below the national average, while Newfoundland and Labrador is projected to remain in contraction territory. In 2017, these regions are projected to take another step in the right direction, but even then, expansions in these provinces are likely to be relatively modest and well below the pace they have grown at historically.

Elsewhere, the medium-term picture can be characterized as continued moderate and steady growth, led by British Columbia, Ontario and Manitoba. Despite the fact that this pack of seven have managed to keep their heads above water, we have still shaved back economic growth expectations in some of these regions relative to our last quarterly forecast in July. The over-riding disappointment has largely surrounded export sectors, where activity generally underperformed our previous expectations throughout most of the first half of the year. The good news is that provincial export growth managed to rebound strongly in June and July. And, despite moving lower in August, real non-energy exports remain 4.3%

Derek Burleton, VP & Deputy Chief Economist, 416-982-2514
Jonathan Bendiner, Economist 416-307-5968



above its May reading. With the U.S. economy expected to gain further ground going forward and consumer spending performances likely to remain decent, the stage is set for continued moderate economic growth and declining unemployment rates across most of the oil-consuming provinces over the next few years.

Weakness in oil-producing economies to drag out

In tandem with the descent in crude oil prices in recent months, this year's estimated contractions in Alberta, Saskatchewan and Newfoundland & Labrador have been deepened relative to the July forecast. Capital spending in the oil and gas sector is expected to drop by some 40% in 2015, dealing a major blow to the non-residential and engineering construction sector – as well as support activities for mining, oil and gas – in the oil patch. Investment activity in Newfoundland and Labrador has managed to remain resilient in 2015. But, in contrast to Alberta, where oil output has expanded further this year, production of crude in Newfoundland and Labrador has been in steep decline (down nearly 20% Y/Y in the first half of 2015). While the headwinds from declining oil prices have been the main culprit, other factors – including drought conditions and wildfires across much of the Prairies – have also conspired against these economies.

Although the latter factors are generally transitory in nature, the impacts from the oil price down cycle are expected to drag out. In light of substantial excess supply in world oil markets, a meaningful recovery in WTI crude prices to $65 per barrel is not expected until 2017. Even then, it will take time for higher prices to translate into increased capital spending. In the meantime, the impact of weaker incomes will continue to permeate though the economy – including jobs markets (which have held up well so far this year in Alberta but we expect the shoe to drop in the second half of this year).

Despite the weak outlook in the Canadian oil patch, the magnitude of the recession in Alberta and Saskatchewan is still likely to fall short of that suffered in the aftermath of the 2008-09 global financial crisis. In Saskatchewan, the economy is not as reliant on its oil sector as Alberta and can rely on improved prospects in other industries – such as potash mining – over the forecast period. One key distinction in Alberta is the large housing market bubble that was amassed and which ultimately unwound in 2009 and 2010, delivering significant strains on the economy. Heading into the current oil price slump, market conditions in Alberta were exhibiting less signs of froth, which should set the stage for a comparatively smaller home price correction in the coming months. This relative resilience is consistent with the performance of home prices so far in 2015.

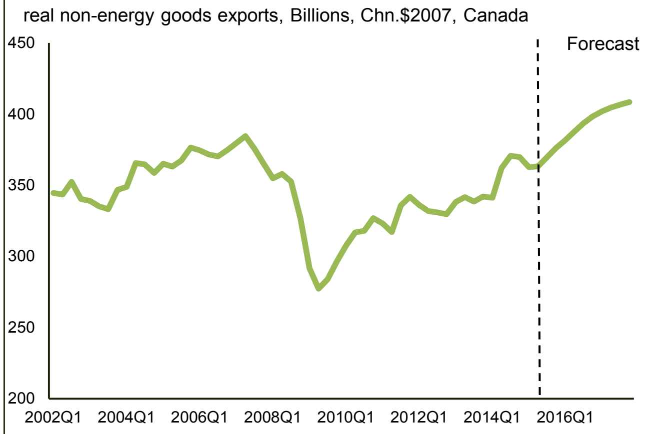
All told, over the 2016-17 period, economic growth is expected to return to Alberta (+1.4% per year on average) and Saskatchewan (+1.8%). However, these rates represent less than half of their recent cruising speeds coming out of the 2008-09 recession. In Newfoundland and Labrador, real GDP is expected to merely stabilize by 2017, as oil production remains in a longer-term downtrend before the Hebron off shore oil site comes fully on line in late 2017 and capital spending eases from this year's still-elevated level.

Rest of Canada to record modest growth

Other provincial economies have fared better, but economic growth performances have still managed to disappoint in the first half of the year. Part of the story appeared to reflect demand trends in the U.S., where growth was slow out of the gate in 2015. Softer-than-expected exports, combined with increased volatility in financial markets, likely led to delays in investment. Consumer spending performances were also more mixed, with shopping malls showing more strength in Ontario and British Columbia, while consumers in Québec, Manitoba and the Maritimes demonstrated more caution.

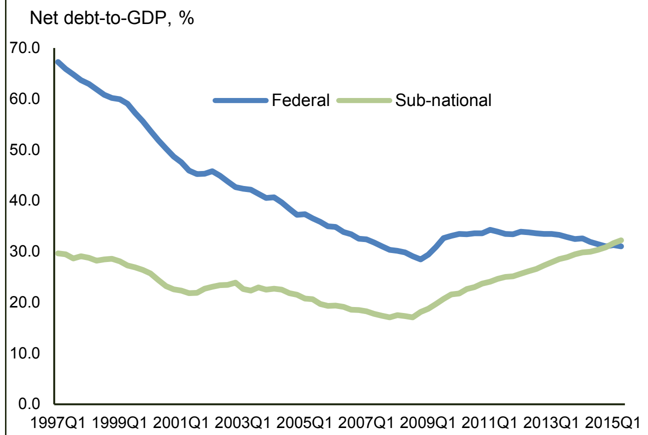
The most recent indicators bode well for a broad-based acceleration in growth in the oil-consuming regions in the second half of 2015 and into 2016. Most encouragingly, non-energy exports have been showing signs of life in response to a revving up U.S. economy and a low Canadian dollar.

CHART 2: NON-ENERGY EXPORTS EXPECTED TO DRIVE EXPORT MARKETS ACROSS CANADA



Source: Haver Analytics. Forecast | Estimate by TD Economics as at October 2015.

CHART 3: DEBT BURDEN AT SUB-NATIONAL LEVEL SURPASSES FEDERAL



Source: Haver Analytics.

The combination of solid U.S. economic growth and a soft Canadian dollar (hitting a low of 73 US cents by early 2016) should keep exports as a major source of provincial growth (see Chart 2). Within service exports, growing tourist traffic from the U.S. is expected to provide a particular boost to provincial economies.

Prospects for household spending remain decent outside of the commodity-affected areas. Despite a likely increase in U.S. short-term interest rates, the Bank of Canada is expected to keep its overnight rate steady until the latter part of 2017 in light of the continued adverse impact of low commodity prices on trend growth. Household spending is also expected to benefit in the near term from strong housing resale activity. This year, headlines have put the focus on the piping-hot growth in sales and prices in Ontario and British Columbia. However, after a few years of softening, sales activity in Québec and the Maritimes have been quietly gaining strength in response to reductions in interest rates earlier this year. As affordability challenges continue to intensify, markets in B.C. and Ontario are expected to record a tapering in sales and price growth in 2016 and into 2017. But, barring a shock to employment or interest rates (which we view as unlikely), corrections in these regions are likely to be orderly.

This year, employment has continued to grow modestly on average in all oil-consuming provinces with the exception of PEI and New Brunswick. In 2016 and 2017, these latter two provinces are expected to join the bandwagon in posting modest net new jobs. Also, a number of provinces – notably Ontario and British Columbia – are likely to benefit from stronger inflows through interprovincial migration.

Most provinces – commodity- and non-commodity-oriented alike – will continue to face a challenging fiscal environment. Among provincial governments, only British Columbia, Saskatchewan and Québec are either in a surplus position or poised to balance in the year ahead. For the first time on record, the combined provincial and local government debt burden is higher than that of the federal government (see Chart 3). A continued emphasis on restraint to government operating budgets represents an ongoing headwind to economies and labour markets from coast to coast. That said, governments have tabled capital spending plans that will provide some much needed infrastructure support, which should help to boost economic growth in both the short and long-run.

All told, the seven oil-consuming regions look well positioned to record modest but steady growth over the next few years. Among these seven provinces, British Columbia and Ontario enjoy the most promising outlook, with real GDP gains averaging around 2.2% in 2016 and 2017. Following closely on their coat-tails will be Manitoba and Québec. These regions enjoy comparatively favourable demographics relative to the Maritime region, where annual expansions are expected to average around 1.6%.

BRITISH COLUMBIA

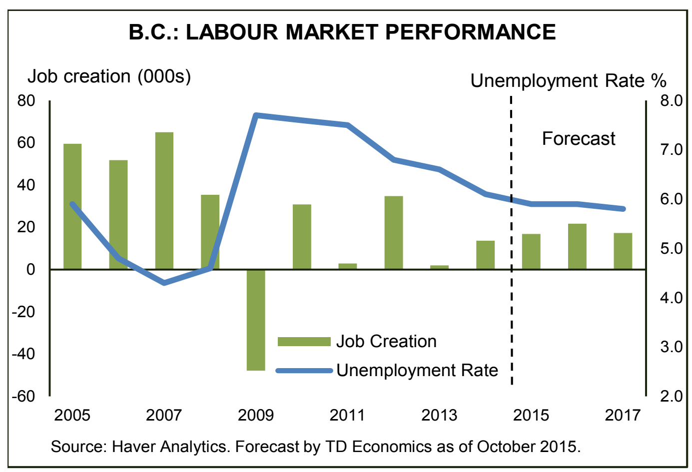
- The outlook for B.C. is the brightest among the provinces. Real GDP growth is estimated at 2.5% in 2015, more than twice the national rate. Over the 2016-17 period, we expect B.C.'s pace of expansion to remain healthy, at just above 2% annually.
- The goods-producing sector has been surging in 2015. Natural gas production is up 9% (YTD Y/Y) in the first half of 2015 as output from the Montney play continues to advance. That said, prices have fallen this year leading to a decline in the value of gas exports. Better news has emanated from the province's manufacturing sector, which has led the pack in Canada, with a nominal sales gain of close to 5% (YTD, Y/Y) through the first half of the year. The $8.3 billion military shipbuilding contract, which commenced production in June, will provide an added boost to activity over the near term. In the mining sector, a cut in coal production in 2015Q3 will weigh on activity this year.
- Within the services sector, a booming resale housing market has been supporting consumer spending activity both directly through related purchases and indirectly through wealth effects. Retail sales are up more than 7% (YTD, Y/Y) through July – leaps and bounds ahead of any other region in Canada. While two cuts to the overnight rate this year has boosted housing demand in 2015, we don't expect the same degree of momentum will be sustained next year as bond yields likely grind higher and affordability challenges become more magnified.
- Tourism activity is also showing increased strength this year. The numbers of travelers entering B.C. is up around 9% so far in 2015. Over the forecast period tourism activity is expected to continue to record solid gains based on a weaker Loonie and our expectation of stronger incomes Stateside.
- Job creation has remained steady in B.C. this year, reflecting solid showings in the manufacturing, transportation and warehousing and health care and social assistance sectors. Look for annual average employment gains of around 20K in 2016-17 with the unemployment rate expected to hover just below 6%. Labour force growth is expected to benefit from rising interprovincial migration, which will help counterbalance the impact of B.C.'s older population.

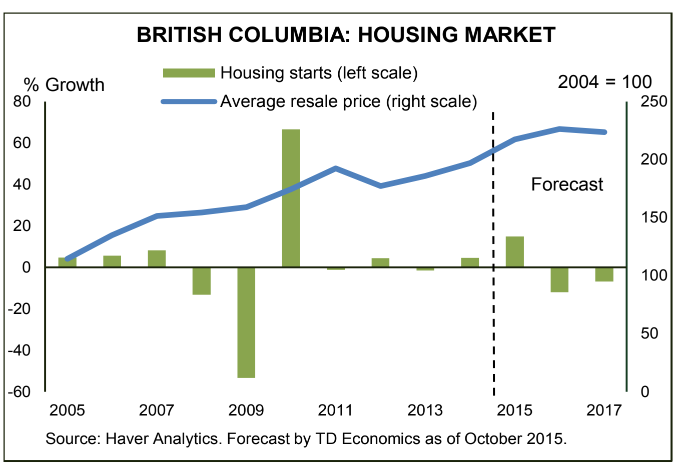
BRITISH COLUMBIA - TD ECONOMICS' FORECASTS

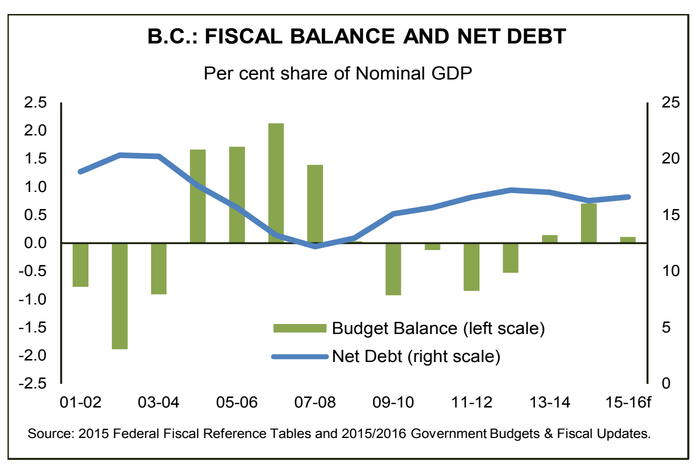
Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	1.9	2.7	2.5	2.4	2.1
Nominal GDP	3.2	4.5	3.5	4.4	4.4
Employment	0.1	0.6	0.7	1.0	0.8
Unemployment rate (%)	6.6	6.1	5.9	5.9	5.8
Consumer Price Index	-0.1	1.0	1.1	2.0	2.1
Retail trade	2.4	5.6	7.5	4.1	2.9
Housing starts	-1.5	4.6	14.9	-11.9	-6.8
Existing home sales	7.8	15.2	19.3	-7.4	-14.1
Avg. existing home price	4.8	6.1	10.3	4.2	-1.2

E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics







ALBERTA

- The drop in oil prices since mid-July 2014 has pushed the Alberta economy into a recession this year. We estimate that real GDP contracted 1.4% in 2015. Crude oil prices are expected to begin a recovery next year, but not to levels that would be consistent with a V-shaped rebound in investment and growth in the province. As such, economic growth is forecast to resume over the 2016-17, but at a very modest rate of around 1.4% per year.
- Output in the construction sector is projected to contract by more than 20% this year. This largely reflects a steep 25% decline in non-residential and engineering construction. Housing starts are also forecast to decline by some 10% this year. On the flip side, oil production is still on track to expand this year. Looking ahead, construction activity is assumed to move lower over the 2016-17 period. Our lower-for-longer oil price forecast has delayed prospects for a meaningful pick up in oil-related capital spending. Due to the long investment horizons attached to existing non-conventional oil projects, gains in crude output are forecast to remain in positive territory over the next few years.
- Income growth as measured by nominal GDP will take a big hit in 2015, falling by an estimated 9%, impacting housing and consumer markets. Both existing home sales and prices are forecast to contract over the next two years.
- Job creation has held up well in Alberta, with employment up 1.7% Y/Y, YTD through August. That said, we are projecting a steep decline in employment over the next few quarters. Public sector employment has propped up the Alberta jobs market so far this year. Given the fiscal challenges facing the province, this is not expected to continue.
- In contrast, government coffers have felt the impact of weak oil conditions swiftly. The 2015-16Q1 Fiscal Update reported an estimated $5.9 billion deficit for fiscal 2015-16, which Minister Ceci acknowledged could swell to $6.5 billion given current oil market conditions. The government is expected to table its first budget in October and has already made a number of announcements since taking office. Of note, despite creating a royalty review commission in June, the current royalty framework will remain unchanged until January 2017.

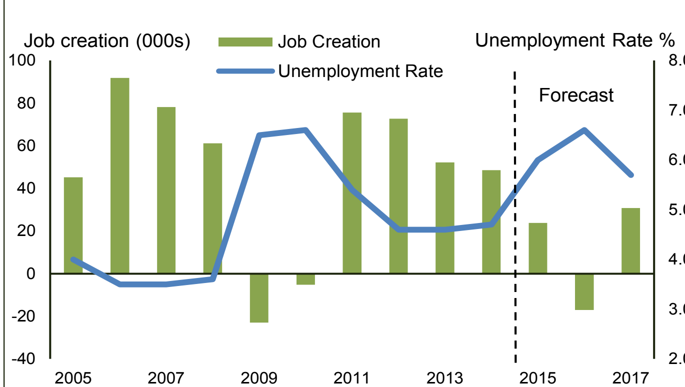
ALBERTA - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	3.8	4.5	-1.4	1.2	1.6
Nominal GDP	7.1	8.0	-8.9	4.8	5.8
Employment	2.5	2.2	1.1	-0.7	1.4
Unemployment rate (%)	4.6	4.7	6.0	6.6	5.7
Consumer Price Index	1.4	2.6	1.1	1.7	1.9
Retail trade	6.9	7.5	-3.1	1.5	3.4
Housing starts	8.2	12.5	-10.6	-9.5	-4.0
Existing home sales	9.5	8.6	-22.3	-6.8	2.1
Avg. existing home price	5.0	5.2	-2.5	-4.0	0.1

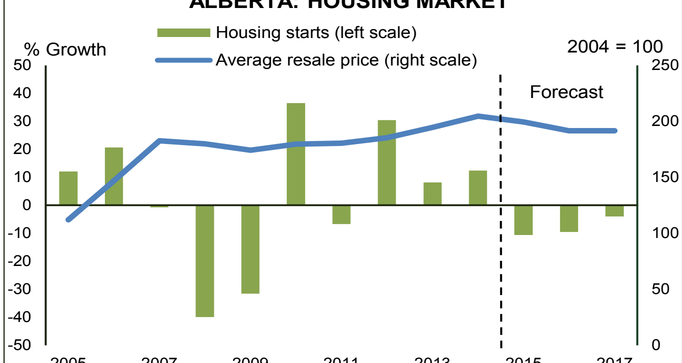
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics

ALBERTA: LABOUR MARKET PERFORMANCE



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

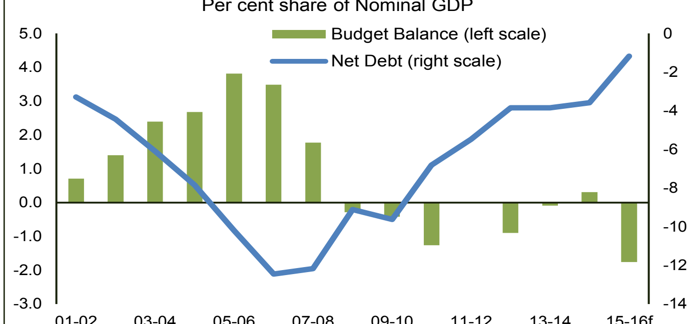
ALBERTA: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

ALBERTA: FISCAL BALANCE AND NET DEBT

Per cent share of Nominal GDP



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

SASKATCHEWAN

- The low oil price environment is expected to lead to a 0.8% contraction in Saskatchewan real GDP this year. Oil production accounts for an important 15% of real GDP and is entirely on the conventional side, which has been particularly susceptible to the low price environment. Indeed, oil production is 4% Y/Y lower in the January-July period. Engineering construction is assumed to decline in 2015, in line with lower rigging activity. Looking ahead, we expect oil production in the province to hold steady over the forecast period. Capital spending is assumed to move lower next year before stabilizing in 2017.
- The agricultural sector has offered little reprieve in 2015. Statistics Canada's estimates on crop production point to a 7% drop this year on top of last year's 21% decline, reflecting drought conditions. We expect a return to normal levels of production in 2016.
- The mining sector has been a bright spot this year. The government reports that potash production is up 15% (YTD, Y/Y) through July. Other mineral production has also increased in 2015 (+13% YTD, Y/Y), boosted by uranium output from the Cigar Lake mine. Over the forecast period, fortunes in the mining sector look set to improve. While potash prices are projected to remain weak amid rising global capacity, a healthy share of that capacity will originate from Saskatchewan. Notably, K+S's new Legacy mine is expected to start-up in 2017 and add up to 2 Mts of output when fully operational.
- The housing market is expected to undergo a correction over the 2015-16 period. Signs of extreme weakness in the housing market have already been exhibited this year, reflecting both weaker demand as well as a multi-year period of overbuilding. We expect average home prices and housing starts to move lower through 2016. In 2017, resale activity should start to improve alongside better economic fortunes. New residential construction activity will take its cue from the resale market and move higher as well.

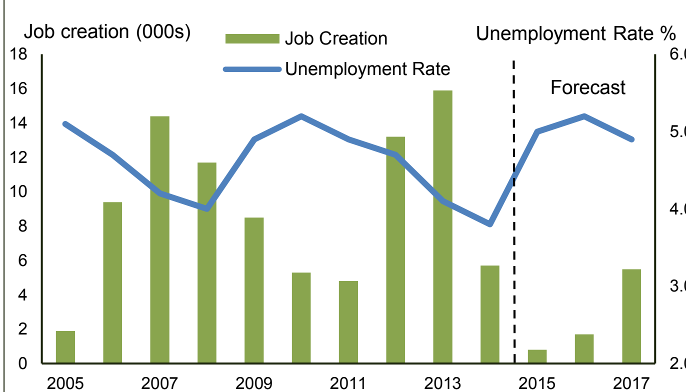
SASKATCHEWAN - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	5.0	1.5	-0.8	1.7	1.9
Nominal GDP	5.5	1.5	-4.0	4.5	4.9
Employment	3.1	1.0	0.2	0.3	1.0
Unemployment rate (%)	4.1	3.8	5.0	5.2	4.9
Consumer Price Index	1.4	2.4	1.6	1.7	1.9
Retail trade	5.1	4.6	-2.9	3.0	3.1
Housing starts	-17.1	-0.2	-27.3	-15.8	5.9
Existing home sales	-2.4	2.5	-12.4	-2.7	-0.2
Avg. existing home price	4.5	3.6	-0.6	-1.8	0.2

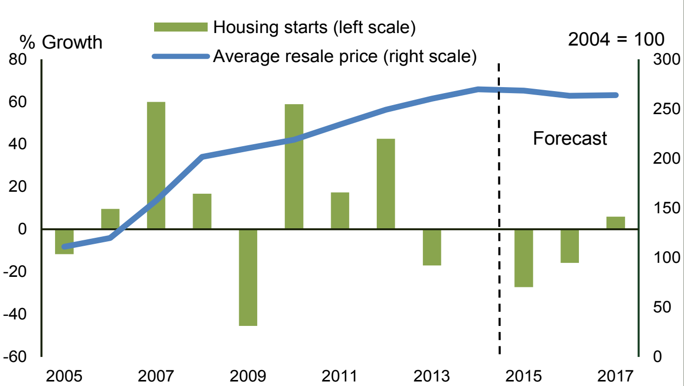
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics

SASKATCHEWAN: LABOUR MARKET PERFORMANCE



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

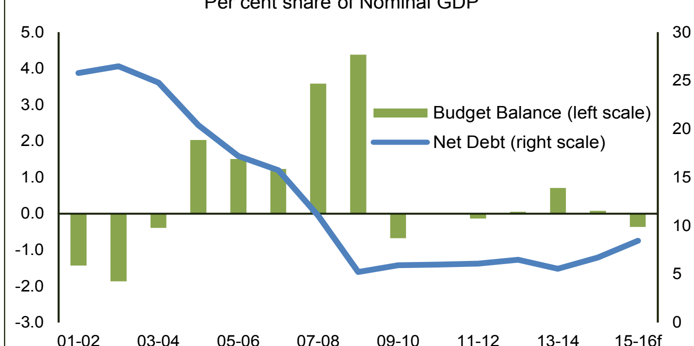
SASKATCHEWAN: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

SASKATCHEWAN: FISCAL BALANCE AND NET DEBT

Per cent share of Nominal GDP



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

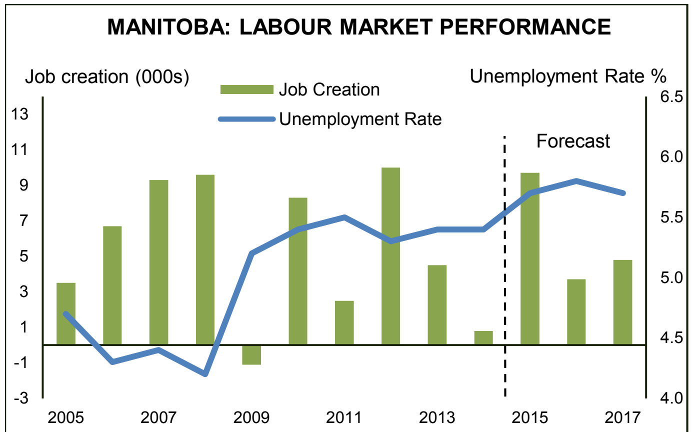
MANITOBA

- Manitoba is projected to be one of the top performing economies over the forecast period, with steady real GDP turnouts likely surpassing 2% this year and over the 2016-17 period.
- The goods sector is forecast to outperform, led by solid gains in the manufacturing, construction and agricultural sectors. While our forecast assumes only a modest increase in manufacturing activity this year, we anticipate an acceleration in output heading into 2016 tied to rising U.S. demand and a lower Canadian dollar. The transportation and warehousing and wholesale trade sectors are also well positioned to capitalize off of rising export sector activity.
- Non-residential construction is expected to remain strong, supported by the government's $5.5 billion infrastructure plan. Residential construction activity is assumed to hold steady over the forecast period, as a certain degree of overbuilding will keep new construction in check despite a projected pick up in the resale market.
- Bucking the trend of other Prairie provinces, crop production estimates point to a 12% jump in output in 2015, providing an enormous boost to the overall performance of the agricultural sector. That said, world agricultural commodity prices have been extremely soft in recent months. Looking ahead, while we expect crop prices to bottom by the end of this year, elevated stockpiles will limit the upside. In terms of domestic crop production, our forecast assumes a pullback in activity in 2016 to bring it more in line with historical trends.
- The job market has surprised on the upside this year, with employment forecast to increase 1.6% in 2015 – this fastest pace across all regions. Notable gains to date have been recorded in the construction, educational services, health care and social assistance and transportation and warehousing sectors. On the down side, growth in average weekly earnings have decelerated this year, averaging 2.3% Y/Y so far in 2015, well short of the 4.3% increase recorded in 2014. This will keep retail spending in check this year. Over the forecast period, we expect these trends to flip, with the pace of hiring slowing but wage gains to pick up modestly in line with the rising nominal GDP growth profile.

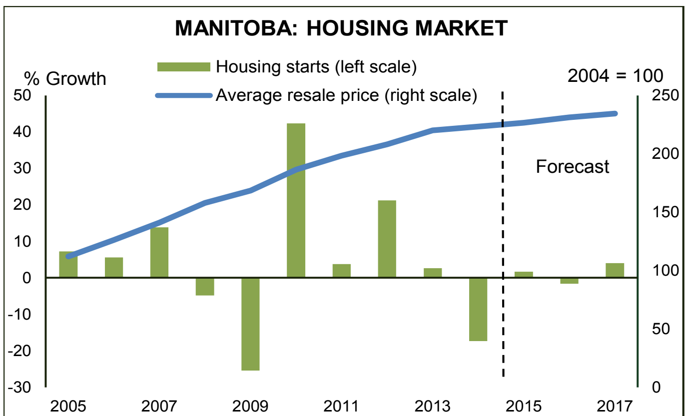
MANITOBA - TD ECONOMICS' FORECASTS
Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	2.2	1.3	2.3	2.2	2.1
Nominal GDP	3.7	3.6	3.7	4.2	4.4
Employment	0.7	0.1	1.6	0.6	0.8
Unemployment rate (%)	5.4	5.4	5.7	5.8	5.7
Consumer Price Index	2.3	1.8	1.1	2.0	2.2
Retail trade	3.9	4.3	1.0	3.4	3.4
Housing starts	2.6	-17.4	1.7	-1.6	4.0
Existing home sales	-1.2	0.3	2.8	1.0	-1.9
Avg. existing home price	5.7	1.5	1.5	2.0	1.4

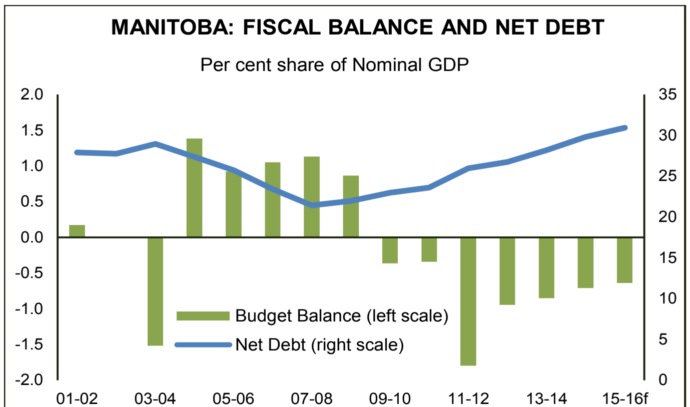
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics



Source: Haver Analytics. Forecast by TD Economics as of October 2015.



Source: Haver Analytics. Forecast by TD Economics as of October 2015.



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

ONTARIO

- Ontario's estimated growth performance this year has been marked down slightly in light of a weaker-than-expected 2015H1. Despite this setback, we still believe real GDP will rise by 2% on account of rising export activity. Positive momentum over 2015H2 should translate into a 2.4% increase in 2016 with real GDP growth projected at 2% in 2017.
- With the Canadian dollar forecast to depreciate alongside a U.S. economy tapped to average real GDP gains above 2.5% annualized over the next 6 quarters, manufacturing activity is expected to revv up. The recent announcement that the consolidated GM line will be extended until mid-2017 (previously scheduled to shut down in 2016) has provide an added fillip to factory-sector output next year. The slated closure in 2017, combined with an expected rebound in the loonie, underpins our more cautious view for factory sector output in 2017. This backdrop also sets the stage for Ontario's tourism-related industries to record solid gains. The Pan Am/ParaPan Am games will provide an added boost to activity in 2015.
- Low interest rates have added fuel to the housing market in 2015, with both resale and new construction activity coming in well ahead of our expectations. This outperformance has further increased concerns about the degree of overvaluation and overbuilding in the market. Looking ahead, with longer-term borrowing rates likely to rise gradually in 2016, we expect an orderly rebalancing to take place in the resale housing market. The recent run-up in starts will add to a large pipeline of supply, likely setting the stage for a pull-back in housing starts by more than 20% over the 2016-17 period.
- The booming housing market has delivered a shot to the arm to consumer confidence. Retail spending is forecast to clock-in at around 5% - more than twice the national rate. Looking ahead to 2016-17, a moderate pick up in job creation will continue to keep consumers spending growing at a decent clip.
- Nominal GDP growth in Ontario is expected to average 4.2% over the 2016-17 period, marking the first time it has surpassed 4% since 2011. From a fiscal perspective, this improved economic growth profile will help support revenue gains and further fiscal improvement.

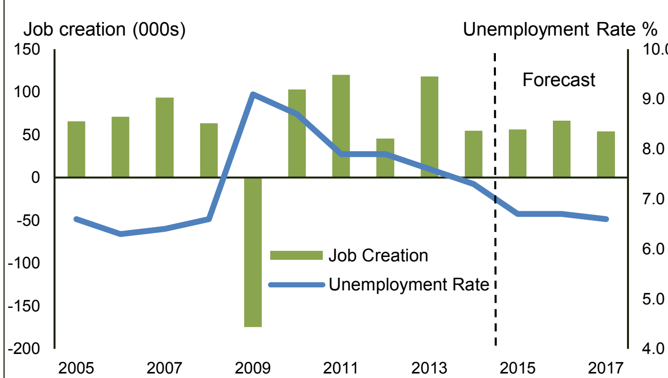
ONTARIO - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	1.3	2.2	2.0	2.4	2.0
Nominal GDP	2.4	3.6	3.5	4.4	4.0
Employment	1.8	0.8	0.8	1.0	0.8
Unemployment rate (%)	7.6	7.3	6.7	6.7	6.6
Consumer Price Index	1.1	2.3	1.3	1.9	2.1
Retail trade	2.3	5.0	4.8	3.7	3.0
Housing starts	-21.4	-4.3	9.0	-7.9	-18.5
Existing home sales	0.3	3.7	9.8	-1.4	-9.0
Avg. existing home price	5.1	7.0	7.5	1.9	-1.0

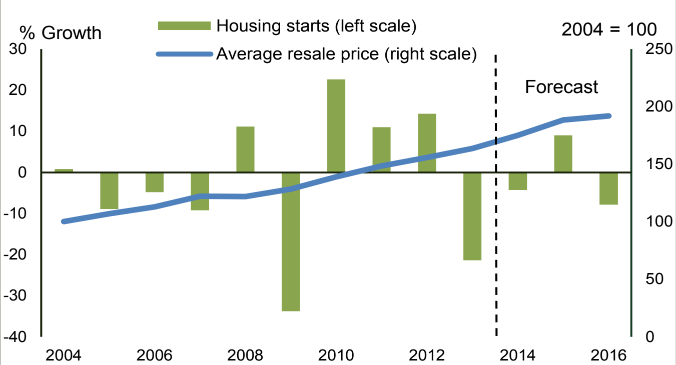
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics

ONTARIO: LABOUR MARKET PERFORMANCE



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

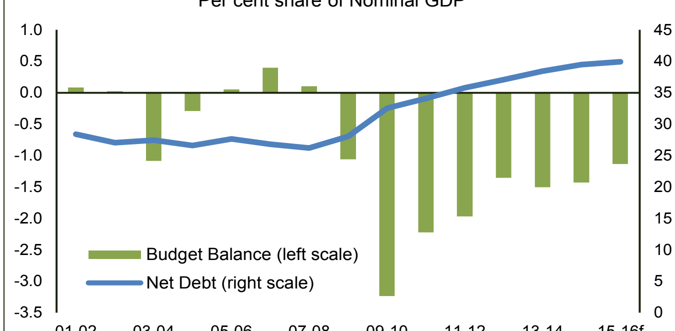
ONTARIO: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

ONTARIO: FISCAL BALANCE AND NET DEBT

Per cent share of Nominal GDP



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

QUÉBEC

- Québec's economy turned in a mixed performance in the first half of 2015, with real GDP rising by a modest 1.3% (Y/Y). A pull-back in activity in the province's construction sector has weighed on economic activity so far this year. With momentum expected to build in the near term, the pace of expansion in Québec is likely to average 1.7% this year before accelerating to roughly 2% over the 2016-17 period.
- Nominal export sales in Quebec rose a strong 9.5% Y/Y in the January- August period – bucking the national trend of softness and the second fastest rate of expansion across all regions. Aerospace and primary metal manufacturing exports (aluminum and alumina processing) have led the charge to date. Looking ahead, the export sector is projected to maintain a healthy pace of activity helped by robust growth in U.S. demand and a weaker loonie. This bodes well for Québec's manufacturing sector, with the machinery and aerospace industries expected to be top performing industries.
- The improved economic backdrop should coincide with a decent performance in the job market. Employment in Québec has rebounded smartly in 2015, up 0.9% as of August (Y/Y, YTD), stronger than the national average. Job growth has been concentrated in the services sector, with the trades and public sector accounting for much of the gain. Hiring within private services and manufacturing are expected to help drive continued advances in employment over the forecast period. The unemployment rate has bounced around the 7.4%-8% this year, as more people have been looking for work. We expect the unemployment rate to track moderately lower over the forecast period.
- The combination of low interest rates and improved economic prospects have helped kick-start a recovery in housing market activity in Québec this year, following a three year long soft landing. That said, high long term interest rates and demographic challenges will limit the bounce back in resale housing activity in the near term. New residential construction is assumed to move lower over the 2015-16 period before rising in 2017.

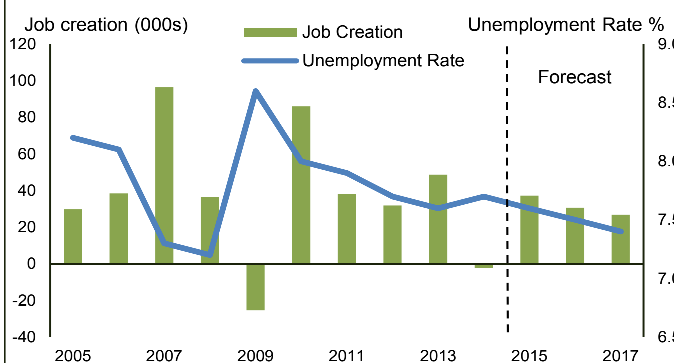
QUÉBEC - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	1.0	1.4	1.7	2.1	2.0
Nominal GDP	1.5	3.2	3.4	4.1	3.9
Employment	1.4	0.0	0.9	0.8	0.7
Unemployment rate (%)	7.6	7.7	7.6	7.5	7.4
Consumer Price Index	0.8	1.4	1.2	1.9	2.1
Retail trade	2.5	1.7	1.0	3.8	3.5
Housing starts	-20.3	3.4	-7.0	-14.4	18.1
Existing home sales	-8.0	-0.7	6.1	2.7	-0.5
Avg. existing home price	1.2	1.4	1.7	2.2	1.2

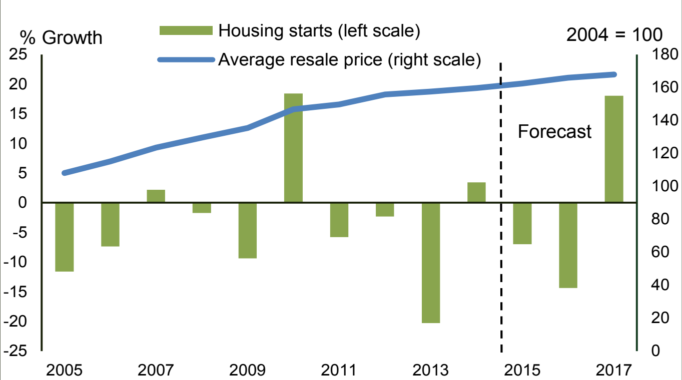
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics

QUÉBEC: LABOUR MARKET PERFORMANCE



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

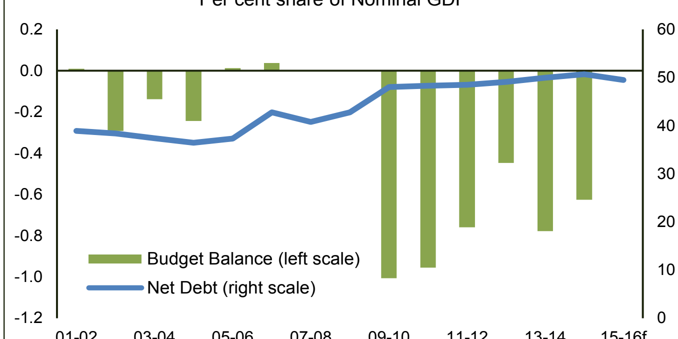
QUÉBEC: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

QUÉBEC: FISCAL BALANCE AND NET DEBT

Per cent share of Nominal GDP



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

NEW BRUNSWICK

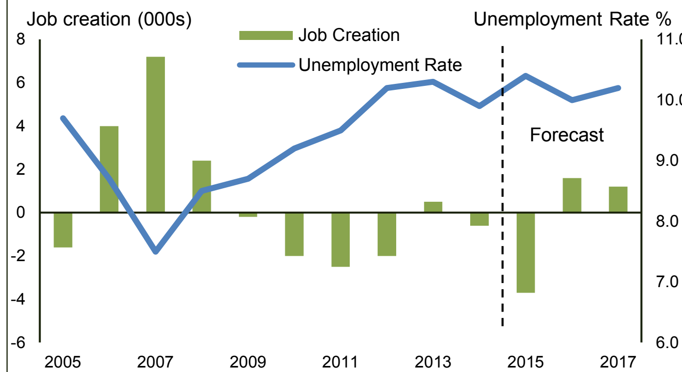
- New Brunswick's economy appears set to post stronger growth after essentially stalling over the past four years. Real GDP is forecast to rise by 1.4% in 2015, before averaging gains of 1.6% over the following two years.
- The manufacturing sector has continued to struggle in 2015 with shipments down 6.6% (Y/Y) so far this year. The weakness can be tied lower activity in the petroleum refinery industry where nominal export receipts have dropped more than 13% year-to-date. The sector will likely continue to struggle in 2015Q3, as the Irving Oil refinery is undergoing a 60-day maintenance project which will lead to output being halved to around 150K barrels per day. Looking forward, our expectation of a bounce back in refinery production, rising U.S. demand and a weaker Loonie bode well for renewed growth in manufacturing over the 2016-17 period.
- In contrast to the recent woes of the refining industry, the province's forestry sector has been enjoying robust growth. Lumber shipments shot up 17% last year and are surging again this year (up 22% YTD, Y/Y as of July). The robust showing this year can be tied to the steady rise in U.S. new residential construction activity as well as the increase in softwood fibre allocation on Crown Land dating back to last year. The forestry sector is projected to remain a top performer over the 2016-17, supported by a further recovery in homebuilding Stateside as well as higher lumber prices.
- Output in the mining sector is estimated to have increased in 2015 despite a low commodity price environment. Potash production is on track to move higher this year with the new Picadilly site coming on-line in late 2014. What's more, Trevali is currently commissioning its 3,000 tonne per day Caribou mine which is slated to provide an added boost to growth in 2016 as production is ramped up.
- Employment is set to decline 1% this year and has been struggling since the economic downturn. Weakness this year has been concentrated in the construction and wholesale and retail trade sectors. A more positive economic backdrop should translate into a modest uptick in employment – with gains around 0.4% projected over the 2016-17 period.

NEW BRUNSWICK - TD ECONOMICS' FORECASTS

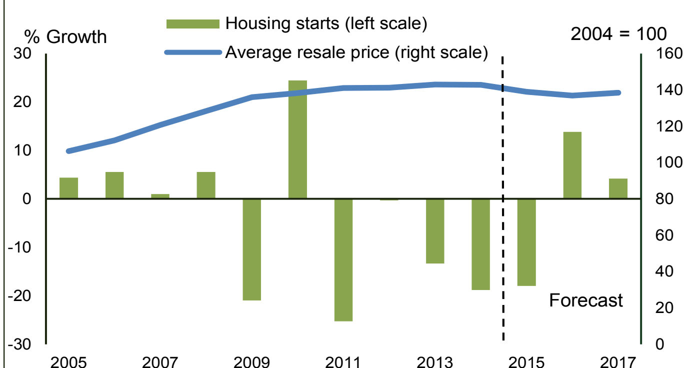
Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	-0.5	0.2	1.4	1.6	1.6
Nominal GDP	0.5	1.7	2.7	3.3	3.5
Employment	0.4	-0.2	-1.0	0.5	0.4
Unemployment rate (%)	10.3	9.9	10.4	10.0	10.2
Consumer Price Index	0.8	1.5	0.6	1.7	1.9
Retail trade	0.7	3.8	2.3	3.7	1.9
Housing starts	-13.4	-18.8	-18.0	13.8	4.2
Existing home sales	-1.9	-0.1	7.3	5.5	0.3
Avg. existing home price	1.3	-0.2	-2.6	-1.6	1.2

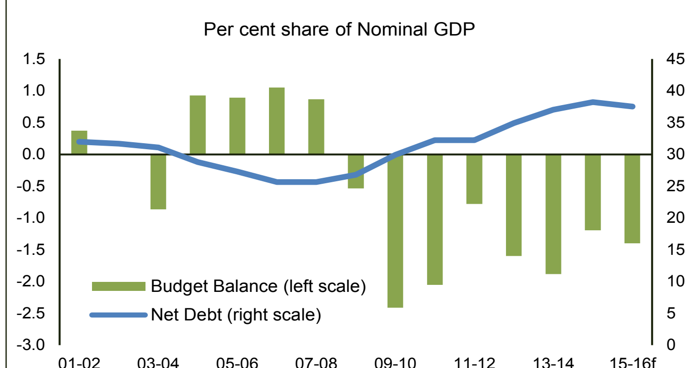
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics



Source: Haver Analytics. Forecast by TD Economics as of October 2015.



Source: Haver Analytics. Forecast by TD Economics as of October 2015.



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

NOVA SCOTIA

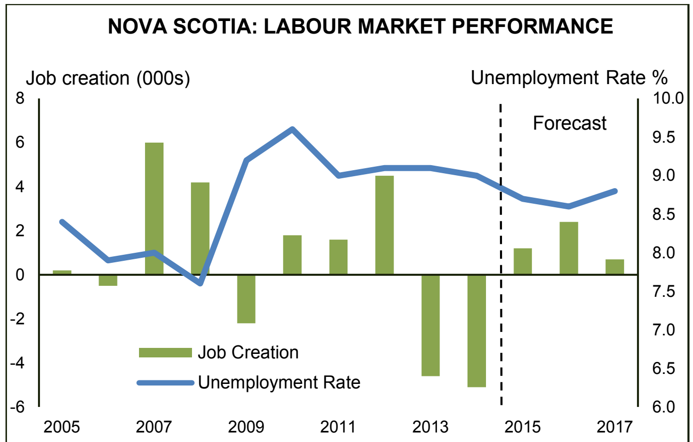
- Nova Scotia is forecast to be the top performing economy in Atlantic Canada over the forecast period. That said, average real GDP gains will remain under 2%, reflecting varying prospects across different sectors.
- The manufacturing sector is forecast to be a star performer in Nova Scotia. With the military shipbuilding project ramping up production in September, output in the transportation equipment industry will build off the solid gains recorded so far this year. A lower Canadian dollar and healthy U.S. demand augur well for other manufacturing industries such as food and tire manufacturers.
- The tourism sector also stands to benefit from this backdrop. Data in the year-to-July point to a promising turnout in in tourism-related industries. Total visitors to the province are up 5% compared to the same period last year, driven largely by road visitors from across Canada and the United States. In addition to an influx of U.S. traffic, a weaker Loonie is likely to prompt a further rise in travelers from other parts of Canada in 2016 as costs to vacation south of the border rise.
- Natural gas production is down sharply over the first half of this year (-37% YTD, Y/Y). The sharp drop reflects natural declines in output from the Sable offshore site and the Deep Panuke facility, which has transitioned to only seasonal operations. The value of natural gas exports has been further hit by weaker pricing. Looking ahead, our forecast assumes continued declines in natural gas production but a gradual turnaround in prices over the 2016-17 period.
- Despite falling production of natural gas, spending towards exploratory wells by Shell and BP will provide a boost to the sector. Shell is expected to begin drilling wells within the next few months while BP anticipates drilling in 2017.
- Construction activity has been strong in Nova Scotia this year. Several large scale projects have given non-residential investment a lift. These include the development of the Halifax shipyard as well as activity tied to the Macdonald Bridge. New residential construction has also picked up steam, mostly in the market for purpose built rentals. An aging population has driven demand for rental properties which should continue to support residential construction activity next year.

NOVA SCOTIA - TD ECONOMICS' FORECASTS

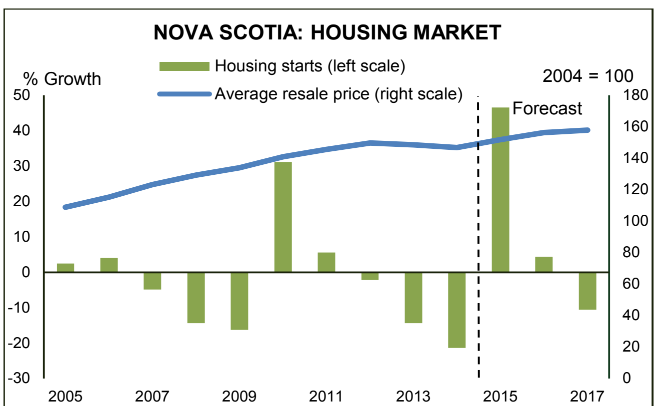
Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	0.3	1.7	1.6	2.1	1.4
Nominal GDP	2.4	3.9	2.3	4.2	3.8
Employment	-1.1	-1.1	0.3	0.6	0.2
Unemployment rate (%)	9.1	9.0	8.7	8.6	8.8
Consumer Price Index	1.2	1.7	0.5	2.0	2.0
Retail trade	2.9	2.3	-0.3	3.8	2.9
Housing starts	-14.4	-21.4	46.6	4.4	-10.6
Existing home sales	-12.4	-3.6	-14.6	1.0	2.4
Avg. existing home price	-0.9	-1.2	3.5	2.8	0.8

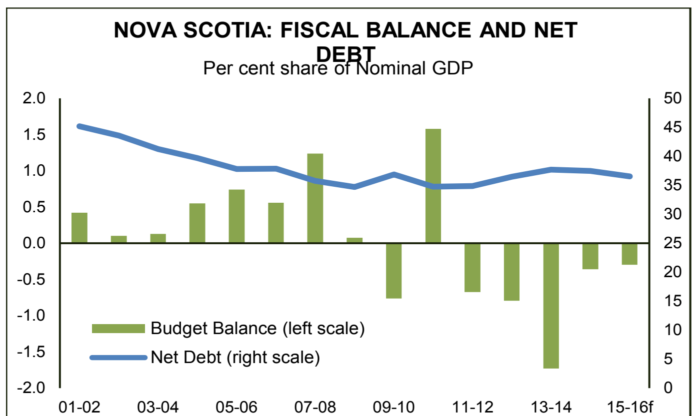
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics



Source: Haver Analytics. Forecast by TD Economics as of October 2015.



Source: Haver Analytics. Forecast by TD Economics as of October 2015.



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

PRINCE EDWARD ISLAND

- Real GDP growth in Prince Edward Island is forecast to run around 1.5% over the 2015-16 period before accelerating slightly to 1.8% in 2017.
- Nominal export receipts are tracking 18% (YTD) higher in 2015 compared to a year earlier – the strongest showing across all regions. The healthy reading reflects solid gains in the frozen food and seafood manufacturing industries. Electrical manufacturing sales have also been strong. A low Canadian dollar should support export activity over the 2016-17 period.
- The tourism sector is an important part of the P.E.I. economy. Tourism indicators have underwhelmed to date, but this likely reflects the surge in visitors tied to the Charlottetown 150th anniversary festivities last year that translate to weaker year-to-date gains so far this year. Traffic should pick up over the second half of the year. Not only will demand from the U.S. remain strong, but Canadian-based traffic should also increase on account of a lower Canadian dollar.
- The jobs market has continued to disappoint with employment set to decline for a second consecutive year. So far this year, job losses have been concentrated in the health care and social services and educational services categories. Agricultural employment has also moved lower. The one silver lining in the labour market picture this year has been wage growth. Growth in average weekly earnings (+3.8% Y/Y, YTD) has been the strongest in Canada which has helped keep retail spending in positive territory this year.
- In its June Budget, the government pushed back its balanced budget target by one year to fiscal 2016-17. The fiscal plan continues to hold the line on spending and relies on strong economic growth to help guide the Province back to balance. The rising nominal GDP growth profile assumed in our forecast will help support revenue in-take and help the government achieve its targets.

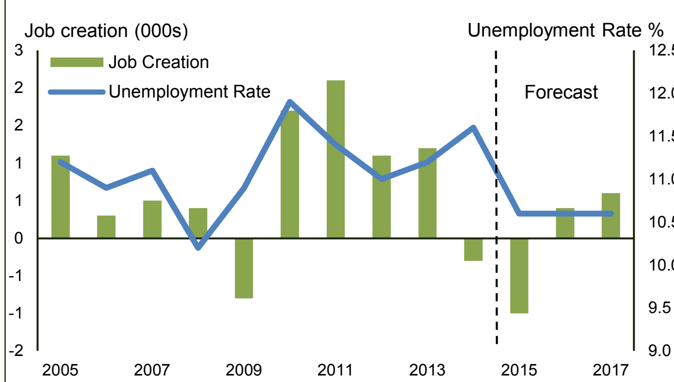
PRINCE EDWARD ISLAND - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	2.0	1.3	1.4	1.5	1.8
Nominal GDP	5.0	3.2	2.3	3.4	3.7
Employment	1.5	-0.1	-1.3	0.6	0.9
Unemployment rate (%)	11.6	10.6	10.6	10.6	10.3
Consumer Price Index	2.0	1.6	-0.4	1.9	2.0
Retail trade	0.8	3.3	2.0	3.5	3.4
Housing starts	-33.2	-18.9	-16.7	34.9	3.4
Existing home sales	-11.7	-3.2	20.3	10.9	2.4
Avg. existing home price	1.6	6.4	-1.5	-2.4	1.2

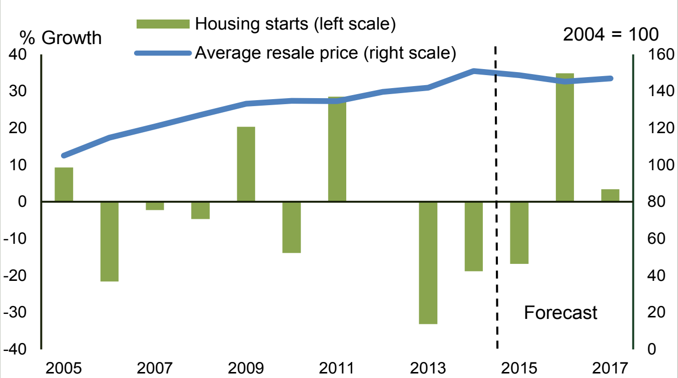
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics

P.E.I.: LABOUR MARKET PERFORMANCE



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

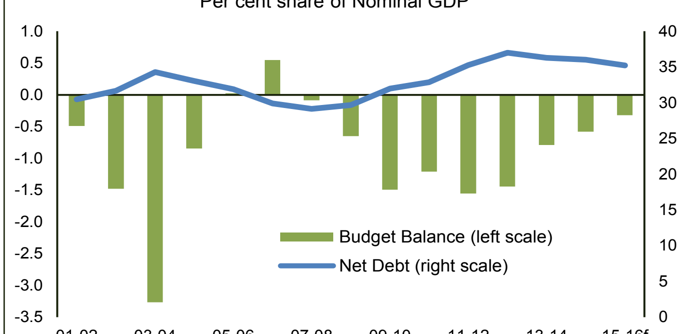
P.E.I.: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

P.E.I.: FISCAL BALANCE AND NET DEBT

Per cent share of Nominal GDP



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

NEWFOUNDLAND AND LABRADOR

- Real GDP in Newfoundland and Labrador is projected to contract over the 2015-16 period as the impact of lower commodity prices and capital spending resonates through the economy. In 2017, the economy is expected to only stabilize.
- Oil production has dropped almost 20% (Y/Y) through the first half of the year. The contraction in output reflects natural declines in production. The Terra Nova field also underwent maintenance work that affected output over the summer months. Our forecast calls for oil production to remain relatively steady over the 2016-17 period before the Hebron off shore site commences production in late 2017.
- Capital spending has been negatively impacted by the lower oil price environment with the West White Rose extension delayed. Nonetheless, investment outlays tied to the Hebron offshore oil site and Muskrat Falls will keep spending somewhat elevated in 2016 - but both projects will have already passed their peak investment years. As such, our forecast builds in average annual declines in non-residential and engineering construction of around 10% over the 2016-17 period. The near term outlook for the mining sector remains downbeat as lower iron ore prices have further delayed financing arrangements for the Alderon Kami mine which had been originally planned to already be under construction.
- Employment in Newfoundland and Labrador is expected to record the sharpest decline (-1.5%) among the provinces this year, partially reflecting weakness in the public sector. Over the 2016-17 period, we assume that employment continues to move lower. Reduced capital spending will continue to have ripple effects in the labour market over the near term while an era of fiscal restraint will cap job creation in the public sector.
- Regardless of the outcome of the election set for November 30th, the fiscal challenge facing the province is steep as oil royalty revenues account for a healthy share of revenue intake. The current government tabled its Budget in April, introducing a five-year plan to return to balance. Both expenditure restraint and revenue-raising initiatives (including a HST hike scheduled for January) were targeted to address the budget deficit.

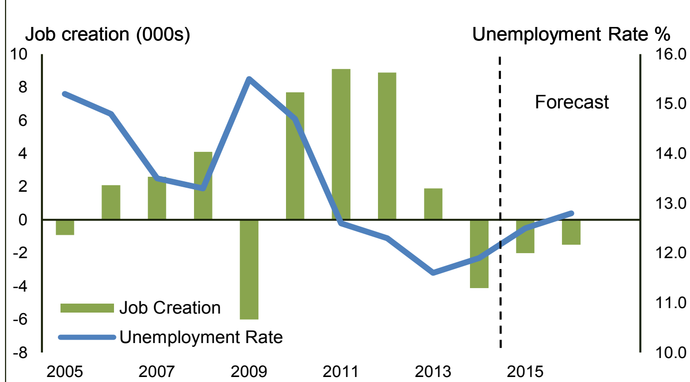
NFLD AND LABRADOR - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	7.2	-2.6	-1.9	-0.9	0.0
Nominal GDP	10.7	-2.7	-9.7	3.3	4.3
Employment	0.8	-1.7	-1.5	-0.6	-0.5
Unemployment rate (%)	11.6	11.9	12.9	13.2	13.2
Consumer Price Index	1.7	1.9	0.3	1.8	1.8
Retail trade	5.0	3.4	0.0	-1.0	0.9
Housing starts	-26.3	-22.9	-13.0	-6.8	-1.1
Existing home sales	-7.5	-4.7	0.1	-14.4	1.8
Avg. existing home price	5.4	0.2	-2.6	-7.0	-0.2

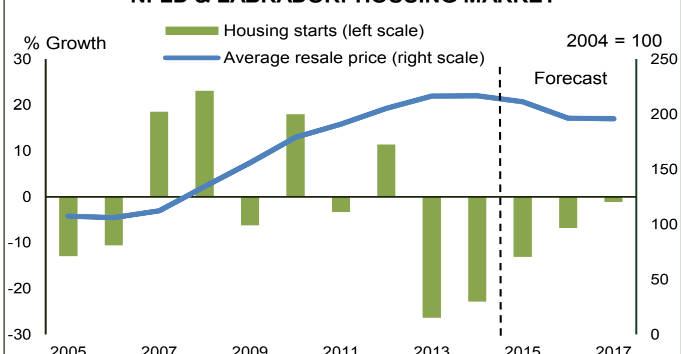
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics

NFLD & LABRADOR: LABOUR MARKET PERFORMANCE



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

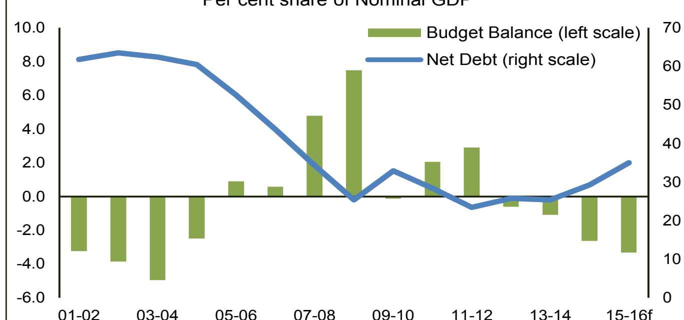
NFLD & LABRADOR: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

NFLD & LABRADOR: FISCAL BALANCE AND NET DEBT

Per cent share of Nominal GDP



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

PROVINCIAL ECONOMIC FORECASTS

REAL GROSS DOMESTIC PRODUCT (GDP) Annual average per cent change	2013	2014E	2015F	2016F	2017F
CANADA	2.0	2.4	1.2	2.0	1.9
N. & L.	7.2	-2.6	-1.9	-0.9	0.0
P.E.I.	2.0	1.3	1.4	1.5	1.8
N.S.	0.3	1.7	1.6	2.1	1.4
N.B.	-0.5	0.2	1.4	1.6	1.6
Québec	1.0	1.4	1.7	2.1	2.0
Ontario	1.3	2.2	2.0	2.4	2.0
Manitoba	2.2	1.3	2.3	2.2	2.1
Sask.	5.0	1.5	-0.8	1.7	1.9
Alberta	3.8	4.5	-1.4	1.2	1.6
B.C.	1.9	2.7	2.5	2.4	2.1

E\|F: Forecast by TD Economics as at October 2015.
Source: Statistics Canada / Haver Analytics

NOMINAL GROSS DOMESTIC PRODUCT (GDP) Annual average per cent change	2013	2014E	2015F	2016F	2017F
CANADA	3.4	4.3	0.5	4.5	4.2
N. & L.	10.7	-2.7	-9.7	3.3	4.3
P.E.I.	5.0	3.2	2.3	3.4	3.7
N.S.	2.4	3.9	2.3	4.2	3.8
N.B.	0.5	1.7	2.7	3.3	3.5
Québec	1.5	3.2	3.4	4.1	3.9
Ontario	2.4	3.6	3.5	4.4	4.0
Manitoba	3.7	3.6	3.7	4.2	4.4
Sask.	5.5	1.5	-4.0	4.5	4.9
Alberta	7.1	8.0	-8.9	4.8	5.8
B.C.	3.2	4.5	3.5	4.4	4.4

E\|F: Forecast by TD Economics as at October 2015.
Source: Statistics Canada / Haver Analytics

EMPLOYMENT Annual average per cent change	2013	2014	2015F	2016F	2017F
CANADA	1.5	0.6	0.8	0.6	0.8
N. & L.	0.8	-1.7	-1.5	-0.6	-0.5
P.E.I.	1.5	-0.1	-1.3	0.6	0.9
N.S.	-1.1	-1.1	0.3	0.6	0.2
N.B.	0.4	-0.2	-1.0	0.5	0.4
Québec	1.4	0.0	0.9	0.8	0.7
Ontario	1.8	0.8	0.8	1.0	0.8
Manitoba	0.7	0.1	1.6	0.6	0.8
Sask.	3.1	1.0	0.2	0.3	1.0
Alberta	2.5	2.2	1.1	-0.7	1.4
B.C.	0.1	0.6	0.7	1.0	0.8

E\|F: Forecast by TD Economics as at October 2015.
Source: Statistics Canada / Haver Analytics

UNEMPLOYMENT RATE Annual, per cent	2013	2014	2015F	2016F	2017F
CANADA	7.1	6.9	6.9	6.9	6.7
N. & L.	11.6	11.9	12.9	13.2	13.2
P.E.I.	11.6	10.6	10.6	10.6	10.3
N.S.	9.1	9.0	8.7	8.6	8.8
N.B.	10.3	9.9	10.4	10.0	10.2
Québec	7.6	7.7	7.6	7.5	7.4
Ontario	7.6	7.3	6.7	6.7	6.6
Manitoba	5.4	5.4	5.7	5.8	5.7
Sask.	4.1	3.8	5.0	5.2	4.9
Alberta	4.6	4.7	6.0	6.6	5.7
B.C.	6.6	6.1	5.9	5.9	5.8

E\|F: Forecast by TD Economics as at October 2015.
Source: Statistics Canada / Haver Analytics

CONSUMER PRICE INDEX (CPI) Annual average per cent change	2013	2014	2015F	2016F	2017F
CANADA	0.9	1.9	1.0	1.9	2.1
N. & L.	1.7	1.9	0.3	1.8	1.8
P.E.I.	2.0	1.6	-0.4	1.9	2.0
N.S.	1.2	1.7	0.5	2.0	2.0
N.B.	0.8	1.5	0.6	1.7	1.9
Québec	0.8	1.4	1.2	1.9	2.1
Ontario	1.1	2.3	1.3	1.9	2.1
Manitoba	2.3	1.8	1.1	2.0	2.2
Sask.	1.4	2.4	1.6	1.7	1.9
Alberta	1.4	2.6	1.1	1.7	1.9
B.C.	-0.1	1.0	1.1	2.0	2.1

E\|F: Forecast by TD Economics as at October 2015.
Source: Statistics Canada / Haver Analytics

RETAIL TRADE Annual average per cent change	2013	2014	2015F	2016F	2017F
CANADA	3.2	4.6	2.3	3.4	3.2
N. & L.	5.0	3.4	0.0	-1.0	0.9
P.E.I.	0.8	3.3	2.0	3.5	3.4
N.S.	2.9	2.3	-0.3	3.8	2.9
N.B.	0.7	3.8	2.3	3.7	1.9
Québec	2.5	1.7	1.0	3.8	3.5
Ontario	2.3	5.0	4.8	3.7	3.0
Manitoba	3.9	4.3	1.0	3.4	3.4
Sask.	5.1	4.6	-2.9	3.0	3.1
Alberta	6.9	7.5	-3.1	1.5	3.4
B.C.	2.4	5.6	7.5	4.1	2.9

E\|F: Forecast by TD Economics as at October 2015.
Source: Statistics Canada / Haver Analytics

HOUSING STARTS Thousands of units	2013	2014	2015F	2016F	2017F
CANADA	187.9	188.6	189.5	171.4	163.1
N. & L.	2.9	2.2	1.9	1.8	1.8
P.E.I.	0.6	0.5	0.4	0.6	0.6
N.S.	3.9	3.1	4.5	4.7	4.2
N.B.	2.8	2.3	1.9	2.1	2.2
Québec	37.6	38.9	36.2	31.0	36.6
Ontario	60.9	58.3	63.5	58.5	47.7
Manitoba	7.5	6.2	6.3	6.2	6.5
Sask.	8.3	8.2	6.0	5.1	5.4
Alberta	36.1	40.5	36.3	32.8	31.5
B.C.	27.1	28.3	32.5	28.7	26.7

F: Forecast by TD Economics as at October 2015.
Source: CMHC / Haver Analytics

HOUSING STARTS Per cent change	2013	2014	2015F	2016F	2017F
CANADA	-12.5	0.3	0.5	-9.6	-4.8
N. & L.	-26.3	-22.9	-13.0	-6.8	-1.1
P.E.I.	-33.2	-18.9	-16.7	34.9	3.4
N.S.	-14.4	-21.4	46.6	4.4	-10.6
N.B.	-13.4	-18.8	-18.0	13.8	4.2
Québec	-20.3	3.4	-7.0	-14.4	18.1
Ontario	-21.4	-4.3	9.0	-7.9	-18.5
Manitoba	2.6	-17.4	1.7	-1.6	4.0
Sask.	-17.1	-0.2	-27.3	-15.8	5.9
Alberta	8.2	12.5	-10.6	-9.5	-4.0
B.C.	-1.5	4.6	14.9	-11.9	-6.8

F: Forecast by TD Economics as at October 2015.
Source: CMHC / Haver Analytics

EXISTING HOME SALES Thousands of units	2013	2014	2015F	2016F	2017F
CANADA	457.6	481.2	503.0	489.6	457.3
N. & L.	4.3	4.1	4.1	3.5	3.6
P.E.I.	1.4	1.4	1.7	1.8	1.9
N.S.	9.2	8.8	7.5	7.6	7.8
N.B.	6.3	6.3	6.7	7.1	7.1
Québec	71.2	70.7	75.0	77.0	76.7
Ontario	197.4	204.7	224.7	221.5	201.5
Manitoba	13.7	13.8	14.2	14.3	14.1
Sask.	13.5	13.9	12.2	11.8	11.8
Alberta	66.1	71.8	55.8	52.0	53.0
B.C.	72.9	84.0	100.3	92.9	79.8

F: Forecast by TD Economics as at October 2015.
Source: Canadian Real Estate Association

EXISTING HOME SALES Per cent change	2013	2014	2015F	2016F	2017F
CANADA	0.7	5.1	4.5	-2.7	-6.6
N. & L.	-7.5	-4.7	0.1	-14.4	1.8
P.E.I.	-11.7	-3.2	20.3	10.9	2.4
N.S.	-12.4	-3.6	-14.6	1.0	2.4
N.B.	-1.9	-0.1	7.3	5.5	0.3
Québec	-8.0	-0.7	6.1	2.7	-0.5
Ontario	0.3	3.7	9.8	-1.4	-9.0
Manitoba	-1.2	0.3	2.8	1.0	-1.9
Sask.	-2.4	2.5	-12.4	-2.7	-0.2
Alberta	9.5	8.6	-22.3	-6.8	2.1
B.C.	7.8	15.2	19.3	-7.4	-14.1

F: Forecast by TD Economics as at October 2015.
Source: Canadian Real Estate Association

AVERAGE EXISTING HOME PRICE Thousands of C$	2013	2014	2015F	2016F	2017F
CANADA	381.7	407.0	436.3	440.9	431.1
N. & L.	283.7	284.3	276.9	257.5	256.8
P.E.I.	155.1	165.1	162.6	158.7	160.6
N.S.	216.3	213.7	221.1	227.4	229.2
N.B.	161.4	161.1	156.9	154.4	156.2
Québec	267.7	271.4	276.0	282.2	285.4
Ontario	401.2	429.2	461.2	469.8	465.2
Manitoba	260.7	264.7	268.6	273.9	277.8
Sask.	287.5	297.9	296.3	290.8	291.5
Alberta	380.2	399.8	390.0	374.2	374.4
B.C.	537.6	570.2	628.8	655.0	647.0

F: Forecast by TD Economics as at October 2015.
Source: Canadian Real Estate Association

AVERAGE EXISTING HOME PRICE Per cent change	2013	2014	2015F	2016F	2017F
CANADA	5.6	6.6	7.2	1.0	-2.2
N. & L.	5.4	0.2	-2.6	-7.0	-0.2
P.E.I.	1.6	6.4	-1.5	-2.4	1.2
N.S.	-0.9	-1.2	3.5	2.8	0.8
N.B.	1.3	-0.2	-2.6	-1.6	1.2
Québec	1.2	1.4	1.7	2.2	1.2
Ontario	5.1	7.0	7.5	1.9	-1.0
Manitoba	5.7	1.5	1.5	2.0	1.4
Sask.	4.5	3.6	-0.6	-1.8	0.2
Alberta	5.0	5.2	-2.5	-4.0	0.1
B.C.	4.8	6.1	10.3	4.2	-1.2

F: Forecast by TD Economics as at October 2015.
Source: Canadian Real Estate Association

HOUSING MARKET INFORMATION

HOUSING NOW
BC Region

CANADA MORTGAGE AND HOUSING CORPORATION

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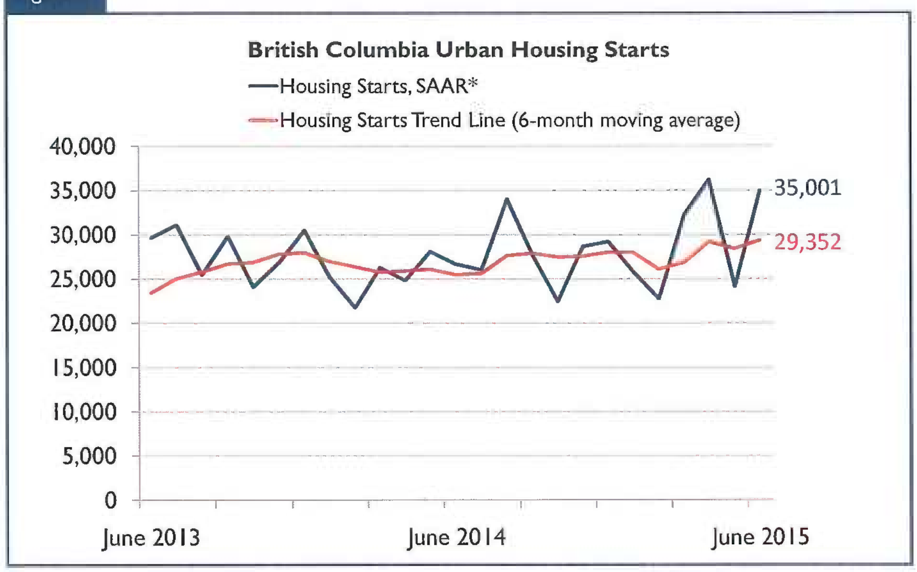
New Home Market

Housing starts in British Columbia's urban centres[1] were trending at 29,352 units in June compared to 28,384 units in May, according to Canada Mortgage and Housing Corporation (CMHC). The trend is a six-month moving average of the monthly seasonally-adjusted annual rates (SAAR)[2] of housing starts (see Figure 1).

Robust new residential construction reflects demand for housing stemming from population growth and an active resale market. As well, inventories of completed and unabsorbed new

Figure 1



Source: CMHC Starts and Completions Survey

[1] Urban Centres are centres with populations of 10,000 or more people.

[2] Seasonally adjusted annual rates (SAAR) – Monthly housing starts figures are adjusted to remove normal seasonal variation and multiplied by 12 to reflect annual levels. By removing seasonal ups and downs, seasonal adjustment allows for a comparison from one season to the next and from one month to the next. Reporting monthly figures at annual rates indicates the annual level of starts that would be obtained if the monthly pace was maintained for 12 months. This facilitates comparison of the current pace of activity to annual forecasts as well as to historical annual levels.

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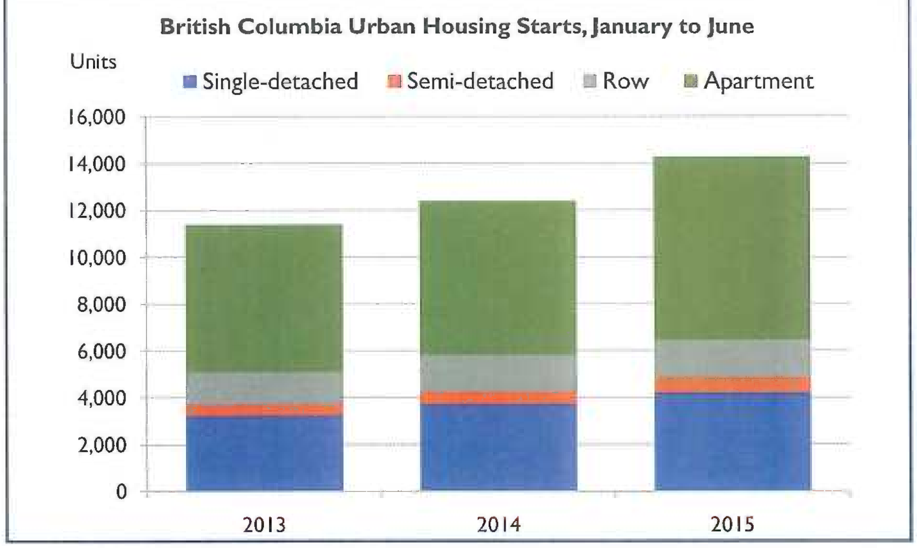
housing have been trending lower as demand for new homes exceeds completions. Actual housing starts in British Columbia's urban centres totalled 8,121 units in the second quarter of 2015 compared to 6,836 units in the second quarter of 2014. All home types, with the exception of townhomes, recorded higher starts compared to year-earlier levels. A total of 14,286 homes were started during the first half of 2015, representing a 15.2 per cent increase compared to the first half of 2014 (see Figure 2).

So far in 2015, builders have responded to demand for ground-oriented homes with increased housing starts, a trend carried over from 2014. As well, a rebound in multiple-unit housing starts reflects a combination of rental and homeownership units getting underway. More than 2,300 rental units were started during the first half of 2015 compared to fewer than 1,800 rental units started during the first half of 2014. This result can be attributed to a number of purpose-built rental projects in centres where April 2015 apartment vacancy rates were less than two per cent (Victoria, Vancouver, Courtenay, Penticton) and in Nanaimo where new rental projects have been in demand. Freehold and condominium apartment starts totalled 5,466 units compared to 4,805 starts in the first half of 2014 (Table 2.3).

Levels of new residential construction were generally higher in 2015 compared to 2014 in the province's urban centres with populations of 50,000 or more, while some smaller centres recorded lower levels of housing starts compared to the first half of last year.

Figure 2



Source: CMHC Starts and Completions Survey

Among the CMAs, Victoria posted the largest increase (65 per cent) with a rebound in housing starts across all dwelling types but mostly driven by a rebound in apartment starts. Vancouver posted the largest increase in absolute terms (up 833 units to 9,938 starts), similarly driven by an increase in apartment starts. Vancouver also recorded a higher number of single-detached starts; however fewer townhomes got underway compared to the first half of 2014. The level of starts was modestly higher in Abbotsford-Mission and in Kelowna.

Similar to the CMAs, notable increases were recorded in several centres with population of 50,000 to 99,999 people. Year-to-date starts were double the level recorded during the first half of 2014 in Courtenay and Prince George and almost double in Nanaimo. Kamloops was the only centre of this size where housing starts were lower compared to the first half of 2014, mainly due to a pullback in apartment starts; single-detached, semi-detached and townhome starts in Kamloops were up from the previous year as demand shifted to ground-oriented home types.

Urban centres with populations between 10,000 and 49,999 posted mixed results. In Fort St. John, 100 townhomes were started in the second quarter, boosting the year-to-date total to 250 units compared to 66 housing starts in the first half of 2014. Dawson Creek saw a pull-back in housing starts in the second quarter, as did Campbell River, Cranbrook, Salmon Arm and Terrace.

In the rural centres of the province, which have less than 10,000 people, fewer new homes got underway this year compared to last year. In these rural centres, starts were estimated at 385 housing starts in the second quarter of 2015, compared to 440 housing starts in the same quarter of 2014, bringing the total year-to-date starts to slightly below their 2014 first half level.

The level of completed and unabsorbed (unsold) new homes in British Columbia's CMAs and Census Agglomerations (CAs) with 50,000 or more people has been trending lower across all home types (see Figure 3). In June 2015, there were 3,552 new homes completed and unabsorbed (unsold), down from 6,638 a year earlier, with inventories of new apartments and new single-detached homes declining.

Resale Market

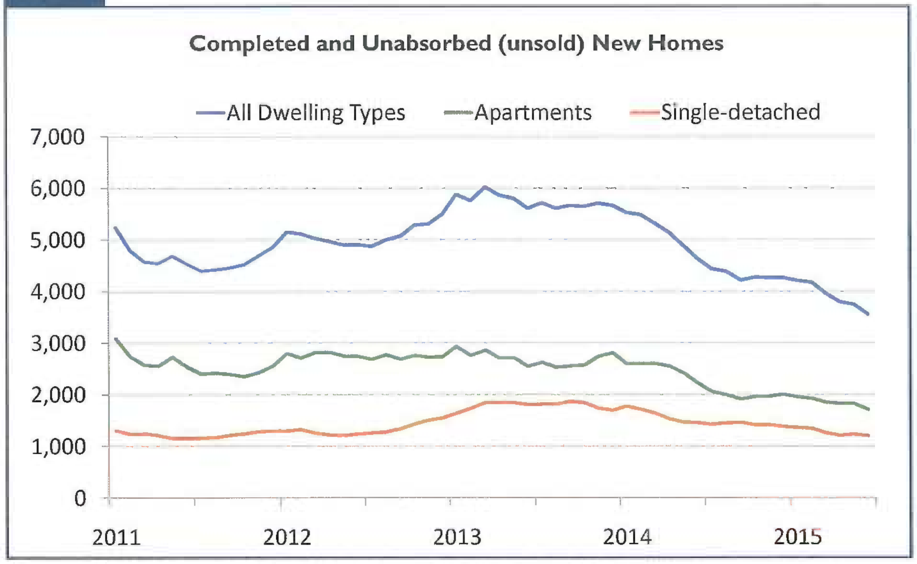
Provincial resale market conditions moved into sellers' market territory in 2015, according to the MLS® sales-to-new listings ratio; however some local markets may still be in balanced market conditions if new listings have kept pace with resales. Conditions may also vary by home type. In some local markets, including Vancouver and the Fraser Valley, ground-oriented homes have recorded stronger demand than available supply. On a seasonally-adjusted basis, the sales-to-new listings ratio for British Columbia increased to 67.5 per cent in the second quarter, compared to 60.3 per cent in the first quarter, a level that is estimated to be consistent with sellers' resale market conditions.

Resales are up in most local markets, driving the provincial total higher (see Figure 4). The pace of sales activity increased in the second quarter of 2015, with 101,880 resale transactions at a seasonally-adjusted annual rate (SAAR) compared to 94,064 SAAR in the first quarter. The ten-year average for British Columbia is about 84,800 transactions. Meanwhile, the level of new listings slowed to 150,844 SAAR in the second quarter compared to 155,904 SAAR in the first quarter.

The average home price has been influenced by compositional changes during the past few years. In the second quarter of 2015 this may be a smaller influence on the provincial price since the Vancouver share of home sales was lower in the second quarter compared to the first quarter, accounting for 42 per cent of provincial sales (down from 43 per cent). The British Columbia average MLS® price was $632,914 in the second quarter, up 12.8 per cent from the year-earlier levels, a faster pace of annual increase than recorded in the second quarter of 2014 (5.5 per cent).

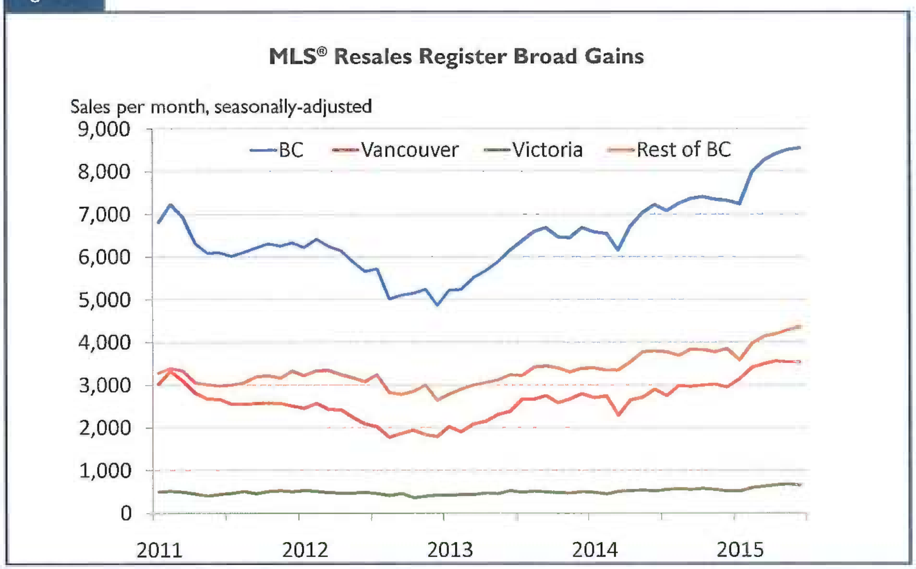
The CREA house price index, a measure of price change designed to better reflect market price growth, was up 10.3 per cent in June 2015

Figure 3



Source: CMHC Starts and Completions Survey, for BC Census Metropolitan Areas and Census Agglomerations with at least 50,000 people.

Figure 4



Sources: CREA, CMHC calculation

compared to June 2014 in the Greater Vancouver board area. According to this measure, price gains in other board areas have been more moderate: up 4.3 per cent year-over-year in Victoria and up 4.6 per cent year-over-year in the Fraser Valley.

Economic Trends

Mortgage interest rates remain low and relatively stable across Canada. A 25 basis point decline in the Bank of Canada's target overnight rate during the first quarter of 2015 translated into slightly lower short-term mortgage interest rates. The one-year posted mortgage rate was 2.9 per cent compared to 3.1 per cent a year earlier. The five-year posted mortgage rate was 4.6 per cent in the second quarter compared to 4.8 per cent in the previous four quarters. As a result of these interest rate developments, the principal plus interest on a $100,000 mortgage[3] was $561 per month in the second quarter of 2015, down from $570 per month in the second quarter of 2014.

Labour market conditions have improved but remain tepid, with year-to-date employment growth at 0.4 per cent. Employment levels have fluctuated on a month-to-month basis; however, in the second quarter, solid gains were recorded in May and June, following a decline in April. As a result, June's level of employment reached a new high. While the year-to-date increase in people employed is small in magnitude, the underlying shift from part-time to full-time jobs provides a more solid foundation for housing demand.

Improving job markets are one factor attracting people to British Columbia from other parts of Canada. With employment growth outpacing growth in the labour force, the unemployment rate declined steadily during the second quarter and was 5.8 per cent in June, from 6.3 per cent in April. This level is only slightly higher than Alberta's 5.7 per cent and below Ontario's 6.5 per cent.

Labour market conditions have been generally supportive of housing demand, but more recently stronger-than-expected gains in net interprovincial migration (people moving to the province from the rest of Canada) is contributing to housing demand. In the first quarter of 2015, British Columbia recorded a net interprovincial inflow of 3,806 people[4], including more than 1,000 from Alberta, and about 900 from Ontario. This represented the fifth consecutive quarterly net gain from other provinces. However, on the international front, British Columbia gained an estimated 2,315 people from other countries during the first quarter of 2015, a historically low net international figure. This was mostly the result of a lower level of immigration and a net loss of non-permanent residents.

Residential building permits issued by municipalities are closely related to new home construction, although not every permit becomes a housing start. The value of residential building permits[5] issued by municipalities in BC in April and May was up 31.5 per cent from year-earlier levels. In terms of the number of units represented by permits issued, the level of potential new residential construction has increased. During the twelve months to May 2015 (latest data available), the number of units totalled 31,787 compared to 27,616 in the previous twelve month period.

[3] Principal and interest assumes $100,000 mortgage amortized over 25 years using current 5 year interest rate.

[4,5] Statistics Canada

HOUSING NOW REPORT TABLES

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4.1	Average Price ($) of Absorbed Single-Detached Units

SYMBOLS

n/a	Not applicable
*	Totals may not add up due to co-operatives and unknown market types
**	Percent change > 200%
-	Nil
--	Amount too small to be expressed
SA	Monthly figures are adjusted to remove normal seasonal variation

Table 1: Housing Starts (SAAR and Trend) June 2015		
British Columbia	May 2015	June 2015
Trend[1], urban centres[2]	28,384	29,352
SAAR, urban centres[2]	24,113	35,001
	June 2014	June 2015
Actual, urban centres[2]		
June - Single-Detached	760	853
June - Multiples	1,564	2,157
June - Total	2,324	3,010
January to June - Single-Detached	3,702	4,196
January to June - Multiples	8,694	10,090
January to June - Total	12,396	14,286

Source: CMHC

[1] The trend is a six-month moving average of the monthly seasonally adjusted annual rates (SAAR)

[2] Urban centres with a population of 10,000 and over.

Detailed data available upon request

Effective January 2013, single-detached houses with an attached accessory suite are recorded as one unit "Ownership, Single" and the accessory suite as one unit "Rental, Apt + Other". In 2012 and prior years, these structures were recorded as two units, "Ownership, Freehold, Apt + Other" in some markets, including the Vancouver CMA and Abbotsford-Mission CMA. This adjustment provides national consistency.

Table 1.1: Housing Activity Summary of British Columbia Region Second Quarter 2015										
	Urban Centres								Rural Centres	Total*
	Ownership						Rental			
	Freehold			Condominium						
	Single	Semi	Row, Apt. & Other	Single	Row and Semi	Apt. & Other	Single, Semi, and Row	Apt. & Other		
STARTS										
Q2 2015	2,189	230	11	85	924	2,988	164	1,530	385	8,506
Q2 2014	1,978	246	102	21	933	2,473	175	908	440	7,276
% Change	10.7	-6.5	-89.2	**	-1.0	20.8	-6.3	68.5	-12.5	16.9
Year-to-date 2015	3,777	400	19	123	1,832	5,466	306	2,363	602	14,888
Year-to-date 2014	3,335	406	102	67	1,705	4,703	300	1,778	610	13,006
% Change	13.3	-1.5	-81.4	83.6	7.4	16.2	2.0	32.9	-1.3	14.5
UNDER CONSTRUCTION										
Q2 2015	6,384	631	23	147	3,263	18,026	501	5,177	1,410	35,562
Q2 2014	5,590	671	13	99	3,067	17,016	434	4,043	1,390	32,323
% Change	14.2	-6.0	76.9	48.5	6.4	5.9	15.4	28.0	1.4	10.0
COMPLETIONS										
Q2 2015	1,889	206	0	74	947	2,411	138	921	299	6,885
Q2 2014	1,638	172	20	14	849	1,446	182	850	282	5,453
% Change	15.3	19.8	-100.0	**	11.5	66.7	-24.2	8.4	6.0	26.3
Year-to-date 2015	3,459	432	0	126	1,743	4,014	299	1,625	724	12,422
Year-to-date 2014	3,288	414	38	30	1,454	3,933	355	1,678	564	11,754
% Change	5.2	4.3	-100.0	**	19.9	2.1	-15.8	-3.2	28.4	5.7
COMPLETED & NOT ABSORBED										
Q2 2015	1,150	135	0	48	511	1,708	n/a	n/a	n/a	3,552
Q2 2014	1,437	135	14	18	804	2,230	n/a	n/a	n/a	4,638
% Change	-20.0	0.0	-100.0	166.7	-36.4	-23.4	n/a	n/a	n/a	-23.4
ABSORBED										
Q2 2015	1,723	175	0	54	1,121	2,519	n/a	n/a	n/a	5,592
Q2 2014	1,563	157	19	19	879	1,817	n/a	n/a	n/a	4,454
% Change	10.2	11.5	-100.0	184.2	27.5	38.6	n/a	n/a	n/a	25.6
Year-to-date 2015	3,145	334	0	101	1,853	4,215	n/a	n/a	n/a	9,648
Year-to-date 2014	3,108	376	44	34	1,516	4,342	n/a	n/a	n/a	9,420
% Change	1.2	-11.2	-100.0	197.1	22.2	-2.9	n/a	n/a	n/a	2.4

Source: CMHC (Starts and Completions Survey, Market Absorption Survey)

Effective January 2013, single-detached houses with an attached accessory suite are recorded as one unit "Ownership, Single" and the accessory suite as one unit "Rental, Apt + Other". In 2012 and prior years, these structures were recorded as two units, "Ownership, Freehold, Apt + Other" in some markets, including the Vancouver CMA and Abbotsford-Mission CMA. This adjustment provides national consistency.

Table 1.3: History of Housing Starts of British Columbia Region 2005 - 2014										
	Urban Centres								Rural Centres	Total*
	Ownership						Rental			
	Freehold			Condominium						
	Single	Semi	Row, Apt. & Other	Single	Row and Semi	Apt. & Other	Single, Semi, and Row	Apt. & Other		
2014	7,559	931	106	171	3,751	9,630	679	3,884	1,615	28,356
% Change	16.1	11.5	**	71.0	16.1	-8.9	2.7	3.5	18.0	4.8
2013	6,513	835	22	100	3,231	10,572	661	3,751	1,369	27,054
% Change	6.3	16.1	-99.1	13.6	1.0	0.6	26.6	104.4	-31.1	-1.5
2012	6,129	719	2,476	88	3,198	10,510	522	1,835	1,988	27,465
% Change	-6.6	6.4	6.5	-29.6	-15.5	28.5	4.0	-16.4	-3.2	4.0
2011	6,559	676	2,325	125	3,783	8,181	502	2,195	2,054	26,400
% Change	-24.8	0.7	59.4	-36.5	15.4	16.4	-40.6	57.1	-28.7	-0.3
2010	8,723	671	1,459	197	3,277	7,031	845	1,397	2,879	26,479
% Change	46.9	40.4	93.5	58.9	41.8	119.7	109.7	126.4	28.3	64.7
2009	5,940	478	754	124	2,311	3,201	403	617	2,244	16,077
% Change	-26.3	-35.1	-8.4	-51.4	-47.3	-78.9	-6.1	-34.3	-35.2	-53.2
2008	8,060	737	823	255	4,383	15,206	429	939	3,464	34,321
% Change	-18.8	2.8	34.0	-41.5	-6.4	-8.7	-15.9	15.1	-28.3	-12.4
2007	9,925	717	614	436	4,681	16,663	510	816	4,833	39,195
% Change	-13.4	2.7	68.2	-13.0	-10.2	25.5	24.1	30.4	24.8	7.6
2006	11,466	698	365	501	5,211	13,279	411	626	3,872	36,443
% Change	6.8	-4.1	-15.1	5.9	4.4	7.0	31.3	-39.7	9.1	5.1
2005	10,732	728	430	473	4,993	12,411	313	1,039	3,548	34,667

Source: CMHC (Starts and Completions Survey)

Effective January 2013, single-detached houses with an attached accessory suite are recorded as one unit "Ownership, Single" and the accessory suite as one unit "Rental, Apt + Other". In 2012 and prior years, these structures were recorded as two units, "Ownership, Freehold, Apt + Other" in some markets, including the Vancouver CMA and Abbotsford-Mission CMA. This adjustment provides national consistency.

Table 2: Starts by Submarket and by Dwelling Type British Columbia Region Second Quarter 2015											
Submarket	Single		Semi		Row		Apt. & Other		Total		
	Q2 2015	Q2 2014	Q2 2015	Q2 2014	Q2 2015	Q2 2014	Q2 2015	Q2 2014	Q2 2015	Q2 2014	% Change
Centres 100,000+											
Abbotsford-Mission	91	53	4	0	0	0	26	154	121	207	-41.5
Kelowna	155	169	66	40	10	48	107	79	338	336	0.6
Vancouver	1,300	1,147	112	110	565	665	3,678	2,810	5,655	4,732	19.5
Victoria	159	145	26	12	26	11	297	237	508	405	25.4
Centres 50,000 - 99,999											
Chilliwack	96	65	10	12	33	52	109	44	248	173	43.4
Courtenay	44	37	16	14	8	4	7	6	75	61	23.0
Kamloops	96	89	18	16	19	4	22	4	155	113	37.2
Nanaimo	105	105	8	4	31	7	191	41	335	157	113.4
Prince George	47	36	6	2	10	0	47	3	110	41	168.3
Vernon	54	42	10	4	3	18	2	1	69	65	6.2
Centres 10,000 - 49,999											
Campbell River	22	41	6	12	0	0	1	0	29	53	-45.3
Cranbrook	17	27	0	0	0	0	0	0	17	27	-37.0
Dawson Creek	11	8	4	58	4	33	9	26	28	125	-77.6
Duncan	42	42	0	0	0	0	11	17	53	59	-10.2
Fort St. John	42	22	20	16	100	0	1	0	163	38	**
Nelson[1]	2	2	0	2	0	0	0	0	2	4	-50.0
Parksville-Qualicum Beach	31	22	2	8	6	4	0	0	39	34	14.7
Penticton	39	46	12	2	8	0	5	6	64	54	18.5
Port Alberni	7	10	0	0	0	0	0	0	7	10	-30.0
Powell River	0	4	0	0	0	0	0	0	0	4	-100.0
Prince Rupert	4	1	2	0	0	0	0	0	6	1	**
Quesnel	4	7	0	0	0	0	0	0	4	7	-42.9
Salmon Arm	18	14	0	0	3	9	0	25	21	48	-56.3
Salt Spring Island[1]	2	0	0	0	0	0	0	0	2	0	n/a
Squamish	22	13	2	12	9	0	4	2	37	27	37.0
Summerland	4	3	0	0	0	0	0	0	4	3	33.3
Terrace	11	15	2	0	12	0	1	28	26	43	-39.5
Williams Lake	5	9	0	0	0	0	0	0	5	9	-44.4
Total British Columbia (10,000+)	2,430	2,174	326	324	847	855	4,518	3,483	8,121	6,836	18.8

Source: CMHC (Starts and Completions Survey)
[1]This centre is new to our survey as of 2013

Effective January 2013, single-detached houses with an attached accessory suite are recorded as one unit "Ownership, Single" and the accessory suite as one unit "Rental, Apt + Other". In 2012 and prior years, these structures were recorded as two units, "Ownership, Freehold, Apt + Other" in some markets, including the Vancouver CMA and Abbotsford-Mission CMA. This adjustment provides national consistency.

Table 2.1: Starts by Submarket and by Dwelling Type
British Columbia Region
January - June 2015

Submarket	Single		Semi		Row		Apt. & Other		Total		
	YTD 2015	YTD 2014	YTD 2015	YTD 2014	YTD 2015	YTD 2014	YTD 2015	YTD 2014	YTD 2015	YTD 2014	% Change
Centres 100,000+											
Abbotsford-Mission	137	96	4	0	32	0	97	160	270	256	5.5
Kelowna	273	308	102	72	51	71	125	94	551	545	1.1
Vancouver	2,254	1,998	272	226	1,077	1,287	6,335	5,594	9,938	9,105	9.1
Victoria	303	260	44	20	70	30	567	286	984	596	65.1
Centres 50,000 - 99,999											
Chilliwack	137	127	24	18	67	63	109	112	337	320	5.3
Courtenay[1]	81	70	32	16	30	8	105	23	248	117	112.0
Kamloops	129	108	30	20	25	8	23	92	207	228	-9.2
Nanaimo	199	164	16	16	34	21	248	65	497	266	86.8
Prince George	81	53	8	2	10	0	48	3	147	58	153.4
Vernon	105	71	24	4	11	18	3	2	143	95	50.5
Centres 10,000 - 49,999											
Campbell River	43	73	6	20	0	0	1	0	50	93	-46.2
Cranbrook	25	31	0	0	3	0	0	0	28	31	-9.7
Dawson Creek	16	8	6	78	4	33	11	46	37	165	-77.6
Duncan	73	65	0	2	0	0	12	43	85	110	-22.7
Fort St. John	55	36	28	30	116	0	51	0	250	66	**
Nelson[1]	3	2	0	2	0	0	54	0	57	4	**
Parksville-Qualicum Beach	83	44	10	8	16	4	0	0	109	56	94.6
Penticton	60	62	22	6	22	0	27	8	131	76	72.4
Port Alberni	14	23	2	2	0	0	0	0	16	25	-36.0
Powell River	4	11	0	0	0	0	0	0	4	11	-63.6
Prince Rupert	6	2	2	0	0	0	0	0	8	2	**
Quesnel	6	9	0	0	0	0	0	0	6	9	-33.3
Salmon Arm	30	19	0	0	3	12	1	25	34	56	-39.3
Salt Spring Island[1]	14	3	0	0	0	0	0	0	14	3	**
Squamish	35	22	6	14	28	0	10	2	79	38	107.9
Summerland	11	5	4	0	3	0	0	0	18	5	**
Terrace	13	23	2	0	15	0	2	28	32	51	-37.3
Williams Lake	6	9	0	0	0	0	0	0	6	9	-33.3
Total British Columbia (10,000+)	4,196	3,702	644	556	1,617	1,555	7,829	6,583	14,286	12,396	15.2

Source: CMHC (Starts and Completions Survey)
[1]This centre is new to our survey as of 2013

Effective January 2013, single-detached houses with an attached accessory suite are recorded as one unit "Ownership, Single" and the accessory suite as one unit "Rental, Apt + Other". In 2012 and prior years, these structures were recorded as two units, "Ownership, Freehold, Apt + Other" in some markets, including the Vancouver CMA and Abbotsford-Mission CMA. This adjustment provides national consistency.

Table 2.2: Starts by Submarket, by Dwelling Type and by Intended Market British Columbia Region Second Quarter 2015								
Submarket	Row				Apt. & Other			
	Freehold and Condominium		Rental		Freehold and Condominium		Rental	
	Q2 2015	Q2 2014	Q2 2015	Q2 2014	Q2 2015	Q2 2014	Q2 2015	Q2 2014
Centres 100,000+								
Abbotsford-Mission	0	0	0	0	0	146	26	8
Kelowna	10	48	0	0	86	66	21	13
Vancouver	565	665	0	0	2,655	2,245	1,023	565
Victoria	26	11	0	0	50	50	247	187
Centres 50,000 - 99,999								
Chilliwack	33	52	0	0	109	0	0	44
Courtenay	8	4	0	0	0	4	7	2
Kamloops	19	4	0	0	0	0	22	4
Nanaimo	31	7	0	0	38	0	153	41
Prince George	10	0	0	0	42	0	5	3
Vernon	3	18	0	0	0	0	2	1
Centres 10,000 - 49,999								
Campbell River	0	0	0	0	0	0	1	0
Cranbrook	0	0	0	0	0	0	0	0
Dawson Creek	4	33	0	0	0	0	9	26
Duncan	0	0	0	0	8	15	3	2
Fort St. John	92	0	8	0	0	0	1	0
Nelson[1]	0	0	0	0	0	0	0	0
Parksville-Qualicum Beach	6	4	0	0	0	0	0	0
Penticton	8	0	0	0	0	0	5	6
Port Alberni	0	0	0	0	0	0	0	0
Powell River	0	0	0	0	0	0	0	0
Prince Rupert	0	0	0	0	0	0	0	0
Quesnel	0	0	0	0	0	0	0	0
Salmon Arm	3	9	0	0	0	24	0	1
Salt Spring Island[1]	0	0	0	0	0	0	0	0
Squamish	9	0	0	0	0	0	4	2
Summerland	0	0	0	0	0	0	0	0
Terrace	12	0	0	0	0	25	1	3
Williams Lake	0	0	0	0	0	0	0	0
Total British Columbia (10,000+)	839	855	8	0	2,988	2,575	1,530	908

Source: CMHC (Starts and Completions Survey)

[1]This centre is new to our survey as of 2013

Effective January 2013, single-detached houses with an attached accessory suite are recorded as one unit "Ownership, Single" and the accessory suite as one unit "Rental, Apt + Other". In 2012 and prior years, these structures were recorded as two units, "Ownership, Freehold, Apt + Other" in some markets, including the Vancouver CMA and Abbotsford-Mission CMA. This adjustment provides national consistency.

Table 2.3: Starts by Submarket, by Dwelling Type and by Intended Market
British Columbia Region
January - June 2015

Submarket	Row				Apt. & Other			
	Freehold and Condominium		Rental		Freehold and Condominium		Rental	
	YTD 2015	YTD 2014	YTD 2015	YTD 2014	YTD 2015	YTD 2014	YTD 2015	YTD 2014
Centres 100,000+								
Abbotsford-Mission	32	0	0	0	67	146	30	14
Kelowna	51	71	0	0	86	66	39	28
Vancouver	1,077	1,287	0	0	4,764	4,337	1,571	1,257
Victoria	70	30	0	0	248	80	319	206
Centres 50,000 - 99,999								
Chilliwack	67	63	0	0	109	68	0	44
Courtenay	30	8	0	0	0	19	105	4
Kamloops	25	8	0	0	0	0	23	92
Nanaimo	34	21	0	0	38	0	210	65
Prince George	10	0	0	0	42	0	6	3
Vernon	11	18	0	0	0	0	3	2
Centres 10,000 - 49,999								
Campbell River	0	0	0	0	0	0	1	0
Cranbrook	3	0	0	0	0	0	0	0
Dawson Creek	4	33	0	0	0	0	11	46
Duncan	0	0	0	0	8	40	4	3
Fort St. John	108	0	8	0	50	0	1	0
Nelson[1]	0	0	0	0	54	0	0	0
Parksville-Qualicum Beach	16	4	0	0	0	0	0	0
Penticton	22	0	0	0	0	0	27	8
Port Alberni	0	0	0	0	0	0	0	0
Powell River	0	0	0	0	0	0	0	0
Prince Rupert	0	0	0	0	0	0	0	0
Quesnel	0	0	0	0	0	0	0	0
Salmon Arm	3	12	0	0	0	24	1	1
Salt Spring Island[1]	0	0	0	0	0	0	0	0
Squamish	28	0	0	0	0	0	10	2
Summerland	3	0	0	0	0	0	0	0
Terrace	15	0	0	0	0	25	2	3
Williams Lake	0	0	0	0	0	0	0	0
Total British Columbia (10,000+)	1,609	1,555	8	0	5,466	4,805	2,363	1,778

Source: CMHC (Starts and Completions Survey)

[1]This centre is new to our survey as of 2013

Effective January 2013, single-detached houses with an attached accessory suite are recorded as one unit "Ownership, Single" and the accessory suite as one unit "Rental, Apt + Other". In 2012 and prior years, these structures were recorded as two units, "Ownership, Freehold, Apt + Other" in some markets, including the Vancouver CMA and Abbotsford-Mission CMA. This adjustment provides national consistency.

Table 2.4: Starts by Submarket and by Intended Market British Columbia Region Second Quarter 2015								
Submarket	Freehold		Condominium		Rental		Total*	
	Q2 2015	Q2 2014	Q2 2015	Q2 2014	Q2 2015	Q2 2014	Q2 2015	Q2 2014
Centres 100,000+								
Abbotsford-Mission	88	48	1	146	32	13	121	207
Kelowna	194	190	118	114	26	32	338	336
Vancouver	1,239	1,198	3,270	2,847	1,146	687	5,655	4,732
Victoria	179	149	79	63	250	193	508	405
Centres 50,000 - 99,999								
Chilliwack	94	57	154	71	0	45	248	173
Courtenay	47	39	20	19	8	3	75	61
Kamloops	73	102	60	4	22	7	155	113
Nanaimo	98	102	84	11	153	44	335	157
Prince George	47	38	58	0	5	3	110	41
Vernon	60	43	7	18	2	4	69	65
Centres 10,000 - 49,999								
Campbell River	24	36	4	16	1	1	29	53
Cranbrook	13	27	0	0	4	0	17	27
Dawson Creek	15	62	4	33	9	30	28	125
Duncan	38	40	9	15	6	4	53	59
Fort St. John	63	38	91	0	9	0	163	38
Nelson[1]	2	4	0	0	0	0	2	4
Parksville-Qualicum Beach	28	22	9	12	2	0	39	34
Penticton	50	44	8	0	6	10	64	54
Port Alberni	7	10	0	0	0	0	7	10
Powell River	0	4	0	0	0	0	0	4
Prince Rupert	5	1	0	0	1	0	6	1
Quesnel	4	7	0	0	0	0	4	7
Salmon Arm	19	14	0	33	2	1	21	48
Salt Spring Island[1]	2	0	0	0	0	0	2	0
Squamish	21	24	9	0	7	3	37	27
Summerland	4	3	0	0	0	0	4	3
Terrace	11	15	12	25	3	3	26	43
Williams Lake	5	9	0	0	0	0	5	9
Total British Columbia (10,000+)	2,430	2,326	3,997	3,427	1,694	1,083	8,121	6,836

Source: CMHC (Starts and Completions Survey)

[1]This centre is new to our survey as of 2013

Effective January 2013, single-detached houses with an attached accessory suite are recorded as one unit "Ownership, Single" and the accessory suite as one unit "Rental, Apt + Other". In 2012 and prior years, these structures were recorded as two units, "Ownership, Freehold, Apt + Other" in some markets, including the Vancouver CMA and Abbotsford-Mission CMA. This adjustment provides national consistency.

Table 2.5: Starts by Submarket and by Intended Market British Columbia Region January - June 2015								
Submarket	Freehold		Condominium		Rental		Total*	
	YTD 2015	YTD 2014	YTD 2015	YTD 2014	YTD 2015	YTD 2014	YTD 2015	YTD 2014
Centres 100,000+								
Abbotsford-Mission	126	88	100	146	44	22	270	256
Kelowna	324	334	176	162	51	49	551	545
Vancouver	2,162	2,008	5,967	5,624	1,809	1,473	9,938	9,105
Victoria	329	253	330	113	325	230	984	596
Centres 50,000 - 99,999								
Chilliwack	127	118	210	157	0	45	337	320
Courtenay	89	71	52	41	107	5	248	117
Kamloops	106	124	78	8	23	96	207	228
Nanaimo	191	160	93	31	213	75	497	266
Prince George	82	52	59	3	6	3	147	58
Vernon	124	72	15	18	4	5	143	95
Centres 10,000 - 49,999								
Campbell River	45	66	4	26	1	1	50	93
Cranbrook	21	31	3	0	4	0	28	31
Dawson Creek	21	82	4	33	12	50	37	165
Duncan	64	65	14	40	7	5	85	110
Fort St. John	84	66	157	0	9	0	250	66
Nelson[1]	3	4	54	0	0	0	57	4
Parksville-Qualicum Beach	79	44	25	12	5	0	109	56
Penticton	79	64	24	0	28	12	131	76
Port Alberni	16	25	0	0	0	0	16	25
Powell River	4	11	0	0	0	0	4	11
Prince Rupert	7	2	0	0	1	0	8	2
Quesnel	6	9	0	0	0	0	6	9
Salmon Arm	27	19	4	36	3	1	34	56
Salt Spring Island[1]	14	3	0	0	0	0	14	3
Squamish	38	35	28	0	13	3	79	38
Summerland	9	5	9	0	0	0	18	5
Terrace	13	23	15	25	4	3	32	51
Williams Lake	6	9	0	0	0	0	6	9
Total British Columbia (10,000+)	4,196	3,843	7,421	6,475	2,669	2,078	14,286	12,396

Source: CMHC (Starts and Completions Survey)

[1]This centre is new to our survey as of 2013

Effective January 2013, single-detached houses with an attached accessory suite are recorded as one unit "Ownership, Single" and the accessory suite as one unit "Rental, Apt + Other". In 2012 and prior years, these structures were recorded as two units, "Ownership, Freehold, Apt + Other" in some markets, including the Vancouver CMA and Abbotsford-Mission CMA. This adjustment provides national consistency.

Table 3: Completions by Submarket and by Dwelling Type
British Columbia Region
Second Quarter 2015

Submarket	Single		Semi		Row		Apt. & Other		Total		
	Q2 2015	Q2 2014	Q2 2015	Q2 2014	Q2 2015	Q2 2014	Q2 2015	Q2 2014	Q2 2015	Q2 2014	% Change
Centres 100,000+											
Abbotsford-Mission	72	62	0	0	25	35	69	74	166	171	-2.9
Kelowna	171	157	36	24	34	14	21	15	262	210	24.8
Vancouver	1,055	877	164	86	679	652	2,562	1,690	4,460	3,305	34.9
Victoria	129	177	12	16	36	10	415	439	592	642	-7.8
Centres 50,000 - 99,999											
Chilliwack	102	50	14	14	37	20	40	0	193	84	129.8
Courtenay	48	32	12	2	7	0	8	2	75	36	108.3
Kamloops	71	56	14	10	4	4	43	1	132	71	85.9
Nanaimo	63	61	4	13	13	4	95	23	175	101	73.3
Prince George	71	38	2	2	0	14	22	2	95	56	69.6
Vernon	46	34	6	2	0	9	1	3	53	48	10.4
Centres 10,000 - 49,999											
Campbell River	26	26	0	6	0	10	0	0	26	42	-38.1
Cranbrook	20	17	0	0	0	3	0	0	20	20	0.0
Dawson Creek	16	6	8	18	0	51	5	36	29	111	-73.9
Duncan	37	43	0	10	0	0	37	1	74	54	37.0
Fort St. John	23	29	24	8	0	4	0	0	47	41	14.6
Nelson[1]	2	3	4	2	0	0	0	0	6	5	20
Parksville-Qualicum Beach	28	33	4	0	16	0	0	1	48	34	41.2
Penticton	32	23	0	2	0	0	4	2	36	27	33.3
Port Alberni	10	11	2	0	0	0	0	1	12	12	0.0
Powell River	2	6	2	0	0	0	0	0	4	6	-33.3
Prince Rupert	2	1	0	0	0	0	0	0	2	1	100.0
Quesnel	4	8	0	0	0	0	0	0	4	8	-50.0
Salmon Arm	16	14	0	0	0	0	2	2	18	16	12.5
Salt Spring Island[1]	5	3	0	0	0	0	0	3	5	6	-17
Squamish	16	14	6	6	0	16	4	1	26	37	-29.7
Summerland	3	7	2	0	0	0	0	0	5	7	-28.6
Terrace	10	13	2	0	0	3	3	0	15	16	-6.3
Williams Lake	5	4	0	0	0	0	1	0	6	4	50.0
Total British Columbia (10,000+	2,085	1,805	318	221	851	849	3,332	2,296	6,586	5,171	27.4

Source: CMHC (Starts and Completions Survey)
[1]This centre is new to our survey as of 2013

Effective January 2013, single-detached houses with an attached accessory suite are recorded as one unit "Ownership, Single" and the accessory suite as one unit "Rental, Apt + Other". In 2012 and prior years, these structures were recorded as two units, "Ownership, Freehold, Apt + Other" in some markets, including the Vancouver CMA and Abbotsford-Mission CMA. This adjustment provides national consistency.

Table 3.1: Completions by Submarket and by Dwelling Type British Columbia Region January - June 2015												
Submarket	Single		Semi		Row		Apt. & Other		Total			
	YTD 2015	YTD 2014	YTD 2015	YTD 2014	YTD 2015	YTD 2014	YTD 2015	YTD 2014	YTD 2015	YTD 2014	% Change
Centres 100,000+											
Abbotsford-Mission	109	106	0	0	44	41	167	144	320	291	10.0
Kelowna	332	292	68	44	82	38	40	44	522	418	24.9
Vancouver	1,906	1,916	274	270	1,212	1,083	4,362	4,634	7,754	7,903	-1.9
Victoria	270	312	28	36	40	55	491	585	829	988	-16.1
Centres 50,000 - 99,999											
Chilliwack	138	99	20	22	65	27	40	0	263	148	77.7
Courtenay	83	57	18	6	11	4	11	4	123	71	73.2
Kamloops	143	105	26	16	4	18	171	52	344	191	80.1
Nanaimo	130	117	10	21	16	11	126	44	282	193	46.1
Prince George	102	58	6	4	0	14	25	3	133	79	68.4
Vernon	89	54	10	2	18	19	1	6	118	81	45.7
Centres 10,000 - 49,999											
Campbell River	52	64	2	10	0	10	0	39	54	123	-56.1
Cranbrook	45	39	0	0	0	3	0	0	45	42	7.1
Dawson Creek	38	13	32	24	42	63	82	36	194	136	42.6
Duncan	60	68	0	14	0	13	38	4	98	99	-1.0
Fort St. John	54	54	72	44	29	4	52	0	207	102	102.9
Nelson[1]	5	10	4	2	0	0	0	0	9	12	-25
Parksville-Qualicum Beach	59	52	26	0	26	0	1	6	112	58	93.1
Penticton	63	33	4	2	0	12	7	2	74	49	51.0
Port Alberni	19	18	4	0	4	0	0	1	27	19	42.1
Powell River	4	11	2	0	0	0	0	0	6	11	-45.5
Prince Rupert	3	2	0	0	0	0	0	0	3	2	50.0
Quesnel	17	23	0	0	0	0	0	0	17	23	-26.1
Salmon Arm	32	30	2	0	0	0	3	2	37	32	15.6
Salt Spring Island[1]	18	10	0	0	0	0	0	3	18	13	38
Squamish	29	26	8	6	0	16	6	2	43	50	-14.0
Summerland	9	16	2	0	0	0	0	0	11	16	-31.3
Terrace	20	24	2	0	0	3	13	0	35	27	29.6
Williams Lake	17	13	0	0	0	0	3	0	20	13	53.8
Total British Columbia (10,000+	3,846	3,622	620	523	1,593	1,434	5,639	5,611	11,698	11,190	4.5

Source: CMHC (Starts and Completions Survey)
[1]This centre is new to our survey as of 2013

Effective January 2013, single-detached houses with an attached accessory suite are recorded as one unit "Ownership, Single" and the accessory suite as one unit "Rental, Apt + Other". In 2012 and prior years, these structures were recorded as two units, "Ownership, Freehold, Apt + Other" in some markets, including the Vancouver CMA and Abbotsford-Mission CMA. This adjustment provides national consistency.

Table 3.2: Completions by Submarket, by Dwelling Type and by Intended Market British Columbia Region Second Quarter 2015								
Submarket	Row				Apt. & Other			
	Freehold and Condominium		Rental		Freehold and Condominium		Rental	
	Q2 2015	Q2 2014	Q2 2015	Q2 2014	Q2 2015	Q2 2014	Q2 2015	Q2 2014
Centres 100,000+								
Abbotsford-Mission	25	35	0	0	60	0	9	74
Kelowna	34	14	0	0	0	0	21	15
Vancouver	679	652	0	0	1,857	1,275	705	415
Victoria	36	10	0	0	294	171	121	268
Centres 50,000 - 99,999								
Chilliwack	37	20	0	0	40	0	0	0
Courtenay	7	0	0	0	0	0	8	2
Kamloops	4	4	0	0	43	0	0	1
Nanaimo	13	4	0	0	62	0	33	23
Prince George	0	14	0	0	20	0	2	2
Vernon	0	9	0	0	0	0	1	3
Centres 10,000 - 49,999								
Campbell River	0	4	0	6	0	0	0	0
Cranbrook	0	3	0	0	0	0	0	0
Dawson Creek	0	29	0	22	0	0	5	36
Duncan	0	0	0	0	35	0	2	1
Fort St. John	0	4	0	0	0	0	0	0
Nelson[1]	0	0	0	0	0	0	0	0
Parksville-Qualicum Beach	4	0	12	0	0	0	0	1
Penticton	0	0	0	0	0	0	4	2
Port Alberni	0	0	0	0	0	0	0	1
Powell River	0	0	0	0	0	0	0	0
Prince Rupert	0	0	0	0	0	0	0	0
Quesnel	0	0	0	0	0	0	0	0
Salmon Arm	0	0	0	0	0	0	2	2
Salt Spring Island[1]	0	0	0	0	0	0	0	3
Squamish	0	16	0	0	0	0	4	1
Summerland	0	0	0	0	0	0	0	0
Terrace	0	3	0	0	0	0	3	0
Williams Lake	0	0	0	0	0	0	1	0
Total British Columbia (10,000+)	839	821	12	28	2,411	1,446	921	850

Source: CMHC (Starts and Completions Survey)
[1]This centre is new to our survey as of 2013

Effective January 2013, single-detached houses with an attached accessory suite are recorded as one unit "Ownership, Single" and the accessory suite as one unit "Rental, Apt + Other". In 2012 and prior years, these structures were recorded as two units, "Ownership, Freehold, Apt + Other" in some markets, including the Vancouver CMA and Abbotsford-Mission CMA. This adjustment provides national consistency.

Table 3.3: Completions by Submarket, by Dwelling Type and by Intended Market
British Columbia Region
January - June 2015

Submarket	Row				Apt. & Other			
	Freehold and Condominium		Rental		Freehold and Condominium		Rental	
	YTD 2015	YTD 2014	YTD 2015	YTD 2014	YTD 2015	YTD 2014	YTD 2015	YTD 2014
Centres 100,000+								
Abbotsford-Mission	44	41	0	0	150	0	17	144
Kelowna	82	38	0	0	0	0	40	44
Vancouver	1,212	1,083	0	0	3,226	3,658	1,136	976
Victoria	40	55	0	0	294	225	197	360
Centres 50,000 - 99,999								
Chilliwack	65	27	0	0	40	0	0	0
Courtenay	11	4	0	0	3	0	8	4
Kamloops	4	18	0	0	124	50	47	2
Nanaimo	16	11	0	0	62	0	64	44
Prince George	0	14	0	0	20	0	5	3
Vernon	18	19	0	0	0	0	1	6
Centres 10,000 - 49,999								
Campbell River	0	4	0	6	0	0	0	39
Cranbrook	0	3	0	0	0	0	0	0
Dawson Creek	42	33	0	30	0	0	82	36
Duncan	0	13	0	0	35	0	3	4
Fort St. John	29	4	0	0	51	0	1	0
Nelson[1]	0	0	0	0	0	0	0	0
Parksville-Qualicum Beach	8	0	18	0	0	0	1	6
Penticton	0	4	0	8	0	0	7	2
Port Alberni	0	0	4	0	0	0	0	1
Powell River	0	0	0	0	0	0	0	0
Prince Rupert	0	0	0	0	0	0	0	0
Quesnel	0	0	0	0	0	0	0	0
Salmon Arm	0	0	0	0	0	0	3	2
Salt Spring Island[1]	0	0	0	0	0	0	0	3
Squamish	0	16	0	0	0	0	6	2
Summerland	0	0	0	0	0	0	0	0
Terrace	0	3	0	0	9	0	4	0
Williams Lake	0	0	0	0	0	0	3	0
Total British Columbia (10,000+)	1,571	1,390	22	44	4,014	3,933	1,625	1,678

Source: CMHC (Starts and Completions Survey)
[1]This centre is new to our survey as of 2013

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Table 3.4: Completions by Submarket and by Intended Market British Columbia Region Second Quarter 2015								
Submarket	Freehold		Condominium		Rental		Total*	
	Q2 2015	Q2 2014	Q2 2015	Q2 2014	Q2 2015	Q2 2014	Q2 2015	Q2 2014
Centres 100,000+								
Abbotsford-Mission	60	56	85	35	21	80	166	171
Kelowna	179	165	56	14	27	31	262	210
Vancouver	1,047	862	2,621	1,936	792	507	4,460	3,305
Victoria	132	175	334	184	126	283	592	642
Centres 50,000 - 99,999								
Chilliwack	85	54	108	30	0	0	193	84
Courtenay	44	28	22	2	9	6	75	36
Kamloops	74	63	58	4	0	4	132	71
Nanaimo	65	55	77	14	33	32	175	101
Prince George	71	38	22	16	2	2	95	56
Vernon	51	32	0	9	2	7	53	48
Centres 10,000 - 49,999								
Campbell River	24	27	2	8	0	7	26	42
Cranbrook	20	17	0	3	0	0	20	20
Dawson Creek	21	24	0	29	8	58	29	111
Duncan	34	52	35	0	5	2	74	54
Fort St. John	47	37	0	4	0	0	47	41
Nelson[1]	6	5	0	0	0	0	6	5
Parksville-Qualicum Beach	26	32	6	1	16	1	48	34
Penticton	32	22	0	0	4	5	36	27
Port Alberni	12	10	0	1	0	1	12	12
Powell River	2	6	2	0	0	0	4	6
Prince Rupert	2	1	0	0	0	0	2	1
Quesnel	4	8	0	0	0	0	4	8
Salmon Arm	14	14	1	0	3	2	18	16
Salt Spring Island[1]	5	3	0	0	0	3	5	6
Squamish	20	20	0	16	6	1	26	37
Summerland	2	7	3	0	0	0	5	7
Terrace	11	13	0	3	4	0	15	16
Williams Lake	5	4	0	0	1	0	6	4
Total British Columbia (10,000+)	2,095	1,830	3,432	2,309	1,059	1,032	6,586	5,171

Source: CMHC (Starts and Completions Survey)

[1]This centre is new to our survey as of 2013

Effective January 2013, single-detached houses with an attached accessory suite are recorded as one unit "Ownership, Single" and the accessory suite as one unit "Rental, Apt + Other". In 2012 and prior years, these structures were recorded as two units, "Ownership, Freehold, Apt + Other" in some markets, including the Vancouver CMA and Abbotsford-Mission CMA. This adjustment provides national consistency.

Table 3.5: Completions by Submarket and by Intended Market
British Columbia Region
January - June 2015

Submarket	Freehold		Condominium		Rental		Total*	
	YTD 2015	YTD 2014	YTD 2015	YTD 2014	YTD 2015	YTD 2014	YTD 2015	YTD 2014
Centres 100,000+								
Abbotsford-Mission	95	95	194	41	31	155	320	291
Kelowna	325	308	136	40	61	70	522	418
Vancouver	1,870	1,966	4,562	4,763	1,322	1,174	7,754	7,903
Victoria	276	301	347	300	206	387	829	988
Centres 50,000 - 99,999								
Chilliwack	113	99	149	49	1	0	263	148
Courtenay	78	47	33	12	12	12	123	71
Kamloops	155	113	142	70	47	8	344	191
Nanaimo	134	106	82	21	66	66	282	193
Prince George	105	60	23	16	5	3	133	79
Vernon	97	51	18	19	3	11	118	81
Centres 10,000 - 49,999								
Campbell River	48	67	6	10	0	46	54	123
Cranbrook	45	39	0	3	0	0	45	42
Dawson Creek	63	40	42	29	89	67	194	136
Duncan	56	81	35	13	7	5	98	99
Fort St. John	126	98	80	4	1	0	207	102
Nelson[1]	9	12	0	0	0	0	9	12
Parksville-Qualicum Beach	59	50	18	2	35	6	112	58
Penticton	64	32	0	4	10	13	74	49
Port Alberni	23	16	0	2	4	1	27	19
Powell River	4	11	2	0	0	0	6	11
Prince Rupert	3	2	0	0	0	0	3	2
Quesnel	17	23	0	0	0	0	17	23
Salmon Arm	31	30	2	0	4	2	37	32
Salt Spring Island[1]	18	10	0	0	0	3	18	13
Squamish	32	32	0	16	11	2	43	50
Summerland	8	14	3	0	0	2	11	16
Terrace	20	24	9	3	6	0	35	27
Williams Lake	17	13	0	0	3	0	20	13
Total British Columbia (10,000+)	3,891	3,740	5,883	5,417	1,924	2,033	11,698	11,190

Source: CMHC (Starts and Completions Survey)
[1]This centre is new to our survey as of 2013

Effective January 2013, single-detached houses with an attached accessory suite are recorded as one unit "Ownership, Single" and the accessory suite as one unit "Rental, Apt + Other". In 2012 and prior years, these structures were recorded as two units, "Ownership, Freehold, Apt + Other" in some markets, including the Vancouver CMA and Abbotsford-Mission CMA. This adjustment provides national consistency.

Table 4: Absorbed Single-Detached Units by Price Range in British Columbia Region
Second Quarter 2015

Submarket	Price Ranges										Total	Median Price ($)	Average Price ($)
	< $300,000		$300,000 - $399,999		$400,000 - $499,999		$500,000 - $649,999		$650,000 +				
	Units	Share (%)	Units	Share (%)	Units	Share (%)	Units	Share (%)	Units	Share (%)			
Chilliwack													
Q2 2015	7	6.2	35	31.0	52	46.0	16	14.2	3	2.7	113	420,000	429,494
Q2 2014	1	2.0	6	12.2	33	67.3	9	18.4	0	0.0	49	459,000	463,377
Year-to-date 2015	7	4.8	42	28.6	66	44.9	28	19.0	4	2.7	147	434,900	439,664
Year-to-date 2014	2	1.6	35	28.7	69	56.6	16	13.1	0	0.0	122	437,000	436,470
Courtenay													
Q2 2015	0	0.0	13	34.2	5	13.2	14	36.8	6	15.8	38	500,000	512,550
Q2 2014	0	0.0	6	16.7	12	33.3	6	16.7	12	33.3	36	494,050	574,144
Year-to-date 2015	2	2.7	24	32.9	11	15.1	26	35.6	10	13.7	73	488,250	499,085
Year-to-date 2014	1	1.5	10	15.2	20	30.3	16	24.2	19	28.8	66	512,200	571,303
Kamloops													
Q2 2015	4	5.8	11	15.9	34	49.3	17	24.6	3	4.3	69	449,000	459,360
Q2 2014	5	9.8	8	15.7	21	41.2	9	17.6	8	15.7	51	461,895	479,997
Year-to-date 2015	9	6.5	23	16.7	64	46.4	30	21.7	12	8.7	138	455,950	475,363
Year-to-date 2014	8	7.8	18	17.6	46	45.1	20	19.6	10	9.8	102	456,719	464,716
Nanaimo													
Q2 2015	4	6.3	25	39.7	13	20.6	15	23.8	6	9.5	63	439,110	478,861
Q2 2014	2	3.9	13	25.5	22	43.1	9	17.6	5	9.8	51	445,000	484,175
Year-to-date 2015	4	3.1	50	38.2	35	26.7	27	20.6	15	11.5	131	440,000	488,672
Year-to-date 2014	4	3.9	31	30.1	40	38.8	19	18.4	9	8.7	103	438,900	469,371
Prince George													
Q2 2015	10	16.1	24	38.7	18	29.0	7	11.3	3	4.8	62	396,003	421,113
Q2 2014	4	12.5	9	28.1	14	43.8	4	12.5	1	3.1	32	428,453	422,406
Year-to-date 2015	15	16.9	31	34.8	29	32.6	11	12.4	3	3.4	89	399,000	418,588
Year-to-date 2014	9	15.3	18	30.5	21	35.6	9	15.3	2	3.4	59	419,900	417,322
Vernon													
Q2 2015	1	2.5	8	20.0	4	10.0	13	32.5	14	35.0	40	600,000	645,599
Q2 2014	0	0.0	2	5.9	1	2.9	13	38.2	18	52.9	34	715,830	775,605
Year-to-date 2015	1	1.2	18	22.0	9	11.0	17	20.7	37	45.1	82	603,975	696,670
Year-to-date 2014	0	0.0	2	3.6	4	7.1	23	41.1	27	48.2	56	636,200	735,397
Abbotsford-Mission CMA													
Q2 2015	1	1.6	1	1.6	30	49.2	19	31.1	10	16.4	61	490,000	537,456
Q2 2014	0	0.0	1	1.7	19	32.8	31	53.4	7	12.1	58	550,950	563,335
Year-to-date 2015	2	2.0	1	1.0	40	40.0	40	40.0	17	17.0	100	537,900	551,507
Year-to-date 2014	0	0.0	2	1.8	36	32.4	53	47.7	20	18.0	111	565,900	570,634
Kelowna CMA													
Q2 2015	2	1.5	12	8.9	20	14.8	48	35.6	53	39.3	135	600,000	662,799
Q2 2014	6	4.2	12	8.5	40	28.2	44	31.0	40	28.2	142	540,125	624,477
Year-to-date 2015	4	1.4	20	7.1	51	18.2	99	35.4	106	37.9	280	589,500	681,847
Year-to-date 2014	12	4.5	26	9.7	71	26.4	69	25.7	91	33.8	269	549,900	672,600
Vancouver CMA													
Q2 2015	0	0.0	0	0.0	19	1.8	107	10.0	945	88.2	1,071	1,090,000	1,456,514
Q2 2014	1	0.1	1	0.1	15	1.5	99	10.2	855	88.1	971	1,100,000	1,370,588
Year-to-date 2015	0	0.0	0	0.0	26	1.3	192	9.9	1,727	88.8	1,945	1,180,000	1,478,195
Year-to-date 2014	1	0.1	1	0.1	25	1.3	176	8.9	1,772	89.7	1,975	1,190,000	1,520,819

Source: CMHC (Market Absorption Survey)

Submarket	< $300,000		$300,000 - $399,999		$400,000 - $499,999		$500,000 - $649,999		$650,000 +		Total	Median Price ($)	Average Price ($)
	Units	Share (%)	Units	Share (%)	Units	Share (%)	Units	Share (%)	Units	Share (%)			
Victoria CMA													
Q2 2015	0	0.0	12	9.8	31	25.2	39	31.7	41	33.3	123	569,900	703,140
Q2 2014	3	1.9	23	14.6	19	12.0	42	26.6	56	35.4	158	549,900	664,525
Year-to-date 2015	2	0.8	42	16.4	15	5.9	74	28.9	79	30.9	256	549,950	655,621
Year-to-date 2014	5	1.8	33	11.8	26	9.3	88	31.5	96	34.4	279	569,000	678,383
Total Urban Centres in British Columbia (50,000+)													
Q2 2015	29	1.6	141	7.9	226	12.7	295	16.6	1,084	61.1	1,775	774,900	1,098,863
Q2 2014	22	1.4	81	5.1	211	13.3	266	16.8	1,002	63.3	1,582	789,277	1,068,028
Year-to-date 2015	46	1.4	251	7.7	390	12.0	544	16.8	2,010	62.0	3,241	789,000	1,115,105
Year-to-date 2014	42	1.3	176	5.6	389	12.4	489	15.6	2,046	65.1	3,142	820,750	1,174,304

Table 4: Absorbed Single-Detached Units by Price Range in British Columbia Region, Second Quarter 2015 (Price Ranges)

Source: CMHC (Market Absorption Survey)

Table 5: MLS® Residential Activity for British Columbia Region Second Quarter 2015

		Number of Sales[1]	Yr/Yr[2] (%)	Sales SA[1]	Number of New Listings[1]	New Listings SA[1]	Sales-to-New Listings SA[2]	Average Price[1] ($)	Yr/Yr[2] (%)	Average Price[1] ($) SA
2014	January	4,244	24.5	6,588	12,756	12,507	52.7	565,036	9.9	562,154
	February	5,578	23.9	6,548	12,237	12,299	53.2	611,688	15.4	594,080
	March	6,613	16.8	6,156	14,139	12,350	49.8	562,316	4.0	543,066
	April	7,730	12.0	6,719	16,612	12,760	52.7	561,613	6.3	550,226
	May	8,729	13.9	7,034	16,959	12,753	55.2	565,233	5.8	555,658
	June	8,989	24.9	7,221	15,037	12,736	56.7	556,977	4.5	559,471
	July	8,493	11.0	7,079	13,937	12,521	56.5	548,162	2.6	565,568
	August	7,341	7.0	7,255	11,383	12,541	57.9	560,318	5.0	575,077
	September	7,636	17.5	7,365	13,149	12,450	59.2	574,641	7.1	588,595
	October	7,648	14.6	7,408	11,325	12,593	58.8	575,504	6.5	578,383
	November	5,972	8.8	7,351	7,957	12,595	58.4	574,694	3.1	581,598
	December	5,076	14.7	7,324	5,214	12,605	58.1	585,718	3.0	588,026
2015	January	4,377	3.1	7,248	12,006	12,552	57.7	593,155	5.0	593,513
	February	6,661	19.4	7,995	13,275	13,239	60.4	639,405	4.5	617,204
	March	9,101	37.6	8,273	16,130	13,185	62.7	641,799	14.1	619,012
	April	9,952	28.7	8,414	16,257	12,527	67.2	634,744	13.0	622,389
	May	10,174	16.6	8,509	15,866	12,517	68.0	632,182	11.8	624,464
	June	11,294	25.6	8,547	15,907	12,667	67.5	631,962	13.5	635,084
	July									
	August									
	September									
	October									
	November									
	December									
	Q2 2014	25,448	16.9	20,974	48,608	38,249	54.8	561,217	5.5	555,230
	Q2 2015	31,420	23.5	25,470	48,030	37,711	67.5	632,914	12.8	627,342
	YTD 2014	41,883	18.5		87,740			568,499	7.0	
	YTD 2015	51,559	23.1		89,441			631,946	11.2	

MLS® is a registered trademark of the Canadian Real Estate Association (CREA).

[1]Source: CREA

[2]Source: CMHC, adapted from MLS® data supplied by CREA

Table 6: Level of Economic Indicators for British Columbia Region Second Quarter 2015												
		Interest Rates			Employment SA (,000)	Unemployment Rate (%) SA	Migration Total Net	Consumer Confidence Index (2002=100)	Average Weekly Wages ($)	Manufacturing Shipments ($,000)	Exchange Rate (U.S. cents)
		P & I Per $100,000	Mortgage Rates (%) 1 Yr. Term	Mortgage Rates (%) 5 Yr. Term							
2014	January - March	591	3.1	5.2	2,276.8	6.3	9,989	101.0	877	9,704,369	90.18
	April - June	570	3.1	4.8	2,279.8	6.1	11,563	105.1	875	11,053,190	92.39
	July - September	570	3.1	4.8	2,273.7	6.2	22,969	107.6	887	11,171,830	90.97
	October - December	570	3.1	4.8	2,281.7	5.8	-589	127.4	889	10,878,257	87.43
2015	January - March	568	3.0	4.8	2,287.8	5.8	6,121	118.0	909	10,556,118	79.20
	April - June	561	2.9	4.6	2,286.1	6.1		112.4	917		81.10
	July - September										
	October - December										

Table 6.1: Growth (1) of Economic Indicators for British Columbia Region Second Quarter 2015											
		Interest Rates			Employment SA	Unemployment Rate SA	Migration Total Net	Consumer Confidence Index	Average Weekly Wages	Manufacturing Shipments	Exchange Rate
		P & I Per $100,000	Mortgage Rates 1 Yr. Term	Mortgage Rates 5 Yr. Term							
2014	January - March	-0.5	0.1	0.0	0.8	-0.5	45.1	12.1	0.5	3.3	-8.5
	April - June	-3.4	0.1	-0.4	0.6	-0.4	11.3	21.0	0.3	7.8	-4.7
	July - September	-4.6	0.0	-0.5	0.1	-0.4	36.6	-2.2	0.2	9.5	-5.7
	October - December	-5.2	0.0	-0.6	0.8	-0.9	29.5	27.3	0.1	6.0	-7.7
2015	January - March	-3.8	-0.2	-0.4	0.5	-0.5	-38.7	16.8	3.6	8.8	-12.2
	April - June	-1.5	-0.3	-0.2	0.3	0.0		7.0	4.8		-12.2
	July - September										
	October - December										

"P & I" means Principal and Interest (assumes $100,000 mortgage amortized over 25 years using current 5 year interest rate)
"NHPI" means New Housing Price Index
"CPI" means Consumer Price Index
"SA" means Seasonally Adjusted
(1) Growth year over year expressed in percentage

Source: CMHC, adapted from Statistics Canada (CANSIM), Statistics Canada (CANSIM), Conference Board of Canada

METHODOLOGY

Starts & Completions Survey Methodology

The Starts and Completions Survey is conducted by way of site visits which are used to confirm that new units have reached set stages in the construction process. Since most municipalities in the country issue building permits, these are used as an indication of where construction is likely to take place. In areas where there are no permits, reliance has to be placed either on local sources or searching procedures.

The Starts and Completions Survey is carried out monthly in urban areas with population in excess of 50,000, as defined by the 2011 Census. In urban areas with populations of 10,000 to 49,999, all Starts are enumerated in the last month of the quarter (i.e. four times a year, in March, June, September and December). In these centres with quarterly enumeration, Completion activity is modeled based on historical patterns. Monthly Starts and Completions activity in these quarterly locations are statistically estimated at a provincial level for single and multi categories. Centres with populations below 10,000 are enumerated on a sample basis, also in the last month of each quarter (i.e. four times a year, in March, June, September and December).

The Starts and Completions Survey enumerates dwelling units in new structures only, designed for non-transient and year-round occupancy.

Mobile homes are included in the surveys. A mobile home is a type of manufactured house that is completely assembled in a factory and then moved to a foundation before it is occupied.

Trailers or any other movable dwelling (the larger often referred to as a mobile home) with no permanent foundation are excluded from the survey.

Conversions and/or alterations within an existing structure are excluded from the surveys as are seasonal dwellings, such as: summer cottages, hunting and ski cabins, trailers and boat houses; and hostel accommodations, such as: hospitals, nursing homes, penal institutions, convents, monasteries, military and industrial camps, and collective types of accommodation such as: hotels, clubs, and lodging homes.

Market Absorption Survey Methodology

The Market Absorption Survey is carried out in conjunction with the Starts and Completions Survey in urban areas with populations in excess of 50,000. When a structure is recorded as completed, an update is also made as units are sold or rented. The dwellings are then enumerated each month until such time as full absorption occurs.

STARTS AND COMPLETIONS SURVEY AND MARKET ABSORPTION SURVEY DEFINITIONS

A "**dwelling unit**", for purposes of the Starts and Completions Survey, is defined as a structurally separate set of self-contained living premises with a private entrance from outside the building or from a common hall, lobby, or stairway inside the building. Such an entrance must be one that can be used without passing through another separate dwelling unit.

A "**start**", for purposes of the Starts and Completions Survey, is defined as the beginning of construction work on a building, usually when the concrete has been poured for the whole of the footing around the structure, or an equivalent stage where a basement will not be part of the structure.

The number of units "**under construction**" as at the end of the period shown, takes into account certain adjustments which are necessary for various reasons. For example, after a start on a dwelling has commenced construction may cease, or a structure, when completed, may contain more or fewer dwelling units than were reported at start.

A "**completion**", for purposes of the Starts and Completions Survey, is defined as the stage at which all the proposed construction work on a dwelling unit has been performed, although under some circumstances a dwelling may be counted as completed where up to 10 per cent of the proposed work remains to be done.

The term "**absorbed**" means that a housing unit is no longer on the market (i.e. has been sold or rented). This usually happens when a binding contract is secured by a non-refundable deposit and has been signed by a qualified purchaser. The purpose of the Market Absorption Survey is to measure the rate at which units are sold or rented after they are completed, as well as collect prices.

DWELLING TYPES:

A "**Single-Detached**" dwelling (also referred to as "**Single**") is a building containing only one dwelling unit, which is completely separated on all sides from any other dwelling or structure. Includes link homes, where two units may share a common basement wall but are separated above grade. Also includes cluster-single developments.

A "**Semi-Detached (Double)**" dwelling (also referred to as "**Semi**") is one of two dwellings located side-by-side in a building, adjoining no other structure and separated by a common or party wall extending from ground to roof.

A "**Row (Townhouse)**" dwelling is a one family dwelling unit in a row of three or more attached dwellings separated by a common or party wall extending from ground to roof.

The term "**Apartment and other**" includes all dwellings other than those described above, including structures commonly known as stacked townhouses, duplexes, triplexes, double duplexes and row duplexes.

INTENDED MARKET:

The "**intended market**" is the tenure in which the unit is being marketed. This includes the following categories:

Freehold: A residence where the owner owns the dwelling and lot outright.

Condominium (including Strata-Titled): An individual dwelling which is privately owned, but where the building and/or the land are collectively owned by all dwelling unit owners. A condominium is a form of ownership rather than a type of house.

Rental: Dwelling constructed for rental purposes regardless of who finances the structure.

GEOGRAPHICAL TERMS:

A census metropolitan area (CMA) or a census agglomeration (CA) is formed by one or more adjacent municipalities centred on a large urban area (known as the urban core). The census population count of the urban core is at least 10,000 to form a census agglomeration and at least 100,000 to form a census metropolitan area. To be included in the CMA or CA, other adjacent municipalities must have a high degree on integration with the central urban area, as measured by commuting flows derived from census place of work data. CMAs and CAs contain whole municipalities or Census Subdivisions.

A "**Rural**" area, for the purposes of this publication, is a centre with a population less than 10,000.

All data presented in this publication is based on Statistics Canada's 2006 Census area definitions.

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HOUSING MARKET INFORMATION

HOUSING MARKET OUTLOOK
British Columbia Region Highlights

CANADA MORTGAGE AND HOUSING CORPORATION

Date Released: Fourth Quarter 2015

Housing Market Forecast

Figure 1

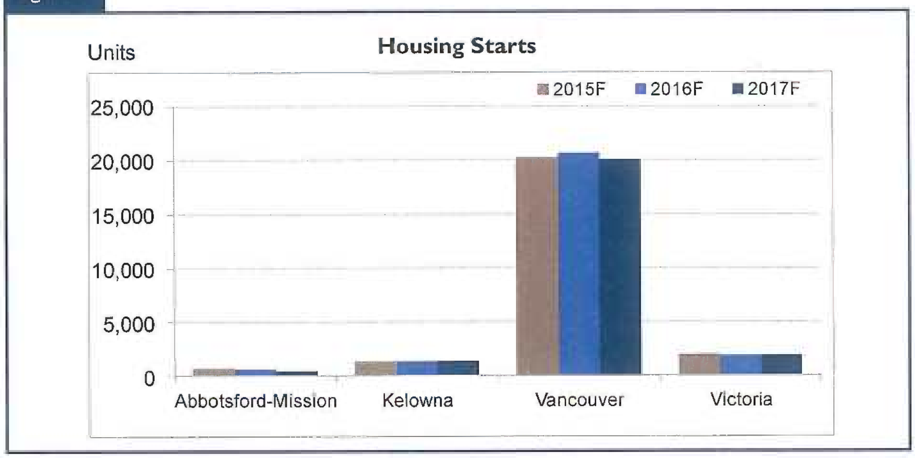
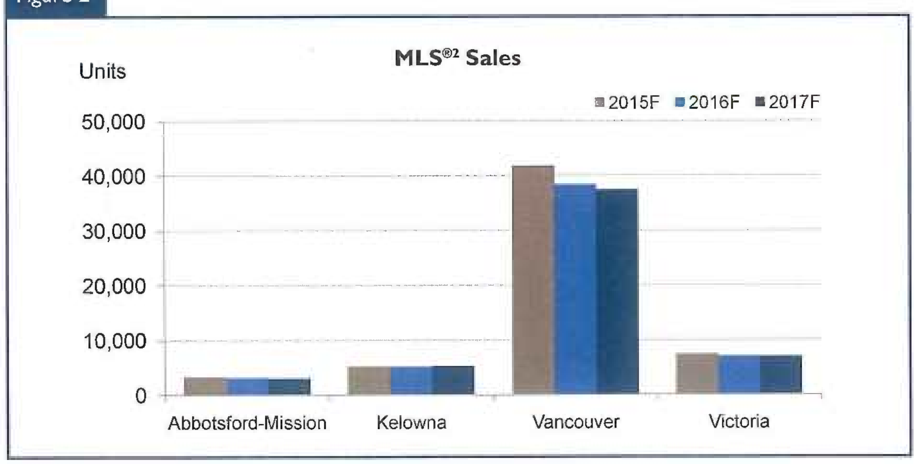


Figure 2



Overview[1]

- Housing starts in British Columbia are forecast to remain relatively stable, ranging between 25,500 to 34,100 units in 2016 with a point forecast of 30,800 units. In 2017, housing starts are forecast to range between 24,300 and 35,500 units, with a point forecast of 29,900 units.
- Multiple Listings Service (MLS®) sales are forecast to range from 82,300 to 102,700 transactions in 2016 and between 74,500 to 104,500 transactions in 2017, compared to a projected 99,000 in 2015.
- The MLS® average price is forecast to be between $594,600 and $668,000 in 2016, edging higher to $577,700 to $699,700 in 2017, compared to a projected $624,000 in 2015.

[1] The forecasts included in this document are based on information available as of September 28, 2015.

Economic Outlook

The British Columbia economy is forecast to expand in 2016 and 2017. Population-driven demand for goods and services will contribute to growth in consumer spending. An expected pick up in the pace of US economic growth, coupled with a low-valued Canadian dollar relative to the US dollar, will help to grow British Columbia exports, offsetting weaker export demand from the Asia-Pacific region. The lower dollar is also expected to grow US tourism in the province. Low oil prices are expected to a have a small net positive impact on the British Columbia economy, as consumers and businesses benefit from lower transportation costs, and interest rates remain relatively low and stable.

Projected population growth of just over one per cent per year is expected to add to demand for ownership and rental housing. People moving to BC from other countries will be the main source of population growth; most will settle in the Lower Mainland. With a low unemployment rate rivaling Alberta, job opportunities will attract people to BC from other provinces, adding to the population in all parts of the province. Net interprovincial migration is forecast to add about 23,000 people to total population between 2015 through 2017. In addition, the movement of people within the province will generate turnover in the housing stock, fuelling resale activity.

Mortgage rates are expected to continue trending close to current levels, supporting housing demand.

Mortgage rates		
1 Year	Q3 2015	2.90
	Change from Q3 2014	-0.24
	2014	3.14
	2015 (F)	2.60 to 3.30
	2016 (F)	3.00 to 3.80
	2017 (F)	3.90 to 4.80
5 Year	Q3 2015	4.65
	Change from Q3 2014	-0.14
	2014	4.88
	2015 (F)	4.10 to 5.20
	2016 (F)	4.70 to 6.00
	2017 (F)	5.10 to 6.50

Source: Bank of Canada, CMHC Forecast
NOTE: Mortgage rate forecast is based on Q3 2015 data

However, consistent with the view of Canadian economic forecasters, CMHC expects interest rates to begin to rise moderately from current levels late in 2016, contributing to a modest slowdown in housing markets.

Housing Market Outlook

Single-detached home starts are expected to range from 9,000 to 11,600 units in 2016 and between 8,100 to 11,500 units in 2017, with the broader range reflecting increased downside risk as mortgage interest rates rise. However, builders are expected to respond to increased demand for new homes this year and next, as rising prices for resale homes attract more buyers to the new home market. Single-detached home starts will get a boost from replacement housing as rising land values and an aging housing stock result in new residential construction. As well, laneway housing will add to the number of single-detached home starts.

Multiple-family home starts are forecast to maintain a relatively stable level compared to the past decade, although some increase is expected as homebuyers shift to less-expensive housing types as mortgage interest rates rise. Low rental vacancy rates in the province's larger centres are expected to support further development of multiple-unit rental projects. Multiple-family home starts are forecast to range between 16,500 and 22,500 units in 2016. A wider range is expected in 2017, with some upside risk.

MLS® sales are forecast to range from 82,300 to 102,700 transactions in 2016 and between 74,500 to 104,500 transactions in 2017. Higher levels of turnover will reflect increased migration flows and higher projected employment levels.

Sellers' resale market conditions are expected to prevail in most housing markets within British Columbia, pointing to price gains. The average home price has been influenced by compositional changes during the past few years. A rising share of higher-priced home sales in Vancouver and a rising share of Vancouver sales out of the BC total, will continue to put upward pressure on the provincial average price. Gradually rising mortgage interest rates in late 2016 and 2017 may shift home sales to less expensive home types, dampening price growth. The MLS® average price is forecast to be between $594,600 and $668,000 in 2016, edging higher to $577,700 to $699,700 in 2017.

B.C. Region Economic and Housing Indicators

		Labour Market				Housing Market				
		Emp. Growth SA[2] (%)	Unemp. Rate SA[2] (%)	Average Weekly Earnings ($)		Total Starts	Single-Detached Starts	Multiple Starts	MLS® Sales	MLS® Average Price[3] ($)
Kamloops	Q2 2015	n/a	n/a	n/a	Q2 2015	155	96	59	504	$400,362
	Q2 2014	n/a	n/a	n/a	Q2 2014	113	89	24	520	$390,587
	Change[1]	-	-	-	% Change	37.2	7.9	145.8	-3.1	2.5
Nanaimo	Q2 2015	n/a	n/a	n/a	Q2 2015	335	105	230	640	$394,790
	Q2 2014	n/a	n/a	n/a	Q2 2014	157	105	52	488	$363,026
	Change[1]	-	-	-	% Change	113.4	0.0	**	31.1	8.7
Prince George	Q2 2015	-8.3	7.4	n/a	Q2 2015	110	47	63	319	$285,260
	Q2 2014	4.1	6.2	n/a	Q2 2014	41	36	5	294	$278,874
	Change[1]	-12.5	1.3	-	% Change	168.3	30.6	**	8.5	2.3
Abbotsford-Mission	Q2 2015	6.5	5.4	870	Q2 2015	121	91	30	983	$373,979
	Q2 2014	-2.2	7.7	805	Q2 2014	207	53	154	767	$361,366
	Change[1]	8.7	-2.3	8.1%	% Change	-41.5	71.7	-80.5	28.2	3.5
Kelowna	Q2 2015	6.3	4.5	873	Q2 2015	338	155	183	1,722	$439,405
	Q2 2014	0.0	5.0	811	Q2 2014	336	169	167	1,578	$428,996
	Change[1]	6.3	-0.5	7.7%	% Change	0.6	-8.3	9.6	9.1	2.4
Vancouver	Q2 2015	-0.1	6.1	930	Q2 2015	5,655	1,300	4,355	12,843	$909,293
	Q2 2014	2.4	5.7	878	Q2 2014	4,732	1,147	3,585	9,873	$804,082
	Change[1]	-2.5	0.4	5.9%	% Change	19.5	13.3	21.5	30.1	13.1
Victoria	Q2 2015	-0.8	6.0	901	Q2 2015	508	159	349	2,538	$528,564
	Q2 2014	-1.9	5.5	869	Q2 2014	405	145	260	1,988	$500,247
	Change[1]	1.1	0.5	3.7%	% Change	25.4	9.7	34.2	27.7	5.7
B.C.	June 15	1.0	5.8	917	Q2 2015	8,506	2,783	5,723	31,420	$632,914
	June 14	0.8	6.1	875	Q2 2014	7,276	2,534	4,742	25,448	$561,217
	Change[1]	0.2	-0.3	4.8%	% Change	16.9	9.8	20.7	23.5	12.8
CANADA	June 15	1.0	6.8	919	Q2 2015	52,248	19,284	32,964	164,550	$451,499
	June 14	0.5	7.0	894	Q2 2014	53,281	21,494	31,787	152,884	$413,790
	Change[1]	0.5	-0.2	2.8%	% Change	-1.9	-10.3	3.7	7.6	9.1

MLS® is a registered trademark of the Canadian Real Estate Association (CREA).

[1] Changes to the Unemployment Rate and Employment Growth represent the ***absolute*** difference between current rates and the rates for the same period in the previous year.

[2] Seasonally adjusted Labour Force data is not available for Kamloops, Nanaimo, Prince George, and Kelowna, therefore, raw data was used.

[3] MLS® Average Price for Prince George, Nanaimo, and Kamloops is for single-detached units only

Source: Statistics Canada (CANSIM), CMHC (Starts and Completions Survey), CREA

"SA" means Seasonally Adjusted

British Columbia Housing Market Outlook (units and percentage change)	2010	2011	2012	2013	2014	2015(F)	2016(F)	2017(F)
Housing Starts:								
Single	11,462	8,867	8,333	8,522	9,569	10,200	10,400	9,900
%	45.2	-22.6	-6.0	2.3	12.3	6.6	2.0	-4.8
Multiple	15,017	17,533	19,132	18,532	18,787	21,100	20,400	20,000
%	83.5	16.8	9.1	-3.1	1.4	12.3	-3.3	-2.0
Total	26,479	26,400	27,465	27,054	28,356	31,300	30,800	29,900
%	64.7	-0.3	4.0	-1.5	4.8	10.4	-1.6	-2.9
Existing Home Markets:								
MLS® Sales	74,640	76,721	67,637	72,936	84,049	99,000	91,500	89,500
%	-12.2	2.8	-11.8	7.8	15.2	17.8	-7.6	-2.2
MLS® Average Price	505,178	561,304	514,836	537,414	568,405	624,000	636,300	646,700
%	8.5	11.1	-8.3	4.4	5.8	9.8	2.0	1.6

British Columbia Housing Market Outlook (units and percentage change)	2015Q1	2015Q2	2015Q3 (F)	2015Q4 (F)	2016Q1 (F)	2016Q2 (F)	2016Q3 (F)	2016Q4 (F)	2017Q1 (F)	2017Q2 (F)	2017Q3 (F)	2017Q4 (F)
Housing Starts:												
Single	10,321	10,453	10,100	9,900	10,200	10,400	10,500	10,500	10,200	9,900	9,800	9,700
%	-1.1	1.3	-3.4	-2.0	3.0	2.0	1.0	0.0	-2.9	-2.9	-1.0	-1.0
Multiple	19,807	22,676	21,700	20,100	20,300	20,600	20,400	20,300	20,000	20,100	20,000	19,900
%	7.1	14.5	-4.3	-7.4	1.0	1.5	-1.0	-0.5	-1.5	0.5	-0.5	-0.5
Total	30,128	33,129	31,800	30,000	30,500	31,000	30,900	30,800	30,200	30,000	29,800	29,600
%	4.2	10.0	-4.0	-5.7	1.7	1.6	-0.3	-0.3	-1.9	-0.7	-0.7	-0.7
Existing Home Markets:												
MLS® Sales	94,064	101,756	103,000	97,000	95,100	92,800	90,000	88,100	88,700	89,500	89,700	90,100
%	6.5	8.2	1.2	-5.8	-2.0	-2.4	-3.0	-2.1	0.7	0.9	0.2	0.4
MLS® Average Price	610,538	626,725	633,000	625,000	629,000	632,000	640,000	645,000	647,000	649,000	647,000	644,000
%	4.8	2.7	1.0	-1.3	0.6	0.5	1.3	0.8	0.3	0.3	-0.3	-0.5

MLS® is a registered trademark of the Canadian Real Estate Association (CREA).

Source: CMHC (Starts and Completions Survey), CREA

All data in this table, except the MLS (R) average price, is seasonally adjusted at annual rates. The MLS (R) average price data is actual.

B.C. Region - Housing Forecast Ranges									
	2015			2016			2017		
	Point Forecast	High Forecast	Low Forecast	Point Forecast	High Forecast	Low Forecast	Point Forecast	High Forecast	Low Forecast
British Columbia									
Housing Starts	31,300	33,100	27,900	30,800	34,100	25,500	29,900	35,500	24,300
Multiple	21,100	22,100	18,900	20,400	22,500	16,500	20,000	24,000	16,200
Single	10,200	11,000	9,000	10,400	11,600	9,000	9,900	11,500	8,100
MLS® Sales	99,000	103,400	94,600	91,500	102,700	82,300	89,500	104,500	74,500
MLS® Average Price ($)	624,000	642,700	613,300	636,300	668,000	594,600	646,700	699,700	577,700
Canada									
Housing Starts	186,900	212,000	162,000	178,150	203,000	153,000	173,650	199,000	149,000
Multiple	119,200	140,000	98,000	108,850	129,000	89,000	108,725	130,000	88,000
Single	67,700	75,000	60,000	69,300	78,000	61,000	64,925	74,000	56,000
MLS® Sales	494,700	546,000	444,000	479,500	534,000	425,000	476,000	536,000	416,000
MLS® Average Price ($)	437,700	459,000	417,000	443,300	466,000	420,000	449,600	475,000	424,000

Sources : CMHC

MLS® is a registered trademark of the Canadian Real Estate Association (CREA).

B.C. Region Housing Forecast - New Construction

	Housing Starts	2014	2015(F)*	% chg (2014/ 2015)	2016(F)*	% chg (2015/ 2016)	2017(F)*	% chg (2016/ 2017)	YTD 2015**	YTD 2014**	% chg (2014/ 2015)
Kamloops	Single-Detached	281	260	-7.5	250	-3.8	240	-4.0	129	108	19.4
	Multiple	237	250	5.5	250	0.0	230	-8.0	78	120	-35.0
	Total	518	510	-1.5	500	-2.0	470	-6.0	207	228	-9.2
Nanaimo	Single-Detached	318	375	17.9	350	-6.7	325	-7.1	199	164	21.3
	Multiple	347	425	22.5	400	-5.9	400	0.0	298	102	192.2
	Total	665	800	20.3	750	-6.3	725	-3.3	497	266	86.8
Prince George	Single-Detached	133	145	9.0	145	0.0	160	10.3	81	53	52.8
	Multiple	25	85	240.0	65	-23.5	60	-7.7	66	5	**
	Total	158	230	45.6	210	-8.7	220	4.8	147	58	153.4
Abbotsford-Mission	Single-Detached	251	350	39.4	290	-17.1	280	-3.4	137	96	42.7
	Multiple	248	340	37.1	380	11.8	180	-52.6	133	160	-16.9
	Total	499	690	38.3	670	-2.9	460	-31.3	270	256	5.5
Kelowna	Single-Detached	695	600	-13.7	575	-4.2	585	1.7	273	308	-11.4
	Multiple	616	780	26.6	825	5.8	835	1.2	278	237	17.3
	Total	1,311	1,380	5.3	1,400	1.4	1,420	1.4	551	545	1.1
Vancouver	Single-Detached	4,374	4,600	5.2	4,700	2.2	4,500	-4.3	2,254	1,998	12.8
	Multiple	14,838	15,700	5.8	16,000	1.9	15,600	-2.5	7,684	7,107	8.1
	Total	19,212	20,300	5.7	20,700	2.0	20,100	-2.9	9,938	9,105	9.1
Victoria	Single-Detached	551	625	13.4	600	-4.0	575	-4.2	303	260	16.5
	Multiple	764	1,325	73.4	1,300	-1.9	1,300	0.0	681	336	102.7
	Total	1,315	1,950	48.3	1,900	-2.6	1,875	-1.3	984	596	65.1

Source: CMHC (Starts and Completions Survey)
(F) = CMHC Forecast
* Although point forecasts are provided in this table, please refer to the "Housing Forecast Range" table to get the relevant ranges.
** YTD = January - June

B.C. Region Housing Forecast - Resale Market											
		2014	2015(F)*	% chg (2014/ 2015)	2016(F)*	% chg (2015/ 2016)	2017(F)*	% chg (2016/ 2017)	YTD 2015**	YTD 2014**	% chg (2014/ 2015)
Kamloops[1]	MLS® Sales(#)	1,735	1,750	0.9	1,780	1.7	1,800	1.1	851	830	2.5
	MLS® Avg. Price ($)	384,433	404,000	5.1	410,000	1.5	420,000	2.4	400,291	383,243	4.4
Nanaimo[1]	MLS® Sales(#)	1,686	1,950	15.7	1,900	-2.6	1,825	-3.9	1,021	844	21.0
	MLS® Avg. Price ($)	370,766	390,000	5.2	400,000	2.6	406,000	1.5	391,397	362,958	7.8
Prince George[1]	MLS® Sales(#)	1,285	1,260	-1.9	1,300	3.2	1,280	-1.5	486	459	5.9
	MLS® Avg. Price ($)	271,581	281,000	3.5	290,000	3.2	298,000	2.8	282,048	275,344	2.4
Abbotsford-Mission	MLS® Sales(#)	2,592	3,300	27.3	3,220	-2.4	3,080	-4.3	1,611	1,316	22.4
	MLS® Avg. Price ($)	353,683	371,600	5.1	383,500	3.2	394,000	2.7	370,443	348,882	6.2
Kelowna	MLS® Sales(#)	4,886	5,200	6.4	5,200	0.0	5,300	1.9	2,735	2,378	15.0
	MLS® Avg. Price ($)	425,996	445,000	4.5	455,000	2.2	460,000	1.1	429,994	425,651	1.0
Vancouver	MLS® Sales(#)	33,693	41,800	24.1	38,400	-8.1	37,400	-2.6	22,031	16,944	30.0
	MLS® Avg. Price ($)	812,653	887,600	9.2	914,100	3.0	933,200	2.1	894,493	811,084	10.3
Victoria	MLS® Sales(#)	6,371	7,400	16.2	7,050	-4.7	7,000	-0.7	4,086	3,256	25.5
	MLS® Avg. Price ($)	496,473	515,500	3.8	534,500	3.7	547,000	2.3	515,711	496,236	3.9

MLS® is a registered trademark of the Canadian Real Estate Association (CREA).

[1] MLS® Average Price for Prince George, Nanaimo, and Kamloops is for single-detached units only

Source: CREA

(F) = CMHC Forecast

* Although point forecasts are provided in this table, please refer to the "Housing Forecast Range" table to get the relevant ranges.

** YTD = January - June

B.C. Region Housing Forecast - Rental Market												
	Vacancy Rate				Average Rent 1-Bedroom Units				Average Rent 2-Bedroom Units			
	Oct 2014	Oct 2015(F)	Oct 2016(F)	Oct 2017(F)	Oct 2014	Oct 2015(F)	Oct 2016(F)	Oct 2017(F)	Oct 2014	Oct 2015(F)	Oct 2016(F)	Oct 2017(F)
Kamloops	3.9	3.7	3.9	3.8	739	760	780	795	866	880	895	910
Nanaimo	4.4	3.0	3.2	3.5	700	715	730	745	812	830	845	860
Prince George	3.0	3.2	3.8	4.4	647	655	660	670	771	785	800	815
Abbotsford-Mission	3.1	2.9	2.7	2.7	684	694	705	715	835	850	865	881
Kelowna	1.0	1.5	1.8	2.0	788	802	817	832	980	995	1010	1030
Vancouver	1.0	0.8	1.0	1.2	1,038	1065	1095	1120	1,311	1350	1390	1420
Victoria	1.5	1.4	1.0	1.2	849	865	885	905	1,095	1115	1140	1165
Canada[1]	2.8	3.1	3.3	3.4	n/a	n/a	n/a	n/a	955	970	984	995

Source: CMHC Fall Rental Market Survey
(F) = CMHC Forecast
[1] All centres 100,000+

CMHC—HOME TO CANADIANS

Canada Mortgage and Housing Corporation (CMHC) has been Canada's national housing agency for more than 65 years.

Together with other housing stakeholders, we help ensure that the Canadian housing system remains one of the best in the world. We are committed to helping Canadians access a wide choice of quality, environmentally sustainable and affordable housing solutions that will continue to create vibrant and healthy communities and cities across the country.

For more information, visit our website at www.cmhc.ca or follow us on Twitter, YouTube and Flickr.

You can also reach us by phone at 1-800-668-2642 or by fax at 1-800-245-9274.

Outside Canada call 613-748-2003 or fax to 613-748-2016.

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Attachment 38.1

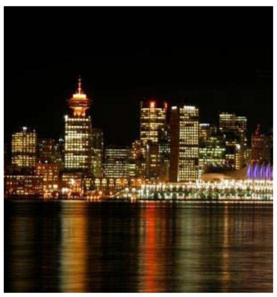
BC Hydro
Schedule 1101 - Residential Service

	1-Apr-94	1-Apr-04	1-Jul-06	1-Feb-07	1-Apr-08	1-Oct-08	1-Apr-09	1-Apr-10	1-May-11	1-Apr-12	1-Apr-13	1-Apr-14	1-Apr-15
Basic Charge per period (per 2 months - Apr/08 - per day)	$ 6.92	$ 7.26	$ 7.60	$ 7.38	$ 0.1241	$ 0.1238	$ 0.1264	$ 0.1341	$ 0.1448	$ 0.1505	$ 0.1527	$ 0.1664	$ 0.1764
All kW.h per period	$ 0.0577	$ 0.0605	$ 0.0633	$ 0.0615	0.0629	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Step 1 - First 1,350 kW.h per two months	n/a	n/a	n/a	n/a	n/a	$ 0.0546	$ 0.0591	$ 0.0627	$ 0.0667	$ 0.0680	$ 0.0690	$ 0.0752	$ 0.0797
Step 2 - Additional kW.h per two months	n/a	n/a	n/a	n/a	n/a	$ 0.0721	$ 0.0827	$ 0.0878	$ 0.0962	$ 0.1019	$ 0.1034	$ 0.1127	$ 0.1195

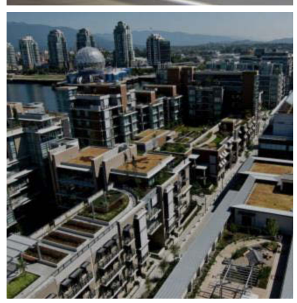
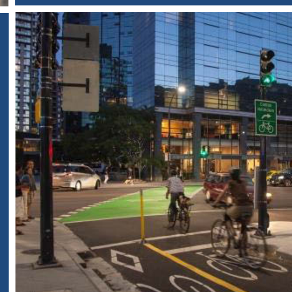
**Rates are exclusive of the applicable deferral account rate riders.*

Attachment 44.1

Renewable City Strategy
Executive Summary




November 2015

CITY OF
VANCOUVER

Executive Summary :: Achieving 100% Renewable Energy for Vancouver

Imagine a city where jobs and businesses are diverse and economically strong; where homes and offices have clean and comfortable environments that are less expensive to heat and cool; where the transportation system is abundant and efficient, a city that supports a thriving economy while improving affordability and provides citizens the opportunity to be healthy and mobile.
Imagine a city powered only by renewable energy.

Renewable Energy is energy that is naturally replenished as it is used

Target 1: *Derive 100% of the energy used in Vancouver from renewable sources before 2050*
Target 2: *Reduce Greenhouse Gas emissions by at least 80% below 2007 levels before 2050*

Geographic Scope: The geographic scope of the *Renewable City Strategy* covers the area within the City limits, and any facilities owned or operated by the City of Vancouver outside those limits.
Emissions Scope: The *Renewable City Strategy* will track emissions in accordance with the most stringent international reporting standards (currently the *Global Protocol for Community-Scale Greenhouse Gas Emission Inventories*).

Strategic Approach

1. **Reduce energy use**
   Advance energy conservation and efficiency programs which are the most cost-effective way to a renewable energy future.
2. **Increase the use of renewable energy**
   Switch to renewable forms of energy that are already available to us, and make improvements to our existing infrastructure to use it to its fullest potential.
3. **Increase the supply of renewable energy**
   Increase the supply of renewable energy and build new renewable energy infrastructure.

Primed for Success

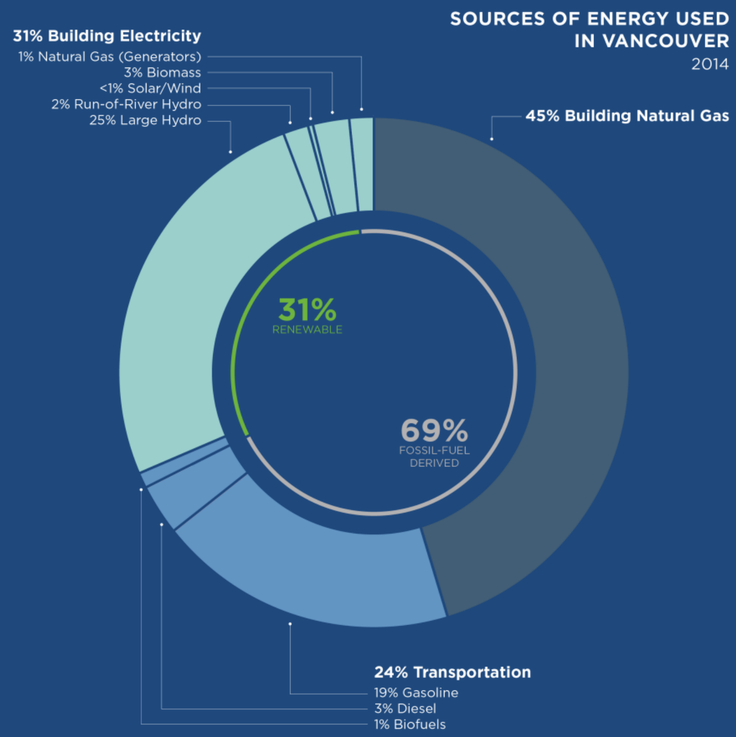
Vancouver has all the conditions needed to successfully derive 100% of its energy from renewable sources before 2050. Vancouver is building on 25 years of action and success to tackle climate change for the benefit of all who live in, work in and visit Vancouver, and for the benefit of the world. Vancouver, a city of 605,000 people and an area of 115 *sq. km*, is already a world leader in the development of complete, compact, and livable communities that already have greenhouse gas emissions per person amongst the lowest in the developed world. Serviced by an clean and reliable electrical system, which also powers much of the city's transit system, Vancouver is primed to capitalize on the electrification of both its buildings and its transportation system. Vancouver's brand, valued at US$31bn when measured by investment, reputation and performance, demonstrates the economic importance of existing in harmony with nature.

The Opportunity

The technological and business transformation of energy efficiency, conservation and management coupled with new renewable energy generation is set to define the economy of the future. The *Renewable City Strategy* positions Vancouver to increase its economic diversity for a stronger, more resilient economy. A healthy environment is essential to attracting and retaining the very best minds, establishing Vancouver as an innovation hub with high and inclusive employment, and positioning Vancouver in the vanguard of long-term economic stability and success. The City of Vancouver can be the catalyst for change through its own internal operations, as well as public pilots and demonstrations. Ensuring that the city's neighbourhoods, communities, buildings, transportation system, businesses and individuals embrace renewable energy will mean a better, healthier quality of life for Vancouverites today and into the future.

Energy Use in Vancouver Today

Vancouver's energy use is currently 31% renewable, with the fossil fuel fraction dominated by natural gas for space heat and hot water, and gasoline for personal and light-duty vehicle use. Vancouver's energy use and resulting greenhouse gas emissions, are dominated by buildings and transportation. These two sectors are the primary focus of the *Renewable City Strategy*.



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B.1 New buildings to be zero-emission by 2030

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- B.1.3 Incentivize and streamline the development of exemplary buildings
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- B.2.4 Facilitate modest retrofits through structured guidance and the provision of incentives
- B.2.5 Increase renewable energy use by large energy consumers

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- B.3.2 Enable the conversion of the downtown and hospital steam systems from natural gas to renewable energy
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- B.3.4 Continue to enforce, and update as required, building and renewable energy supply policies that support neighbourhood renewable energy systems

B.4 Ensure grid supplied electricity is 100% renewable

- B.4.1 Partner with utilities to increase the supply of renewable energy
- B.4.2 Partner with utilities to implement a smart grid that meets Vancouver's energy needs

A Vision for Vancouver's Buildings in 2050

By 2050, about 40% of Vancouver's buildings will have been replaced and built to the carbon-neutral standards set out in the *Greenest City 2020 Action Plan* or to zero-emission standards which will have come into effect before 2030. Of the buildings which remain there will be an even split between those built to current standards and those built to standards pre-dating 2010. The vast majority of buildings that have not been built to zero-emission standards will have undergone deep retrofits to bring their energy performance up to the standards expected of new construction, or have been connected to the one of Vancouver's renewable neighbourhood energy systems. These changes will cut city-wide building energy use by about 30% compared to 2014.

Current business-as-usual energy use with existing City and Provincial policies would likely mean an increase in city-wide electricity use by 2050 of approximately 10% over 2014, with large amounts of fossil-fuel-derived energy remaining. The *Renewable City Strategy* would lead to an increase in electricity use of about 20% by 2050 over 2014 levels, but would in the process eliminate Vancouver's need for fossil fuels.

Building performance improvements and the expansion of neighbourhood renewable energy systems that can provide heating and cooling will limit increases in electrical demand. There will be only minimal need for large electrical generation and transmission infrastructure investments – British Columbia's electrical grid can be capitalized upon and optimized to meet demand with only modest generation additions. The use of on-site power generation from solar or the meeting of heating needs through air-source heat pumps or geoexchange systems will further limit the need for new electrical generation. For those buildings that cannot be brought to perform to zero-emission standards and that cannot be connected to renewable neighbourhood energy systems, biomethane will be used to meet heating needs, although this need is expected to be minimal and biomethane will play a more significant role in the transportation system as an energy-rich mobile fuel.

The incremental electrical demand increase over business-as-usual will in part be due to the electrification of personal transportation. Since typical daily commutes are short in Vancouver, and the need for personal vehicle use will decline substantially by 2050, vehicle electrical demand will constitute only about 5% of total annual city-wide electrical demand, with this deamdn required to be met through home and work-place charging infrastructure. New smart-grid technologies will manage electrical distribution, on-site generation, and electric vehicle charging.

Renewably Powered Transportation Priorities

T.1 Use land-use and zoning policies to develop complete compact communities and complete streets that encourage active transportation and transit

- T.1.1 Foster land use as a tool to improve transportation consistent with the direction established in *Transportation 2040*
- T.1.2 Enhance and accelerate the development of complete streets and green infrastructure
- T.1.3 Enhance the pedestrian network according to the direction established in *Transportation 2040*
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- T.1.5 Use parking policies to support sustainable transportation choices and efficient use of our street network
- T.1.6 Optimize the road network to manage congestion, improve safety, and prioritize green transportation

T.2 Improve transit services as set out in *Transportation 2040*

- T.2.1 Extend the Millennium Line in a tunnel under Broadway
- T.2.2 Improve frequency, reliability, and capacity across the transit network
- T.2.3 Develop a transit supportive public realm with improved multimodal integration and comfortable waiting areas
- T.2.4 Work with the transit authority and other partners to transition fossil fuel powered transit vehicles to renewable energy

T.3 Transition light-duty vehicles (cars and light trucks) to be predominantly electric, plug-in hybrid or sustainable biofuel powered

- T.3.1 Develop vehicle and fuel standards to support renewably powered vehicles
- T.3.2 Develop supporting infrastructure that meets the needs of renewably powered vehicles

T.4 Develop car-sharing and regional mobility pricing to encourage rational journey choice

- T.4.1 Support increased car-sharing and the uptake of renewably powered vehicles in car-sharing fleets.
- T.4.2 Advocate for comprehensive regional mobility pricing

T.5 Better manage commercial vehicle journeys and transition heavy-duty (commercial) vehicles to sustainable biofuels, biomethane, hydrogen and electricity

T.5.1 Improve the delivery of commercial freight, goods, and services according the direction set in *Transportation 2040*
T.5.2 Work with fleet operators and contractors to transition to renewably powered vehicles

A Vision for Vancouver's Transportation System in 2050

Vancouver will continue its efforts to build a city that is compact and complete, allowing most people to meet their daily needs through walking, cycling, and transit. Longer journeys will be made on transit that is predominantly electrified, complemented by renewable fuels like sustainable biofuel, biomethane, or hydrogen. The number of people living and working in the city will grow significantly by 2050, and while the number of private vehicles per person could decline by as much as 15%, the total number is expected to increase by 15%. Even with this growth, the actions outlined in the *Renewable City Strategy* - including thoughtful land use planning and infrastructure investments that improve green transportation options - could reduce total annual vehicle kilometres travelled by 20% over 2014.

The *Renewable City Strategy* priorities will help transition private vehicles to using only renewable energy sources. By 2050 about 25% of Vancouver's personal vehicles would be electric using renewably generated electricity, 45% plug-in hybrids using renewable electricity and sustainable biofuels, and the remainder conventional hybrid vehicles running on sustainable biofuels. The compact nature of Vancouver means daily commutes are short enough to allow the vast majority of plug-in hybrid journeys to use only the vehicle's battery. Given the anticipated growth in both electric and plug-in hybrid vehicles, it will be critical to provide charging infrastructure at home, work, and on-the-go locations. The effect of autonomous cars on our transportation system is expected to be marked, although it is unclear if the effect will in aggregate be positive or negative.

As fewer people drive for personal trips, the proportion of transportation energy attributable to commercial vehicles will increase. Less important than the number of commercial vehicles is the distance they travel and the weight of goods they haul. Improving how goods, freight, and services are provided will be paramount, although it is as yet unclear if electrification, biofuels, biomethane or hydrogen will dominate heavy-duty vehicle types.

City Services Renewable Energy Priorities

The City of Vancouver can catalyze change by being a leader in the use of renewable energy in its own operations and empowering change through the full array or services it provides; to do this:

S.1 The City will adopt a comprehensive approach to the consideration of climate change as part of its service planning

S.2 The City will adopt a comprehensive approach to pricing carbon emissions for municipal operations

S.3 The City will develop a framework to assess how City enabling tools may be used to support the transition to 100% renewable energy

S.4 The City commits to keep abreast of financing mechanisms available that enable the delivery of renewable energy technology and other green infrastructure

Economic Opportunity Priorities

The Renewable City Strategy provides a significant economic opportunity for Vancouver that will be capitalized on through:

E.1 Support innovators through business and technology research, incubation, acceleration, and demonstration.

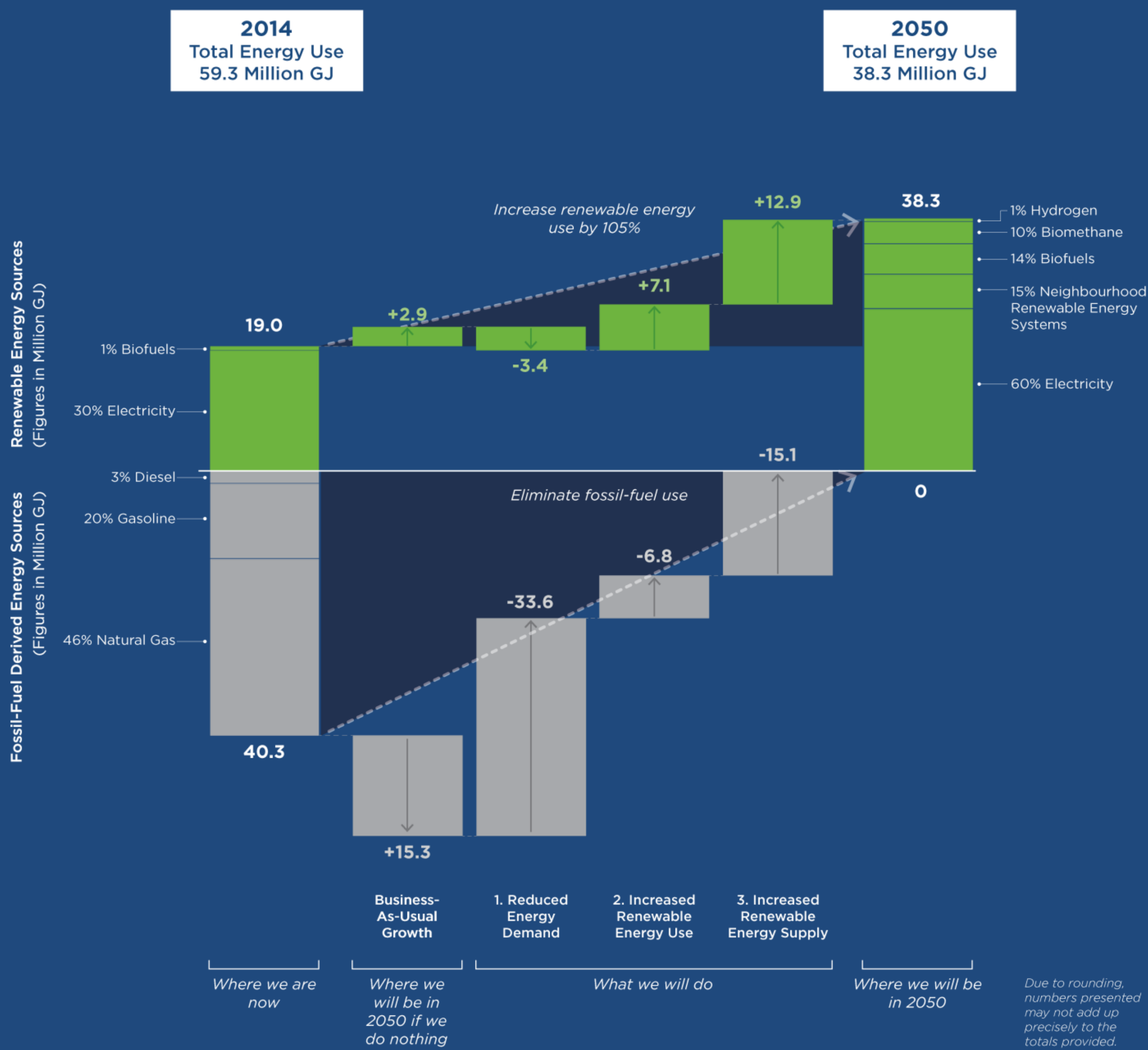
E.2 Actively work with businesses to increase the use of renewable energy

E.3 Target key events and organizations that represent clean tech and renewable energy to strengthen Vancouver's economy

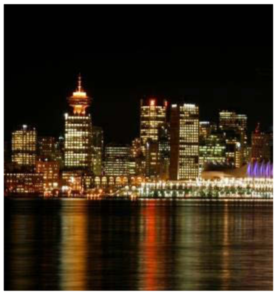
E.4 Attract 'green capital' and enable more innovative financing mechanisms for clean and renewable businesses

Vancouver's Potential Energy System Transformation

Below are the modelled effects of implementing the *Renewable City Strategy*. The cumulative effect of the strategy is to reduce total energy use by one third over 2014 levels, saving 21 million GJ of energy a year, a reduction over business-as-usual energy demand of more than 50%, saving 39 million GJ of energy annually. Improvements in building performance, reductions in personal vehicle use through active transport, and improvements in vehicle efficiency account for 45% of total city-wide energy system changes. The increased use of existing renewable energy sources like the expansion of neighbourhood renewable energy systems, increased transit use and the expansion of car-sharing could account for about 20% of city-wide energy use changes. Finally, the increase of renewable energy supply through new neighbourhood renewable energy systems and the use of biofuels, biomethane and hydrogen could account for 35% of changes in Vancouver's energy system.



Renewable City Strategy



November 2015

CITY OF
VANCOUVER

Executive Summary :: Achieving 100% Renewable Energy for Vancouver

Imagine a city where jobs and businesses are diverse and economically strong; where homes and offices have clean and comfortable environments that are less expensive to heat and cool; where the transportation system is abundant and efficient, a city that supports a thriving economy while improving affordability and provides citizens the opportunity to be healthy and mobile.
Imagine a city powered only by renewable energy.

Renewable Energy is energy that is naturally replenished as it is used

Target 1: *Derive 100% of the energy used in Vancouver from renewable sources before 2050*
Target 2: *Reduce Greenhouse Gas emissions by at least 80% below 2007 levels before 2050*

Geographic Scope: The geographic scope of the *Renewable City Strategy* covers the area within the City limits, and any facilities owned or operated by the City of Vancouver outside those limits.
Emissions Scope: The *Renewable City Strategy* will track emissions in accordance with the most stringent international reporting standards (currently the *Global Protocol for Community-Scale Greenhouse Gas Emission Inventories*).

Strategic Approach

1. **Reduce energy use**
   Advance energy conservation and efficiency programs which are the most cost-effective way to a renewable energy future.
2. **Increase the use of renewable energy**
   Switch to renewable forms of energy that are already available to us, and make improvements to our existing infrastructure to use it to its fullest potential.
3. **Increase the supply of renewable energy**
   Increase the supply of renewable energy and build new renewable energy infrastructure.

Primed for Success

Vancouver has all the conditions needed to successfully derive 100% of its energy from renewable sources before 2050. Vancouver is building on 25 years of action and success to tackle climate change for the benefit of all who live in, work in and visit Vancouver, and for the benefit of the world. Vancouver, a city of 605,000 people and an area of 115 *sq. km*, is already a world leader in the development of complete, compact, and livable communities that already have greenhouse gas emissions per person amongst the lowest in the developed world. Serviced by a clean and reliable electrical system, which also powers much of the city's transit system, Vancouver is primed to capitalize on the electrification of both its buildings and its transportation system. Vancouver's brand, valued at US$31bn when measured by investment, reputation and performance, demonstrates the economic importance of existing in harmony with nature.

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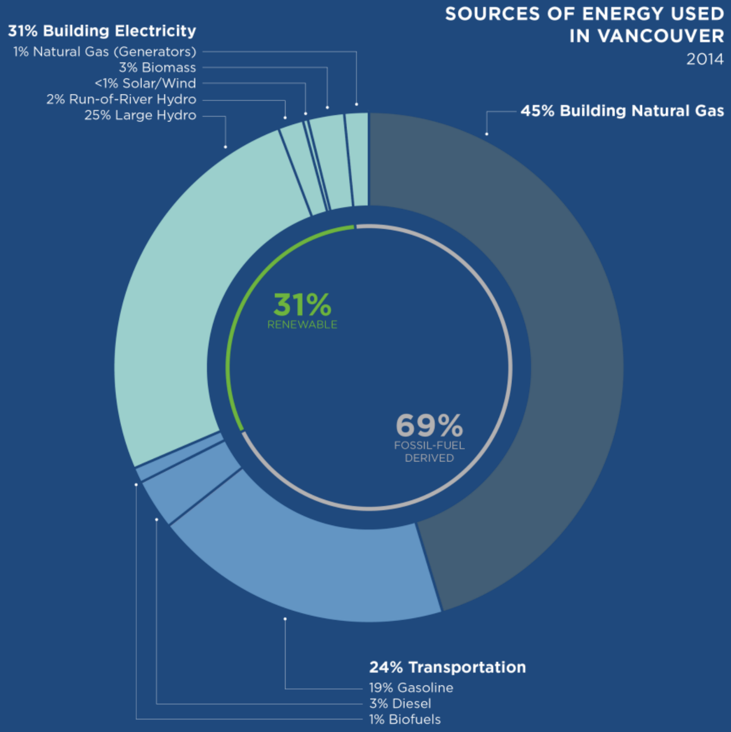

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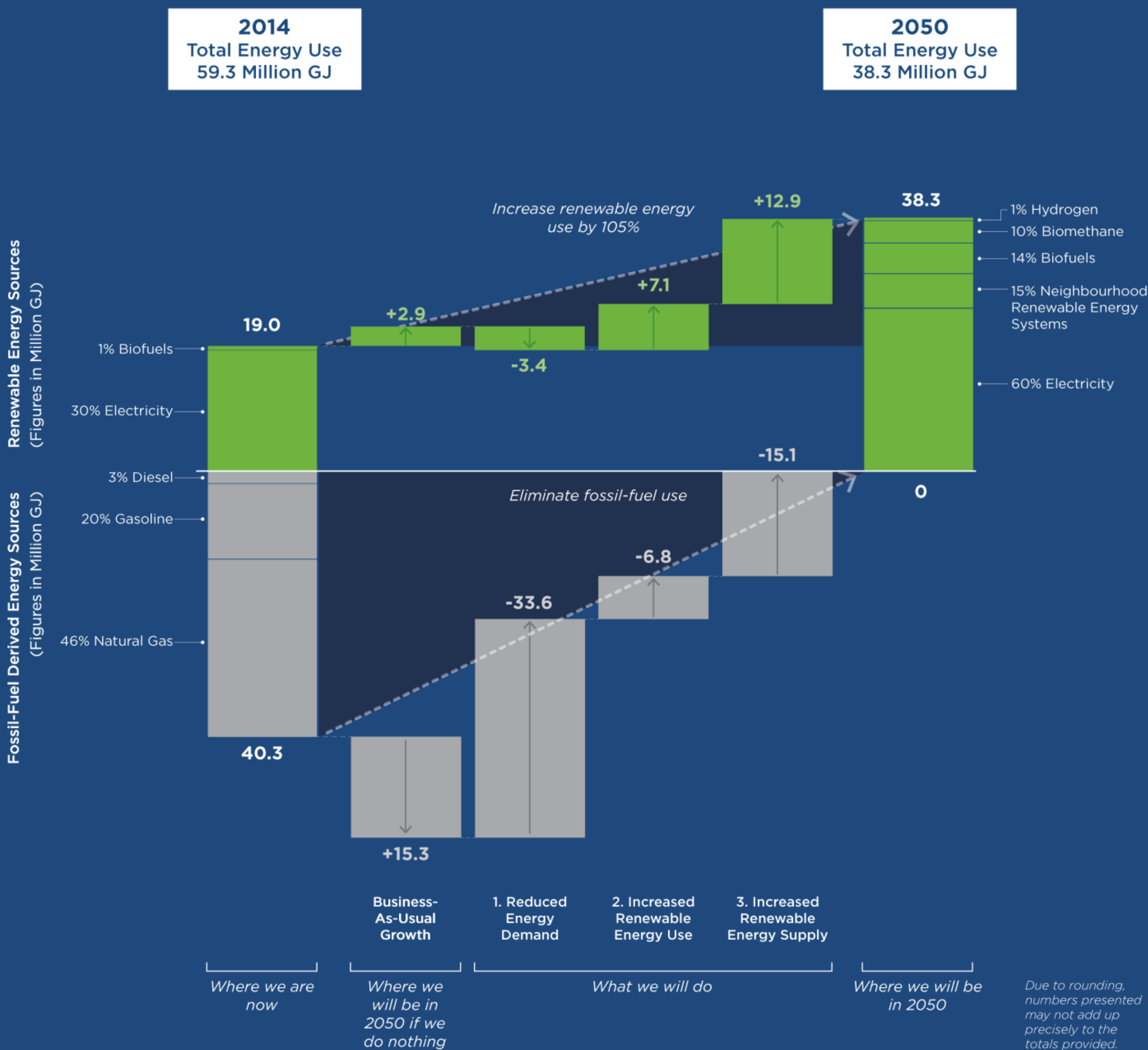

How to Read the Strategy

The Renewable City Strategy provides a vision and direction to using only renewable energy sources to meet Vancouver's energy needs. It is not intended to be prescriptive or provide a detailed roadmap. The strategy is structured to provide an overview of what the 100% renewable energy commitment means and how it was developed, followed by some context in which the strategy must be considered, before discussing in detail the technological options and actions that can be taken to transition Vancouver's buildings and transportation to use only renewable energy. There are summary sections (on blue pages) at the start of the document and also at the front of the Building and Transportation sections. Throughout the document, reference is made to the City of Vancouver or "the City," which refers to the municipal corporation, while references to the "city" (with a lower-case "c") make reference to the community as a whole.

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Overview : Where We Are and Where We Are Going

Imagine a city where jobs and businesses are diverse and economically strong; where homes and offices have clean and comfortable environments, are less expensive to heat and cool; where the transportation system is abundant and efficient, a city that supports a thriving economy while improving affordability and provides citizens the opportunity to be healthy and mobile.
Imagine a city powered by renewable energy.

Goals and Targets

The City of Vancouver's mission statement is "to create a great city of communities that cares about its people, its environment, and the opportunities to live, work, and prosper." The *Renewable City Strategy* is at its core a strategy that focuses on these three pillars: Vancouver's people, economy, and environment. The transition to using 100% renewable energy, and the arrival at that goal, provides an opportunity to enhance each of these pillars.

People: Vancouver is defined by its residents and their diversity, ability to adapt, visionary outlook, and desire to be involved in shaping their city. Moving towards the use of 100% renewable energy provides the opportunity for communities to be more vibrant, integrated, and considerate of their impacts. The energy used in daily life through transportation choices, heating and cooling homes, and managing waste is integral to delivering the communities Vancouverites want.

Economy: The transition to the use of 100% renewable energy provides the opportunity for innovation and development of new business models, products, and technologies. Local innovation can be shared internationally, reinforcing Vancouver's leadership in environmentally responsible urban stewardship.

Environment: Evolving to a renewable-energy future provides many environmental benefits in addition to reduced greenhouse gas emissions. Concurrent benefits include better air quality, a healthier lifestyle, enhanced natural habitat, reduced pollution risk from leaks and spills, and preparation for the anticipated impacts of a changing climate such as extreme weather events.

Where Are We Now?

Known for its mild coastal climate and mountain views, Vancouver is the largest city in British Columbia and the eighth-largest city in Canada. Vancouver has an ethnically and linguistically diverse community where half its residents speak a first language other than English, and an economy that is the second-most diversified in Canda. At the time of first European contact in the late 18th century, the Musqueam, Squamish, and Tsleil-Waututh peoples lived in the area that is now Vancouver. All are Coast Salish First Nations, sharing cultural and language traits with people in the Fraser Valley and Northern Washington State, and the City of Vancouver acknowledges their unceded traditional territories.

Vancouver has grown a lot in the past 129 years and now uses over 59.3 million gigajoules (GJ) of energy a year—that's enough energy to get to the moon and back 6,500 times—and releases 2.8 million tonnes of carbon dioxide (CO_2) as a result. The focus of the *Renewable City Strategy* is on the sectors of our city that consume the most energy: buildings and transportation. Additionally, there are many other sources of greenhouse gas emissions that the City will continue to address in partnership with other stakeholders.

Of our total energy consumption in buildings and transport, about 31% is currently renewable, thanks mostly to the province's large hydroelectric generating facilities. A small portion of gasoline and diesel within BC is also regulated to come from renewable sources.

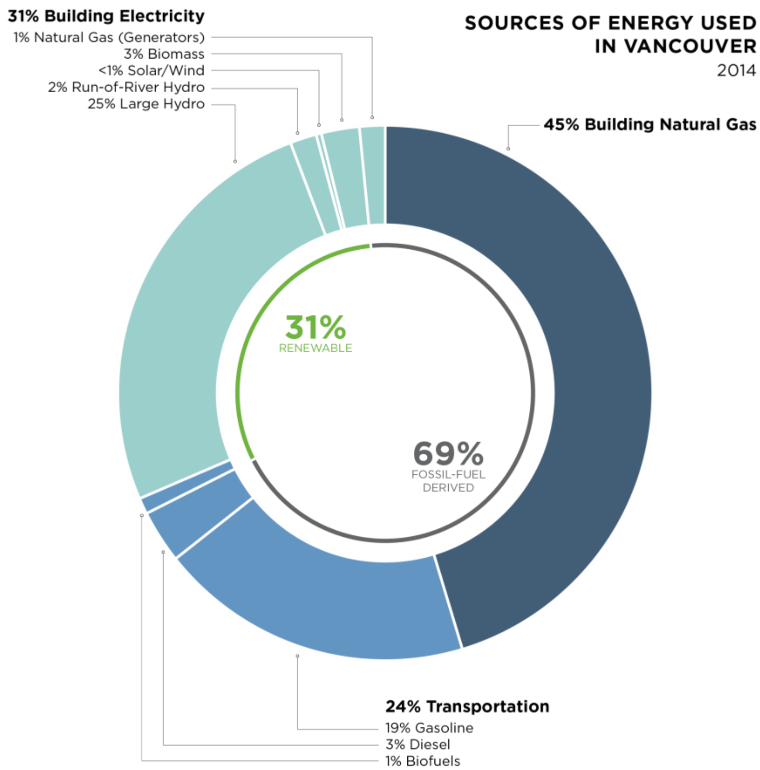


Figure 1 **- Vancouver Community Wide 2014 Energy Use (directly recorded and modelled)**

Goal

The goal of *Renewable City Strategy* is that Vancouver will become a city that uses only renewable sources of energy while respecting the principles of sustainability.

Renewable energy is energy that is naturally replenished as it is used.

Renewable energy technologies are in the ascendancy as they mature and become cost competitive, and many more new technologies are under development or yet to be realized. As long as they meet the above definition, new innovations will be considered as the *Renewable City Strategy* is updated and refined.

Transportation: Renewable energy sources for transportation include responsibly sourced and processed biofuels, hydrogen from the electrolysis of water using renewable electricity, biomethane (also called “renewable natural gas” or “biogas”) and renewable electricity.

Buildings: Renewable energy sources for buildings must typically provide heating and cooling or electricity. Electrical needs can be met by both large and small hydro projects, photovoltaics and wind; space heat can be met with biomethane, heat pumps or resistance heating using renewable electricity or renewable waste streams such as, biomethane, recycled wood and sewer heat, with geoexchange systems able to provide renewable heating and cooling.

Targets

Target 1: *Derive 100% of the energy used in Vancouver from renewable sources before 2050*
Target 2: *Reduce greenhouse gas emissions by at least 80% below 2007 levels before 2050*

Scope

Geographic Scope: The geographic scope of the *Renewable City Strategy* covers the area within the City limits, and any facilities owned or operated by the City of Vancouver outside those limits.
Emissions Scope: The *Renewable City Strategy* will track emissions in accordance with the most stringent international reporting standards (currently the Global Protocol for Community-Scale Greenhouse Gas Emission Inventories).

Almost all aspects of our daily lives require some form of energy, which generates carbon pollution in the form of greenhouse gases: energy to heat our homes and workplaces, energy to produce the food and products we consume, and fuel to transport people and goods. Much of this energy produces carbon dioxide – the most significant greenhouse gas because it is released in such large quantities. Other greenhouse gases – methane, oxides of nitrogen (NO_x), and certain industrial gases – are also released by industrial processes, agricultural activity, the manufacture of goods, and most prominently when we burn fuel.

The second target ensures that a focus on renewable energy sources does not overlook greenhouse gas emissions reductions. The dual targets ensure that the city's waste management system, responsible for about 8% of Vancouver's community emissions in 2014, is truly integrated into our energy system.

The City will take action where it has influence over Scope I emissions—those emissions that result directly from energy use, such as the use of natural gas or diesel to produce energy for buildings (of all types), in the manufacture of goods and products, or in the use of gasoline, diesel, and other fossil fuels in the transportation system for road, railway, waterborne, air and non-road vehicles. The City will also take action on Scope II emissions – those that result from the production of energy from another source, most typically electricity generated outside the city or in the production of steam in neighbourhood energy systems. Carbon emissions derived from the disposal of solid and liquid waste, as well as the combustion of compostable materials, will be addressed directly (for example, through landfill gas capture), and as inputs to the energy system (by, for example, using biomethane from landfill gas to power vehicles

The City will also continue to support reductions in energy use and greenhouse gas (GHG) emissions for Scope III emissions – those emissions that result from consumption, or "embedded emissions", such as transportation energy use outside the city, or in the production of the goods we consume, most notably food, or the buildings we construct. It should also be noted that even in a 100% renewable energy city there will still be very small amounts of fossil fuel burned, one example of which is likely to be vintage and classic cars; the number of these cars is already small and will remain immaterial to the strategy's broader goals.

Strategic Approach to the Renewable Energy Transition

The City's strategic approach to renewable energy is structured to reflect that energy efficiency and conservation measures have the largest long-term impact and are the most cost effective, and that increasing the use of existing renewable energy resources is more cost effective than building new.

1. **Reduce energy use.**
   Advance energy conservation and efficiency programs which are the most cost-effective way to a renewable energy future.
   eg. increase building insulation requirements; improve walking and cycling networks
2. **Increase the use of renewable energy.**
   Switch to renewable forms of energy that are already available to us, and make improvements to our existing infrastructure to use it to its fullest potential.
   eg. switch to an electric vehicle; expand the number of buildings connected to the Southeast False creek Neighbourhood Energy Utility
3. **Increase the supply of renewable energy.**
   Increase the supply of renewable energy and build new renewable energy infrastructure.
   eg. increase the amount of rooftop solar power generation; supply more biofuels for transportation

This approach will move the City towards deriving 100% of its energy from renewable sources. The sections that follow outline how these principles will be reflected in action. The anticipated reductions in carbon pollution that will result the actions outlined in the *Renewable City Strategy* to transform the way we use energy and the systems that supply our buildings and vehicles are shown below.

Renewable City Strategy: A Strategy in Context

Strategic City Plans

The City of Vancouver has a series of plans that are integrated to achieve multiple concurrent benefits, the *Renewable City Strategy* being the latest addition and for which there will be:

Complete Integration

- *Greenest City Action Plan*
- *Transport 2040*
- *Zero-emission New Building Strategy* (under development)
- *Neighbourhood Energy Strategy*
- *Long-term Financial Sustainability Guiding Principles*
- *Healthy City Strategy*
- *Building Retrofit Strategy*
- *Rezoning policy for Sustainable Large Developments*

Partial Integration

- *10-year Capital Strategic Outlook*
- Mid- to long-term Financial and Capital Plans and Budgets
- *Regional Context Statement* (in response to *Metro Vancouver Regional Growth Strategy*)
- *Vancouver Economic Action Strategy*
- *City of Vancouver Digital Strategy*
- *Climate Adaptation Strategy*
- *Waste Management and Resource Recovery Long Range Strategy* (under development)
- Community Plans and Public Benefit Strategies (ongoing)

The *Renewable City Strategy* is the natural continuation of the *Greenest City Action Plan* that establishes the City's environmental targets to 2020. Many of the initiatives in the *Greenest City Action Plan* will have been embedded and mainstreamed within the City and its services by 2020; however the need to make transformational change in our energy system continues and it is prudent to start that planning now. The *Renewable City Strategy* is the response to that prudence, and compliments the City's existing plans that constitute the City's strategic approach to the three pillars of sustainability- social (Healthy City Strategy), economic, (*Vancouver Economic Action Strategy*) and environmental (*Greenest City Action Plan*).

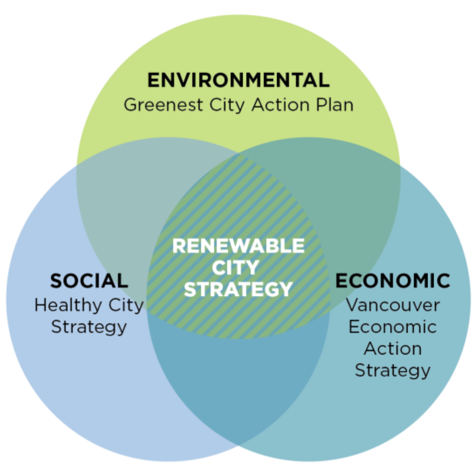


***Figure 2 – Renewable City Strategy* link with sustainability principles**

Regional Planning

The City of Vancouver cannot act in isolation when transitioning to using 100% renewable energy. Metro Vancouver's *Regional Growth Strategy* describes how the region as a whole is to respond to increases in population and jobs, and contains strategies to advance five goals related to urban development in key areas: the regional economy, the environment and climate change, housing and community amenities; and the integration of land use and transportation. Vancouver's *Regional Context Statement* describes our own city's response to growth and development imperatives.

Through Metro Vancouver's *Integrated Air Quality and Greenhouse Gas Management Plan* and *Integrated Solid Waste and Resource Management Plan*, Metro Vancouver has established clear frameworks by which political, policy and service roles can act to support the use of renewable energy sources at the regional level.

Provincial Policy

The Provincial Government of BC has in place a number of plans that support the development of 100% renewable energy resources. The City of Vancouver encourages the current and successive Provincial Governments to continue with these commitments, devote additional resources to this transition and accelerate the pace at which their initiatives are implemented.

- BC Climate Action Plan (successor under development)
- BC Energy Plan
- BC Bioenergy Strategy
- BC Air Action Plan

Federal Policy

The Federal Government's most relevant policies related to renewable energy are currently limited to infrastructure planning and funding. There is need for more explicit federal policies and programs to support renewable energy, energy efficiency improvements, and the pricing of carbon pollution.

Strategy Consultation and Development

The *Renewable City Strategy* has been developed in cooperation with a wide range of stakeholders.

The *Renewable City Action Team* was convened with representation from local environmental and civil society non-profit organizations, academia, regional and provincial government, the business community, and the local utilities. The *Renewable City Action Team* provided strategic oversight of the strategy's development and gave access to the latest thinking on renewable energy and greenhouse gas emission reduction, while ensuring that the strategy addressed the multiple needs of Vancouver's residents. The City of Vancouver would like to thank the *Renewable City Action Team* for their thoughtful comments and guidance in helping develop the *Renewable City Strategy* and look forward to their continued involvement as the *Renewable City Strategy* is implemented.[1] The members of the *Renewable City Action Team* were:

[1] Representation on the *Renewable City Action Team* does not explicitly or implicitly represent endorsement of the *Renewable City Strategy* by the individual or organization presented.

Gregor Robertson *(Co-Chair)*, Mayor, *City of Vancouver*

David Boyd *(Co-Chair)*, Adjunct Professor School of Resource and Environmental Management, *Simon Fraser University*

Alex Lau, Vice President, *Golden Properties Ltd.*

Allan Neilson, General Manager Policy Planning and Environment, *Metro Vancouver*

Brent Gilmour, Executive Director, *Quality Urban Energy Systems of Tomorrow (QUEST)*

Cara Pike, Executive Director, *Climate Access*

David Porte, Chair, *Urban Development Institute*

Ian MacKay, CEO, *Vancouver Economic Commission*

James Tansey, Executive Director Centre of Social Innovation and Impact Investing, *University of British Columbia*

Joanna Sofield, General Manager PowerSmart, *BC Hydro*

Marc Lee, Senior Economist, *Canadian Centre for Policy Alternatives*

Mark Jaccard, Director School of Resource and Environmental Management, *Simon Fraser University*

Merran Smith, Executive Director, *Clean Energy Canada*

Peter Robinson, CEO, *David Suzuki Foundation*

Ross Beaty, Executive Chairman, *Alterra Power Corporation*

Susanna Laaksonen-Craig, Head Climate Action Secretariat, *Government of BC*

Tom Pedersen, Executive Director, *Pacific Institute of Climate Solutions*

TransLink, *Transportation Planning and Policy*

Wal Van Lierop, President and CEO, *Chrysalix Venture Capital*

International thought-leaders and peer organizations also provided feedback on initial drafts of the plan. The City of Vancouver particularly looked to the City of Stockholm's *Roadmap for a Fossil Fuel Free Stockholm 2050* and the City of Copenhagen's *CPH 2025 Climate Plan* as world leading cities with to ambitious but achieve climate and energy plans. These cities also provided a comparable context for Vancouver with similar populations, climate, energy systems and public desire to act. Industry and technology associations also provided input on the technical aspects of moving to the use of 100% renewable energy.

Members of the *Carbon Neutral Cities Alliance*, that comprises the world's 17 leading cities taking action on climate change, provided review and feedback on initial drafts of the strategy, as did some delegates from international organizations who had attended the *Renewable Cities Global Learning Forum in May 2015.* The Forum was a collaboration between the City of Vancouver and the Simon Fraser Centre for Dialogue, that brought together over 300 delegates to discuss the challenges, barriers, and opportunities of becoming a renewable city.

Through the summer of 2015 the City held *The Bright Green Summer*, a series of events and engagements for the public to learn about the *Greenest City 2020 Action Plan* and *Renewable City Strategy*. During the *Bright Green Summer* the City went out to public events such as the Pacific National Exhibition showground, 'Doors Open Vancouver', Pop-up City Hall, downtown Block Party and the Vancouver Public Library summer reading events, to share information on the existing and new *Greenest City* goals, and collect stories and feedback. A renewable energy focused micro-conference brought together 40 sustainability professionals with a range of expertise from green buildings to sustainable transportation who together created a vision of what a renewable city could look like. The City also administered a survey through the City's Talk Vancouver platform reached collected feedback on renewables from over 850 people, 76% of whom supported the direction the City is taking in its climate action work.

Implementation

The *Renewable City Strategy* sets the strategic direction for Vancouver to achieve its 100% renewable energy goals. It is not intended to be a detailed roadmap or technology guide, but instead is a foundation for more detailed planning in the future. Project and technology support that result from the *Renewable City Strategy* will be assessed using techno-economic and socio-economic approaches to ensure that the route followed is technically, economically and socially responsible. The *Renewable City Strategy* proposes a viable route to using 100% renewable energy – it does not purport to be the *only* route to that success.

Following the successful model of implementing the *Greenest City 2020 Action Plan*, departments will be identified that are best suited to implement specific actions and projects. These strategic internal partnerships will deliver outcomes based on already established core relationships while fostering new ones. Continuing to embed the transition to renewable energy within City administration is critical to developing the leadership that will bring long term success. Specific work-plans will be brought forward for Council's consideration as the opportunities arise.

There is a broad need for partnership with the business community, academia, non-profit organisations, surrounding municipalities, other levels of government, public agencies and the public at large to ensure the success of the *Renewable City Strategy*.

The City will ensure that the public is widely engaged and consulted as the strategy moves into implementation. Empowering Vancouver's citizens and communities are empowered to participate in the energy revolution will be a critical success factor. It is important that Vancouver residents and businesses not only understand the changes that will come with a renewable city, but are mobilized to become the agents for and investors in those changes. Vancouver has the capability to be a world-leading knowledge hub for the integration of renewable energy into urban centres. At its heart, a renewable city strategy is not about energy: it is about quality of life, health, affordability, a strong and sustainable economy for generations to come.

The City will develop performance and reporting metrics to support the implementation of the Renewable City Strategy, reporting to Council annually, and revisiting the strategy to ensure that the course it has plotted is still valid and appropriate –this will be updated every four years and major project funding synchronize with the City's capital planning process. The City also commits to share its lessons and learning regionally, nationally and internationally so that others can gain from Vancouver's experience and also make the transition to use 100% renewable energy.

CONTEXT :: Setting the Stage

The Vancouver Stage in 2015

City Profile

In 2013 there were over 605,000 people in the city's 115 *sq. km* area, with the majority of the city street system forming an easily navigable grid. The city is made up of large areas of residential property, many commercial buildings, and a growing number of mixed-use buildings. Vancouver has only three large industrial facilities, a handful of medium-sized industries and a myriad of light-industrial and small-and-medium enterprises.

Metro Vancouver

The City of Vancouver is part of Metro Vancouver, a region made up of 21 municipalities, one treaty First Nation and one electoral area, which together have an area of nearly 2,900 *sq. km* and in 2013 a population of 2.5million.

Population and Job Increases

In the past 25 years Vancouver's population has grown by 34%, with jobs increasing by 30% and energy use by about 15%. Over the same time Vancouver's carbon emissions have dropped by 7%, and are expected to keep falling; showing that the city can continue to grow and be economically strong while removing the burden of polluting carbon emissions. Over the next 35 years the city's population is expected to grow by about 30% (170,000 people), creating 32% more jobs.

Business Profile

Vancouver's business profile is comprised mainly of small-and-medium enterprises, with a growing digital sector and little heavy industry. Over 90% of Vancouver businesses have fewer than 50 employees, and over 70% have 10 employees or fewer. This gives the economy strength through diversity, but so many individual stakeholders makes engaging the business community challenging.

Port Metro Vancouver

Port Metro Vancouver is Canada's largest port, shipping goods valued at over $500 million a day. Port Metro Vancouver acts as Canada's primary gateway to Asia-Pacific economies, and anticipates an increase in container volumes by 70% by 2030 for the two terminals it operates in Vancouver, with significant growth also expected in bulk shipping of agricultural products like grain.

Vancouver's Brand

Vancouver's brand, valued at US$31bn in 2015 when measured by investment, reputation and performance shows that sustainability and existing in harmony with nature are integral to Vancouver's success. Vancouver is recognized globally for its reputation in sustainability, green technology, and environmental protection. This brand value encourages businesses to move and invest here, attracts talented workers, encourages outstanding students and researches to study here and underpins our long-term economic stability.

Housing Cost

The cost of housing in Vancouver is high. To ensure that residents stay here, that the city attracts the best possible people to work here, and to maintain diversity, it is important to ensure housing is affordable for all parts of the community. A move to more efficient, renewably powered homes and better transit provides the opportunity to better meet these needs.

Decreasing Energy Demand

Through energy efficiency and conservation measures, the city's energy use has been decreasing by about 0.8% a year. To ensure the city's energy use is sustainable there is a need to accelerate this reduction so that energy demand reaches a level that can be supplied by renewable sources.

Transportation Fuel Supply and Prices

Much of Vancouver's transportation fuel comes from within Canada, but its price is still affected by world trends. Gas and diesel prices have risen steadily over the past decade and in the medium-to long term are expected to continue in the same direction. There is ongoing volatility of these prices, making it difficult to predict how much fuel bills will be in the future.

Low Cost Natural Gas

Just a decade ago natural gas prices were double what they are today and were rising. Limited supplies meant that natural gas could command a price premium. The discovery in North America of large quantities of shale gas has now caused the price to crash and this low cost is expected to remain for years to come. What's not included in this price are the health and environmental damages caused by climate change that results, in part, from burning large amounts of natural gas.

British Columbia's Carbon Tax

The Province of BC has in place a carbon tax equivalent to 30*\$/t*CO_2*e* levied on about 70% of BC fossil fuel emission sources including the most common fuels like gasoline, diesel, propane and natural gas. The tax, launched in 2008 at 5*\$/t*CO_2*e* and increased by \$5 per year until 2012, is revenue neutral having been balanced by reductions in personal income and corporation tax rates. Provisions are made to reduce the tax collected from low income families and those in northern BC that have greater heating needs.

Renewable Electricity

Vancouver is fortunate to have electrical power which comes mostly from large hydro-electric dams, with small amounts of small-hydro generation, wind, biomass and natural gas. As the sole electrical utility supplying Vancouver, BC Hydro is mandated to produce as much power as BC needs from facilities within the province – it cannot plan to import power to meet demand in BC – and it is regulated to do so with 93% of the total generating capacity met by clean sources.

Infrastructure

Vancouver's infrastructure is in good condition compared to many cities worldwide. This infrastructure allows the city to operate smoothly and effectively, however maintaining our infrastructure is critical. In some cases, no reasonable amount of investment can keep pace with demand. The road space in Vancouver, for example, is at its maximum – no amount of investment can change that, and we must learn how to use our road space differently when creating a vibrant urban landscape.

Transit (Public Transport)

Vancouver's transit system is one of the busiest in North America, and is one where demand exceeds capacity. Finding sustainable funding sources to maintain and expand capacity and reliability in public transportation and rapid transit is integral to reducing vehicle use and achieving our 100% renewable energy goals.

The World Stage in 2015

The Consequences of Continuing to Use Fossil Fuels

Climate change is having impacts across the world; 2014 was the hottest year on record and 2015 is on track to break that record. The burning of fossil fuels, amongst other things, worsens air quality, has direct impacts on human health, and accelerates the loss of natural habitats and impacts agricultural production. The release of carbon dioxide into the atmosphere from burning fossil fuels is affecting Vancouver and its surroundings through sea level rise, more frequent and more severe heat waves, increased frequency and severity of storms, increased winter rainfall, summer droughts and less snow. These changes will continue to worsen in the foreseeable future. There is a need to not only take action to prevent this (climate mitigation), but also prepare for it (climate adaptation).

Population and Urban Growth

The world's population, including Canada's, continues to increase with most of that growth occurring in urban environments. Cities are the engines of the global economy and are responsible for about 70% of the world's greenhouse gas emissions. The benefits that fossil fuels have brought to humanity over the past 100 years or more can no longer be relied upon to continue into the future – in fact, to continue to improve the standard of living for everyone in Vancouver we must transform our city so that it derives all its energy from renewable sources.

Call to Action

There is consensus among world leaders, scientists, and businesses that climate change must be addressed quickly and aggressively if we're to avoid devastating social and economic upheaval world-wide. In April 2015 more than 40 CEO's from some of the world's largest companies, representing 20 economic sectors, with operations in more than 150 countries have called for bold action on climate, while committing to reduce their own corporate emissions. In May 2015 Pope Francis released his encyclical that warned there would be serious consequences for all of humanity if we fail to take action on climate change. These calls to action make clear that climate change is not a problem that can be left to future generations. The world conversation on climate change is one wholly focused on action and the Renewable City Strategy is an affirmation of Vancouver's commitment to continue to take action now and into the future.

United Nations Climate Conference 2015

The United Nation Framework Convention on Climate Change (UNFCCC) will hold its 21st Conference of the Parties (COP21) in Paris in December 2015. The objective of COP21 is to establish a legally binding and universal agreement on climate action, with intent to limit world greenhouse gas emissions to hold the increase in global average temperature below two degrees – the generally accepted limit if irreparable ecosystem damage is to be avoided. Together, the 149 countries that have submitted commitments to the UNFCCC produce over 90% of current global emissions, compared to the 14% of global emissions produced by the 35 countries that signed the Kyoto Agreement in 1997, the first and now expired global climate agreement. The stage is set for a significant shift in the way the world is tackling climate change.

Action from the World's Big Emitters

The world's two biggest economies, China and the United States, were in 2010 responsible for over 38% of global greenhouse gas emissions. In November 2014 China and the U.S. signed a joint announcement in climate change and clean energy cooperation that committed the U.S. to cut its emissions by 26 to 28% below 2005 levels by 2025 mandated and for China's greenhouse gas emissions to peak in 2030. With the world's largest economies supporting climate action and clean energy, the stage is set for step changes in how the world derives its energy.

Municipal Leadership on Climate Action

Urban areas are home to the majority of the world's population and are on the front line of climate change impacts. As a result cities and their mayors are leading in responding to and averting the worst effects of climate change. Some cities are acting in the absence of national leadership and are primed to make even more progress with better harmonized national policy. In 2014 the United Nations launched the Compact of Mayors a global initiative for cities to commit to action on climate change and report their progress. Currently the Compact of Mayors has 197 members, including Vancouver, from 53 countries.

The Social Cost and Regulation of Carbon

The emission of carbon pollution has social costs that are not reflected in its direct price. These "externalities", as they are called by economists, include human health impacts, sea level rise, lost agricultural productivity and habitat loss. To illuminate and mitigate the full impacts of burning fossil fuels, it is important to price their 'externalities'. That price may take the form of a tax on those who emit the carbon, like we have in BC, or it may take the form of a 'cap and trade' system in which carbon emissions become a commodity like any other that can be traded, like existing programs in Ontario, Quebec, California and Europe.

Properly pricing carbon supports better decisions when investing in energy systems, whether a county building a power plant or an individual is buying a car. According to the World Bank there are about 40 nations and 20 sub-national jurisdictions that have in place a price on carbon (either as a direct tax or through a trading system) covering about 12% of global greenhouse gas emissions. Beyond direct pricing of carbon pollution, regulations that discourage fossil fuels are already in place in China, South Korea, Japan, the United States and India to name just a few of Canada's trading partners. The move away from fossil fuels is underway and only expected to accelerate - Sweden has recently become the first country to commit to become fossil fuel free.

Underway Now: **The City of Vancouver is advocating for an integrated regional, national and international price on carbon**

The is a need to account for the economic impacts of carbon emissions and support a transition away from the use of fossil fuels as our primary energy source. The most effective way to do this is to put on price the emission of carbon pollution. Given that the environmental and social impacts of carbon pollution are felt globally the price applied to emissions must also be global. This is most likely to be made a reality through the setting of regional and national carbon pricing mechanisms that can then be internationally harmonized. The need for governments to establish an incrementally increasing carbon tax is paramount.

Fossil Fuel Divestment and Renewable Energy Investment

The movement by pension funds, private equity, academia and some governments to withdraw investments in companies that extract fossil fuels is one of the fastest divestment movement in history, if not the fastest. Some are removing finance from fossil fuel extraction companies on moral grounds, while for others it is simply seen as the prudent long-term investment decision. Investment in renewable energy projects (excluding large hydro) jumped by nearly 17% in 2014 compared to 2013; 2014 also seeing an all-time high in the capacity of wind and solar power installations, 20% higher than in 2013.

Change Is Inevitable

The world is moving away from fossil fuels and Vancouver can either postpone action and play catch-up at a later date, or continue to take advantage of emergent social and economic opportunities. The transition is not about abstinence or making sacrifices; it is about growing a city that better meets our needs. The transition to renewable energy, although likely to be quicker, is not so different from moving to kerosene from whale oil or the revolution that happened when horse and buggy became the motor car. In both cases the inevitable change brought improvements and opened more doors. The early improvements in quality of life these new sources of energy provided are now commonplace, and as our increased dependence on fossil fuel for building energy use and transportation has become damaging to our ecosystems and healthy we have outgrown their relative utility. A renewable future will afford society the next set of opportunities across a broad spectrum of our lives and our children will look back and ask, “What took you so long?”

The Transition to Renewable Energy

A Strengthening Economy

The transition towards the use of only renewable energy provides business opportunity through catalysing the development of new renewable energy and energy efficiency technologies and galvanizing the emergence of new business models to capitalize on the change. Preparing Vancouver for the economy of the future, one which is diversified, not tied to fossil fuels, adaptable, and resilient, is foundational to successfully eliminating our dependence on fossil fuels.

A robust and thriving renewable economy will attract and retain human capital, promoting higher and more inclusive employment. Being at the vanguard of the renewable energy revolution will create wealth through innovation and the development of intellectual property and will attract new investment from all aspects of the business and social society.

Affordability

The move to derive 100% of Vancouver's energy from renewable resources will ensure that the city remains economically strong and culturally vibrant. There will be changes in some aspects of the city, but these changes are aimed at employing technologies, like rooftop solar panels and electric vehicles, that have lower operating costs than fossil fuel equivalents and for which the up-front costs are rapidly coming down. Buildings that use less and conserve more energy reduce the energy bills for renters and owners alike. A move towards electrification and the use of renewables to produce that electricity, with BC's regulated utilities, provides more certainty in long-term energy costs when compared to the variability in fossil fuel prices, and technologies like solar panels even allow residents or communities to produce their own electricity. Communities that prioritize active transportation and that are well served by transit can save money by reducing the need to buy fuel for their cars, and can increase job opportunities.

The consequences of inaction, such as poor air quality and detrimental health impacts, can be avoided through the adoption of renewable energy. The world is moving towards controlling and limiting carbon pollution – the move away from fossil fuels has started, and as a city it is prudent to prepare for that. Over the past decade, hundreds of requirements for carbon reduction, energy efficiency, and renewable energy have been brought in around the world, and this trend is not only expected to continue but to accelerate. The *Renewable City Strategy* embraces these changes and is preparing the city to best meet the needs of its citizens now and into the future. The transition to the use of only renewable energy will need to manage up-front costs with lower operating costs, and through the *Healthy City Strategy* and Mayor's Task Force on Affordable Housing, the City of Vancouver will continue to work with residents, community associations, social enterprises, and other levels of government to support its residents in the transition.

In many cases, carefully designed policies and actions can support the use of renewable energy without customers even realizing it. The Southeast False Creek Neighbourhood Energy Utility, having displaced natural gas use, provides low-carbon heating at rates currently comparable to BC Hydro and with a long-run trend to be cheaper. The Provincial renewable and low-carbon fuel requirement regulation currently saves nearly one million tonnes of greenhouse gas emissions a year with few consumers realizing, and the Provincial carbon tax has cut emissions without harming economic activity.

Financing the Transition

The rationale to act now to both mitigate and adapt to climate change is twofold. First, acting now has a larger and longer lasting positive impact than delaying; the less is done to mitigate climate change the worse the impacts will be and the more it will cost to adapt in future. Secondly, some investment decisions made today will last for 100 years or more, it is imperative to ensure market choices and consumer choices are made not for short term gains, but in the interest of long-term security.

Traditional financing mechanisms can be applied to non-traditional technologies, as has been the case for electric vehicle development. New technologies also often benefit from feed-in tariffs that secure a set price for the energy they produce—this mechanism has been used to great effect in many places to increase the amount of wind and solar power generation at both the utility and community scales. There are also emergent financing mechanisms such as green bonds that support green infrastructure projects. Carbon tax revenues and other environmental levies can raise revenues for green funds that can be used for climate action as direct investment, tax relief, low-interest loans, and other supporting mechanisms.

The Path to Renewable Energy

The transition to the use of 100% renewable energy will not simply be a steadily increasing portion of renewable energy use. Currently Vancouver's energy system is dominated by grid-supplied electricity, natural gas, gasoline, and diesel. Each of these and their respective uses will undergo technological, market, and regulatory changes at different times and at different rates, as will the technologies that replace them. The changes in the energy system are likely to be typified by rapid step changes, although renewable energy projects are now starting to provide superior long-term price guarantees compared to fossil fuels. With such an array of factors influencing how the energy system is going to change, it is not possible to make long-term financial predictions of the costs and revenues, although it is clear that a reduced dependency on fossil fuels and the adoption of renewable energy has a broad array of benefits, both financial and societal. The City will continue to use proven approaches such as strategic partnerships, financing from senior levels of government, and its own finances to support the transition.

Renewable Energy Cost Reduction

If humanity is to avoid catastrophic climate impacts we cannot extract all the fossil fuels we already know about; and as those reserves become progressively more expensive to extract, renewable energy technologies become ever more cost competitive. The cost of renewable energy technologies has dropped consistently over the past decades, and solar has seen a particularly rapid cost reduction decline and associated burgeoning of world-wide installation. The regulated nature of BC's electrical utilities provides price certainty and limits costs increases for electrical customers when compared to fossil fuels. Current fossil fuel prices may be low compared to a few years ago, but have a long-term upward trend. According to the US Energy Information Administration the inflation adjusted cost of fossil fuels approximately doubled between the mid-1970s and 2011. Over the same time period, the cost of solar photovoltaic panels dropped approximately hundred-fold, the cost of wind approximately thirty-fold; and the cost of geothermal and biomass by about 50%. Fossil fuels prices, like all commodities, respond to a variety of unpredictable factors affecting their supply with prices often changing daily; although renewable energy technologies are also subject to many factors their price is much more predictable, currently acting more like that of digital technologies and less influence by their inputs (wind and sunshine). The diminishing cost and cost certainty of renewable technologies coupled with the increasing price of fossil fuels and their price volatility make a strong case for more stable investment and cost management with renewable energy sources.

Technological Revolution

The technological and digital revolution that has come in the past decade is showing no sign of slowing down. The "internet of things", the explosion of mobile technology, the role of disruptive technologies like autonomous vehicles and home electricity storage as well as changes in our own behaviour will define what the transition to 100% renewable energy looks like. Such disruptive changes, their scale, interplay and timings cannot be predicted beyond knowing that they will come and the *Renewable City Strategy* must be adaptive enough to not only respond, but maximize the opportunities they bring.

The City's Role

Direct Control: City Regulatory Powers

The City of Vancouver has control over municipal infrastructure (active transport infrastructure, roads, parking, sewers, water distribution, etc.) and regulatory powers established by the Vancouver Charter. Under the Vancouver Charter the City can guide development and urban design through land use and zoning /rezoning policies and guidelines. The City also has the direct power to regulate building standards and ensure building safety. The City has the necessary authorities to establish neighbourhood renewable energy utilities, as has been done in Southeast False Creek, River District and Northeast False Creek. However, at the moment in Vancouver there is only one electrical and one natural gas utility to serve the city; both are regulated by the BC Utilities Commission, which is under Provincial oversight.

Partial Control: Transportation

While the City of Vancouver has little to no direct jurisdictional control over vehicles, it has a strong influence over travel behaviour through land use and transportation planning, including signal operation, how streets are designed and space allocated, and where services and amenities are located. Public transportation infrastructure, including bridges and the Major Roads Network, is the shared responsibility of the City and TransLink, the local transit authority that also delivers the regional transit system.

TransLink's Board of Directors is appointed with Provincial oversight by the Mayors' Council, itself an advisory body made up of mayors and representatives from cities throughout the Metro Vancouver region, of which Vancouver is one. The Province of BC is also represented on the TransLink board and influences TransLink strategic planning heavily. TransLink is required to provide a regional transportation system that supports Metro Vancouver's *Regional Growth Strategy*, air quality and greenhouse gas reduction objectives, and the economic development of the region.

Vehicle fuel efficiency and pollution standards for new vehicles are set by the Federal Government. Until 2014, the regional AirCare program ensured that vehicles, once purchased, met air pollution standards. Metro Vancouver is working with the Provincial Government and other partners to explore new programs for managing emissions from light and heavy-duty vehicles.

Partial Control: Waste

The City of Vancouver has a degree of jurisdictional control over the local waste management system. Vancouver is also part of a regional waste system managed by Metro Vancouver, under Provincial oversight, that combines private and public haulage and disposal. Residential waste collection and disposal in Vancouver is managed in part by the City through its own collections and the Vancouver Landfill in Delta. Private haulers play an important role in waste collection and disposal, and primarily serve the industrial, commercial, institutional and multi-family residential sectors.

Limited Direct Control: Lands Under Provincial and Federal Control

Large transportation infrastructure like rail lines and the container and shipping facilities at Port Metro Vancouver are under federal jurisdiction and thus the City's regulatory authority and ability to influence renewable energy behavior is quite limited. Similarly, there are some First Nations Reserves within the City's boundaries, and while the City has some regulatory authority over such lands, these areas are primarily under federal jurisdiction and so again the City's regulatory authority is quite limited within the sphere of renewable energy matters. Finally, provincial legislation exempts provincially-owned land from certain types of Vancouver's land use and development laws and so further limiting the City's regulatory authority over this type of land. Nonetheless, with respect to all lands subject to Provincial or Federal jurisdiction, the City will advocate for action to support the use of renewable energy.

No Direct Control: Fostering Change through Influence and Advocacy

The City will always work to establish an environment that fosters inclusiveness and innovation; using its powers of advocacy and influence, as well as working in strategic partnerships the City will act to expand the use of renewable energy, even in areas where it has no direct jurisdiction.

Vancouver has a long history of supporting climate action, from the *Clouds of Change* reports in 1990, to the *Community Climate Change Action Plan* in 2005 and the *Greenest City 2020 Action Plan* in 2011, and now the *Renewable City Strategy*. These plans and the progress they have delivered have been built upon strong and broad public, business and political support, as well as partnerships with local utilities, the development community, academic institutions and NGOs.

The City of Vancouver has ensured that there is strong organizational capacity across all its city-wide functions. To achieve a 100% renewably powered future, this capacity will have to be expanded, not only for the City's own operations but to lead and guide the public and business communities. There is also the need to ensure that renewable, clean, green, and emergent technologies are readily available and that people have the skills to implement them. The City can educate and empower people and businesses to change and directly engage in energy production and conservation, while itself leading both locally and internationally.

Based on current regulatory powers and which organizations hold those powers the City of Vancouver has regulatory authority over about 40% of fossil fuel energy reductions and renewable energy increases; this is predominantly due to the City's ability to regulate building standards. The Province of BC through its ability to regulate utilities and the transit system as well as control vehicle fuel standards has authority over about 40% of the changes that need to take place; the Federal Government, primarily through its regulation of vehicle efficiency standards, is responsible for about 20% of the required changes. It must however be noted that the City has limited authority over existing utilities and any changes to those systems would significantly impact Vancouver's ability to achieve the 100% renewable energy target.

Figure 3 **– City of Vancouver's Jurisdictional Role**

City Services as a Catalyst for Renewable Energy

The City of Vancouver can catalyze change by being a leader in the use of renewable energy in its own operations, and already has 46 hybrids and 29 electric vehicles in its fleet of 180 light-duty vehicles. The City has fitted 107 idle-stop devices to its fleet vehicles to limit emissions from idling, and since 2008 has cut fleet emissions by 10% and overall corporate emissions by 25%.

The City also provides a range of services to its citizens, and the pursuit of 100% renewable energy will be integrated into those services. Vancouver's services are funded through property taxes (56%), utility fees (20%), and user fees (24%) such as parking meter revenues and business licenses.

Licensing Powers Quick Start: **The City of Vancouver will investigate how best to use its licensing and permitting powers to accelerate the adoption of renewable energy**

The City will investigate and make recommendations on how its business licensing and permitting authority can be used to support the market adoption of renewable energy for activities undertaken within the city.

Given the limited funding sources available to municipalities throughout Canada, taking into consideration businesses and residents' ability to pay taxes and fees, the City will work in partnership with senior levels of government, charitable foundations and private financiers to enable the private sector to develop viable and cost-effective renewable energy technologies.

The mid- to long-term implications of transitioning Vancouver to 100% renewable energy will be determined as part of the City's strategic service, capital and financial planning, taking into consideration long-term financial, environmental and social sustainability. The approach will consider the following:

- Where the City has regulatory authority to enable and/or require the transition to 100% renewable energy (typically in building codes, land use, licensing and permitting and bylaw enforcement), the City, in consultation with key stakeholders, will develop strategies that set clear and attainable goals, timelines, and implementation plans;
- Where other levels of government have regulatory authorities to enable and/or require the transition to 100% renewable energy, the City will focus on education and advocacy to support the case for such regulation;
- Where businesses, consumers, academia or other entities are the key agents for change, the City will focus on strategic partnership, education and advocacy; and
- Where its municipal operations are involved, the City will develop implementation and funding strategies that balance financial, environmental and social considerations.

Purchasing Power Quick Start: **The City of Vancouver will investigate how best to use its purchasing power to accelerate the adoption of renewable energy**

The City will investigate and make recommendations on how to use its purchasing power to support the adoption of renewable energy.

City Service Delivery Renewable Energy Priorities

S.1 The City will adopt a comprehensive approach to the consideration of climate change as part of its service planning

The City commits to develop a strategy to support the transition to 100% renewable energy as part of its strategic service, capital and financial planning. Ensuring that service plans and associated funding strategy supports the transition to renewable energy is critical to meeting the City's renewable energy and greenhouse gas goals. Since infrastructure decisions made today will have impacts that last for 50, 80 or even 100 years, it is important that the City plan accordingly.

S.2 The City will adopt a comprehensive approach to pricing carbon emissions for municipal operations

To support adoption of renewable energy technologies for its municipal operations, the City will develop a robust approach to pricing carbon pollution and incorporate it into decision making processes.

S.3 The City will develop a framework to assess how City enabling tools may be used to support the transition to 100% renewable energy

To facilitate and/or expedite the transition to 100% renewable energy, strategic enabling tools may be considered. The role of incentives to support technologies in their early deployment can be effective in helping new technologies establish a market share. The development of an evaluation framework with clear guiding principles and value for money parameters will assist the City in identifying and evaluating potential enabling tools.

S.4 The City commits to keep abreast of financing mechanisms available that enable the delivery of renewable energy technology and other green infrastructure

Financing mechanisms such as green bonds, carbon taxes and green funds have emerged in recent years to finance green infrastructure projects; these and other mechanisms are rapidly changing how infrastructure, services and technology can be financed. The City will consider all appropriate funding mechanisms when formulating its long-term capital funding/financing strategy.

The Economic Opportunity of Renewable Energy

Imagine a city where jobs and businesses are diverse and economically strong, where businesses both big and small invest in the city, and where businesses thrive using only renewable energy.

Vancouver's Economy Now and to Come

The *Renewable City Strategy* provides a significant economic opportunity for Vancouver, and supports the delivery of the *Vancouver Economic Action Strategy*. Within the next fifteen years, global investment in clean energy is expected to constitute almost three quarters of total global energy investment; in fact, Canada already has more jobs in clean energy than in oil and gas. This global move away fossil fuels is driven by a desire from businesses, governments, and citizens alike to secure stable and reliable energy at a predictable cost. Renewable energy generation and storage technologies like wind, solar, and home battery storage are rapidly dropping in price at both the industrial and local scales. This is creating new business models, where individuals and neighbourhoods are no longer passive consumers, but active "pro-sumers" producing, using, and selling their products and services.

Around the world, cities are capitalizing on these trends, with Vancouver and the Vancouver Economic Commission at the fore. Even in the face of world economic challenges Vancouver has, over the past five years, enjoyed steady economic growth. Cleantech is the fastest-growing business sector in Canada, and Vancouver is home to more than 25% of those firms; the Vancouver region alone is responsible for more than 75% of the world's hydrogen fuel cell research and development.

Vancouver has always been a place of innovation, home to world-changing ideas and businesses. Business has proven to be a powerful driver for change. Businesses in Vancouver are delivering solutions to sustainability challenges, testing alternatives to traditional ways of operating, and sharing these innovations around the world. Demand has skyrocketed for goods and services that align with the values of health, well-being, environmental sustainability, and social equity. That demand is coming from both international and local markets.

Underway Now: **Expand and accelerate the *Green and Digital Demonstration Program***

The Vancouver Economic Commission's Green and Digital Demonstration Program*, which leverages City assets and infrastructure to pilot, demonstrate, and accelerate the commercialization of cleantech and digital innovations, has raised the profile of emerging businesses and fast-tracked their growth. As this program develops further, the Vancouver Economic Commission will emphasize clean energy pilots and demonstrations, to ensure that Vancouver entrepreneurs know the business environment is ready for clean energy technologies and the digital technologies that support them.*

The extent to which Vancouver remains competitive and resilient, and generates opportunity for our future citizens will be defined by our efforts to mitigate and adapt to climate change, as well as our efforts to future-proof our economy. As a city we must continue building a resilient economy, one that can withstand the boom and bust cycles that are amplified when economies hang their success on a small handful of industries. Investment now in a renewably powered economy is an investment with lasting returns. Further developing Vancouver's renewable energy advantage is not only necessary for creating a healthy and sustainable city, but also an incredible opportunity to generate wealth, build resiliency in the face of volatile energy prices and climate change risks, and improve social equity.

Business Emissions Quick Start: **Use the Vancouver *Business Energy and Emissions Profile* to develop a targeted business energy use reduction and fuel switching strategy**

The Vancouver Business Energy and Emissions Profile *provides data on energy cost drivers for different business types within the city, and provides a window into where strategies to take action could be most effective in both cost and energy use reduction.*

Economic Opportunity Priorities

E.1 Support innovators through business and technology research, incubation, acceleration, and demonstration.

The Vancouver Economic Commission in partnership with the City will develop support mechanisms for renewable energy and energy efficiency research, development and commercialization. It is important to create the conditions for businesses to thrive and be successful. Renewable energy companies are a subset of Vancouver's thriving green economy sectors and will need support in the areas of innovation, financing, talent, and scaling up for global distribution. Technology research and development activities can often be supported through grants and academic partnerships; however, commercialization presents challenges for entrepreneurs that need not only business strategy and marketing support but office and industrial space and the launching of cleantech and clean energy accelerator programs will help remove those barriers.

E.2 Actively work with businesses to increase the use of renewable energy

The Vancouver Economic Commission and the City of Vancouver are already working with businesses, regional government, community organizations, and academic institutions to make the False Creek Flats the greenest place to work in the world. Redeveloping this central industrial and employment area will lead it to be a showcase of sustainability and innovative business models and a home to green buildings; build on resilient and smart infrastructure; become a hub for green economy industries; and support emerging "circular economy" initiatives. This area affords the city the opportunity to attract new, impact-based investment will drive business transformation within the city. New infrastructure will likely be required to support green enterprise and may include centralized alternative fueling infrastructure for publicly and privately operated return-to-base fleets or new community-scale energy facilities.

The Vancouver Economic Commission will continue to provide leadership and engage with businesses to deliver the actions of the green economic strategy, particularly through online engagement and education through which there will be an emphasis on business case for renewable energy opportunities. Vancouver businesses have shown leadership, yet despite technological advances and cost reductions in renewable technologies the business community and the City will need to work together to overcome barriers and find technical and financial pathways to support businesses with adoption of new technologies and become more energy efficient..

E.3 Target key events and organizations that represent cleantech and renewable energy to strengthen Vancouver's economy

The City will continue to leverage key events and partner with strategic and government organizations to emphasise renewable energy investment. Vancouver's clean energy ecosystem brings together major firms, start-ups, developers, financiers, and NGOs to share best practices and foster collaboration. Ensuring that Vancouver has access to both human and financial capital is imperative to maintaining the strength of the city's strategic partners and send a strong market signal that will contribute to the city's continued success.

Vancouver's green brand is exceptionally strong and attracts companies and talent with similar core values. Through events such as GLOBE and TED, Vancouver has already established itself as the world stage for environmentally responsible business. Broadening this further to support the City's renewable energy goals can drive even stronger green economic activity.

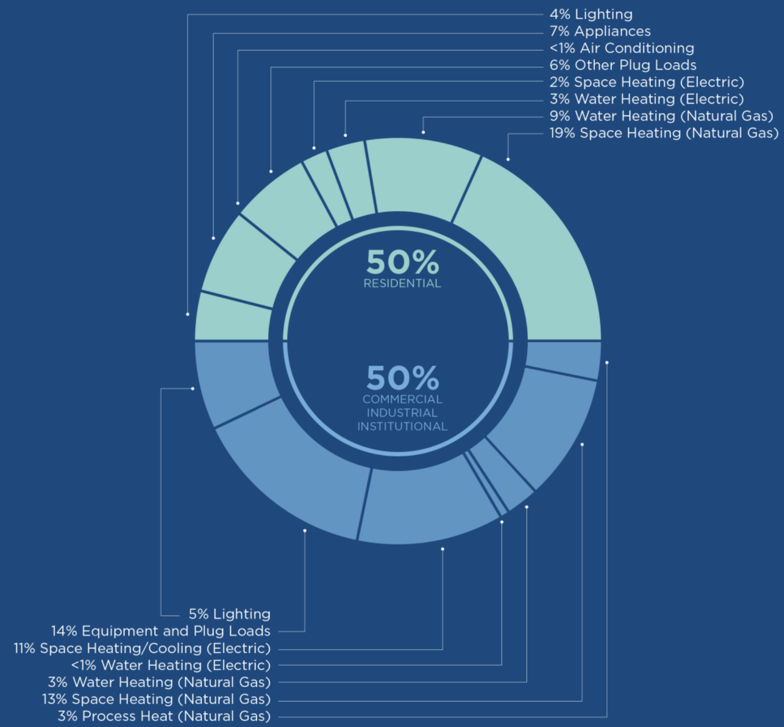
E.4 Attract "green capital" and enable more innovative financing mechanisms for clean and renewable businesses

Vancouver has an existing capital attraction initiative, which will be extended and expanded to specifically target investors in renewable energy from global angel investor communities and venture capitalists, to private equity and pension funds. Vancouver is world renowned for its engineering talent and culture of entrepreneurial spirit, but lacks access to investment capital. This capital is needed to build materials management facilities, establish manufacturing facilities, or convert fleets or infrastructure to more sustainable systems.

Expanding the Vancouver Economic Commission's existing work to focus on angel investors, venture capital, private equity, and large institutional funds as well as crowdfunding and citizen driven finance, can help attract renewable energy expertise, capital and companies. It is important to send a strong market signal to investors that Vancouver is the place where ideas come to reality and is *the* place to invest.

Summary :: Achieving Renewable Building Energy Use in Vancouver

Imagine a city where homes and offices have clean and comfortable environments, are less expensive to heat and cool, and use only renewable sources of energy.



BUILDINGS

Zero-Emission Building Priorities

Based on the end uses presented in the pie-chart above the City of Vancouver has established the following building priorities:

B.1 New buildings to be zero-emission by 2030

- B.1.1 Adopt and demonstrate zero-emission standards in new City of Vancouver building construction
- B.1.2 Ensure rezoning policy leads the transition to zero-emission buildings
- B.1.3 Incentivize and streamline the development of exemplary buildings
- B.1.4 Establish and enforce specific greenhouse gas intensity limits for new developments
- B.1.5 Develop innovative financing tools to help fund new zero-emission buildings
- B.1.6 Establish partnerships to build industry capacity
- B.1.7 Mandate building energy benchmarking and labelling requirements

B.2 Retrofit existing buildings to perform like new construction

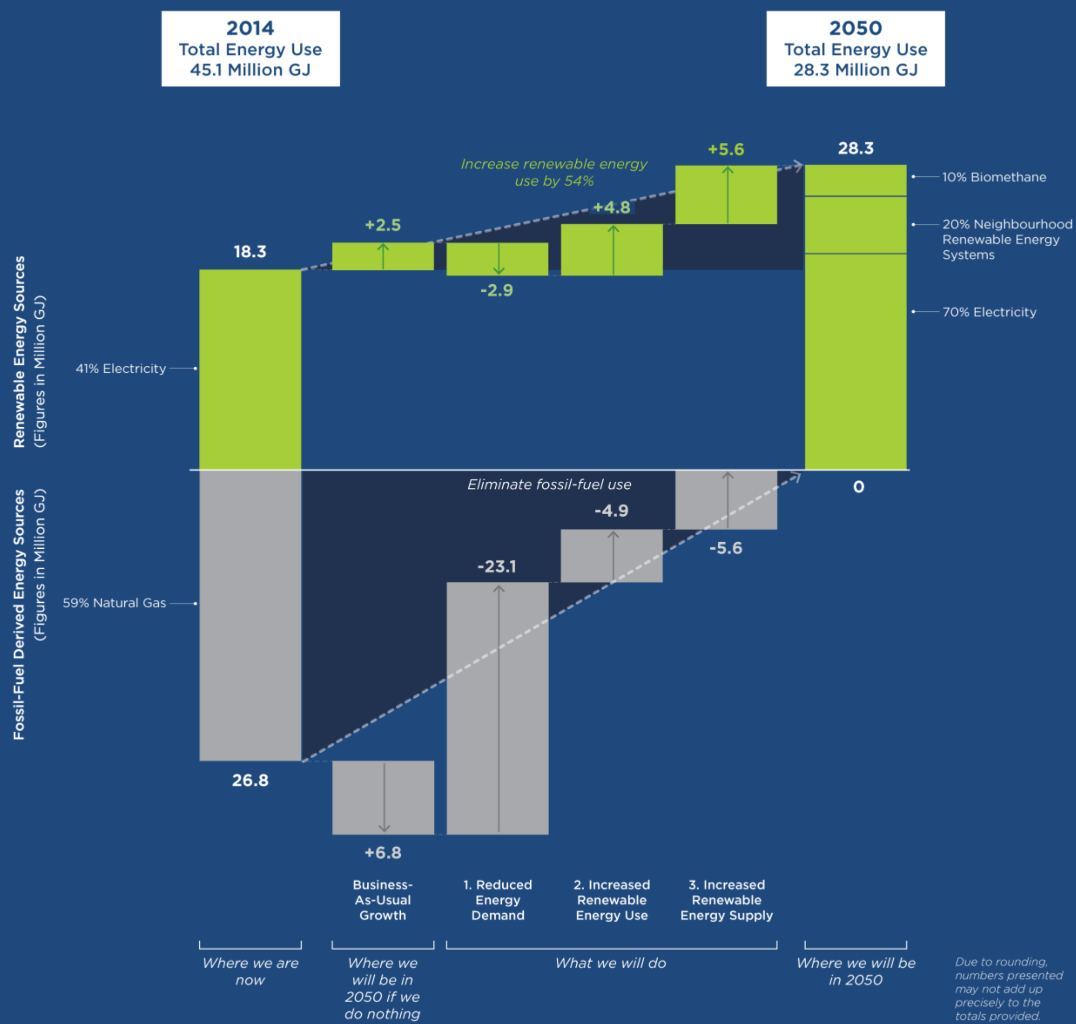
- B.2.1 Use the Zero-emission New Building Strategy to reduce the need for building retrofits
- B.2.2 Mandate energy efficiency improvements for existing buildings
- B.2.3 Provide flexibility to achieve energy efficiency requirements through the support of on-site generation or neighbourhood energy system connection
- B.2.4 Facilitate modest retrofits through structured guidance and the provision of incentives
- B.2.5 Increase renewable energy use by large energy consumers

B.3 Expand existing and develop new Neighbourhood Renewable Energy Systems

- B.3.1 Expand existing Neighbourhood Renewable Energy Systems
- B.3.2 Enable the conversion of the downtown and hospital steam systems from natural gas to renewable energy
- B.3.3 Enable the development of new neighbourhood renewable energy systems for downtown and the Cambie corridor
- B.3.4 Continue to enforce, and update as required, building and renewable energy supply policies that support neighbourhood renewable energy systems

B.4 Ensure grid supplied electricity is 100% renewable

- B.4.1 Partner with utilities to increase the supply of renewable energy
- B.4.2 Partner with utilities to implement a smart grid that meets Vancouver’s energy needs



A Vision for Vancouver's Buildings in 2050

By 2050, about 40% of Vancouver's buildings will have been replaced and built to the carbon-neutral standards set out in the *Greenest City 2020 Action Plan* or to zero-emission standards which will have come into effect before 2030. Of the buildings which remain there will be an even split between those built to current standards and those built to standards pre-dating 2010. The vast majority of buildings that have not been built to zero-emission standards will have undergone deep retrofits to bring their energy performance up to the standards expected of new construction, or have been connected to the one of Vancouver's renewable neighbourhood energy systems. These changes will cut city-wide building energy use by over a third compared to 2014.

Current business-as-usual energy use with existing City and Provincial policies would likely mean an increase in city-wide electricity use by 2050 of approximately 10% over 2014, with large amounts of fossil-fuel-derived energy remaining. The *Renewable City Strategy* would lead to an increase in electricity use of about 20% by 2050 over 2014 levels, but would in the process eliminate Vancouver's need for fossil fuels.

Building performance improvements and the expansion of neighbourhood renewable energy systems that can provide heating and cooling will limit increases in electrical demand. There will be only minimal need for large electrical generation and transmission infrastructure investments – British Columbia's electrical grid can be capitalized upon and optimized to meet demand with only modest generation additions. The use of on-site power generation from solar or the meeting of heating needs through air-source heat pumps or geoexchange systems will further limit the need for new electrical generation. For those buildings that cannot be brought to perform to zero-emission standards and that cannot be connected to renewable neighbourhood energy systems, biomethane will be used to meet heating needs, although this need is expected to be minimal and biomethane will play a more significant role in the transportation system as an energy-rich mobile fuel.

The incremental electrical demand increase over business-as-usual will in part be due to the electrification of personal transportation. Since typical daily commutes are short in Vancouver, and the need for personal vehicle use will decline substantially by 2050, vehicle electrical demand will constitute only about 5% of total annual city-wide electrical demand, with this deamdn required to be met through home and work-place charging infrastructure. New smart-grid technologies will manage electrical distribution, on-site generation, and electric vehicle charging.

BUILDINGS :: Making Building Energy Use Renewable

Imagine a city where homes and offices have clean and comfortable environments, are less expensive to heat and cool, and use only renewable sources of energy.

Building Energy Demand

When taken together, residential, commercial and industrial/institutional buildings form the largest single source of emissions in Vancouver, constituting 56% of the city's total in 2014. The City of Vancouver is tackling building energy use according to where it can have the largest carbon reduction impact, primarily space heating and hot water.

Consistent with the strategic approach of the *Renewable City Strategy*, reducing building heat energy demand is the City's first priority, followed by the recovery of waste heat by, for example, using the heat from dishwasher water to preheat shower water or recovering heat from large computer data and server centres; finally, the remaining energy demand will be supplied by an increased proportion of renewable energy use. Actions to increase renewable energy supply and electricity generation will be considered after energy demand has been reduced.

BUILDINGS

To meet this hierarchy, the city's buildings may be broadly categorized as falling into two categories:

1. high density areas where space heat and hot water demand can be effectively served by a neighbourhood renewable energy system; or
2. lower-density areas where buildings' heat needs are lower and there is capacity to generate renewable energy on-site, or where renewable grid electricity is available.

Building Energy Use and Systems

Building Envelope

The building envelope is the fabric of the building, its walls, roof, windows, doors, etc.; the envelope is intended to keep weather out as well as manage heat and airflow, all in an effort to maintain a comfortable internal environment. Continual advances in both materials and building design are contributing to the development of new windows, insulation, and roofing that can significantly reduce heat loss, as can design changes that limit energy-inefficient features such as expansive glazing.

Building Systems

Building systems mostly consist of the heating, ventilation, and air conditioning systems (HVAC) as well hot water equipment. The building type obviously affects the size, nature, and complexity of these systems, including appliances and plug loads (like TVs, smartphones, computers, etc.), while some buildings also have more specialist systems like elevators, loading equipment, and server rooms. It can also be expected that home storage (batteries) will start to become an important component of future building systems.

Building and Neighbourhood Renewable Energy Options

Solar Energy (PV and Thermal)

Solar systems take the energy in sunlight to make either electricity (PV) or heat (thermal).

Photovoltaic (PV) Systems

A residential solar energy system uses solar modules, made up of photovoltaic (PV) cells, to harvest the sun's energy and convert it to electricity. A grid-tied system is the most common type of residential solar system. It allows the building to use its own solar-generated electricity, but when the PV system isn't producing electricity, such as at night, electricity is provided by the electrical grid. One of the benefits of a grid-tied system is that any excess electricity produced by the system can be fed back to the utility grid through a process known as net metering, a capability which already exists in BC.

The amount of energy that a PV system can provide depends on many factors such as the configuration and maximum size of the roof, its orientation, shading, and geographic location of the building. In Vancouver it's possible for a PV system to meet about half the current annual energy needs of a typical single-family home.

Solar Hot Water Systems

Solar thermal systems (also known as active solar systems or solar hot water systems) involve turning solar radiation into heat. Solar thermal collectors circulate a fluid which is heated by the sun's radiant energy. The heated fluid can then be pumped through a heat exchanger to provide space heating, although it is more common to use these systems for hot water. A solar hot water system can provide water-heating needs all year round. In the summer, solar-thermal systems can meet all the hot water needs, and in winter about 25% of the needs for a single family home. Given that hot water is the second-highest utility cost in a typical household after space heating, there is the potential to make significant energy improvements with solar thermal systems.

Wind

Small wind turbines are available that can produce enough energy to partially meet the electricity needs of a home; however, the larger the development, the smaller the portion of the total building load can be met by wind turbines. Small wind turbines are very different from large wind turbines. Large turbines, often grouped in wind farms, are widely used by utilities across Canada to provide electrical energy to electricity grids. Although home- or development-scale wind turbines may look like miniature versions of large turbines, there are important differences in technology, purchase decisions, technical suitability, and cost of generated electricity. For on-grid systems, small wind turbines can help supplement and reduce dependency on grid electricity. The largest challenge with on-site wind power is ensuring that there is enough wind to generate electricity and that that wind is consistent enough to support the financial investment. Wind power is an important consideration when looking to on-site energy generation, but its viability is very site specific.

Heat Pumps and Geoexchange

Heat pumps are devices that can take heat from the air or ground and use it to provide space heat or hot water. A heat pump is very much like a fridge running in reverse: rather than keeping a space cold, a heat pump can use the heat from outside air or the ground to keep a building warm or cool as needed and produce hot water. Heat pumps use electricity to move the heat from one place to another and have excellent performance characteristics. Domestic heat pumps are commercially available and already widely used to meet the complete space heat needs of homes and developments.

Geoexchange systems, sometime also called geothermal heat-pumps or ground-source heat-pumps, use the heating or cooling properties of the ground that make a basement warmer in the winter and cooler in the summer to heat or cool a building as required. The technology is commercially available today, but takes more advanced planning and construction techniques to lay the pipes that run through the ground to collect the heat. The upfront capital costs of geoexchange systems are more than those of conventional heating systems, but their operating costs are lower, leading to a total lifetime system cost that is lower.

Retrofit Incentive Program Quick Start: **The City will develop and implement a home retrofit incentive program**

The City will develop and implement a financial incentive program to support one- and two- family home owners retrofit their homes to reduce fossil fuel use and for the remaining energy help convert their heating systems to use technologies, like heat pumps, that can heat homes using only renewable energy. The City will seek to leverage funding through other levels of government and strategic partners to increase the reach of the program.

Neighbourhood Renewable Energy Systems

Neighbourhood renewable energy systems are local energy networks in which a neighbourhood energy centre generates heat that is piped to local buildings for space heat, hot water, and, in some cases, cooling. The system eliminates the need for each individual building to have its own boiler, hot water heating, and in some cases cooling equipment, and is more efficient. Such systems are widespread in northern Europe and have been used for decades. Vancouver's climate, well-designed buildings, and good construction quality mean that neighbourhood energy systems can be optimized to provide only space heat and hot water. The energy is typically distributed through a network of hot water pipes, which are efficient and compatible with a wide variety of renewable energy sources such as heat pump systems that recover waste heat from cooling systems and sewage, or clean wood waste. Some older systems use steam pipes to distribute energy to buildings—these systems can be converted from fossil fuels to renewable energy sources such as wood waste, but are not compatible with technologies that make use of heat pumps.

The inherent benefit of neighbourhood renewable energy systems is that their energy centres—where the heat is produced—can be updated and retrofitted to use the cleanest and best energy source available. Neighbourhood renewable energy systems also provide economies of scale to make use of renewable energy sources that are not cost-effective for an individual building to use. The neighbourhood renewable energy systems infrastructure platform does not lock a customer building into a certain energy source or set it on a path that cannot be changed at a later date. Regardless of the energy source for the system, neighbourhood energy systems can easily be built at the same time as new buildings are constructed, and the system can be expanded to meet growing need or replace old natural gas boilers. To be financially viable, neighbourhood energy systems need high-density development to ensure that the capital cost of the system is spread amongst users efficiently. In the case of these high-density developments, neighbourhood energy systems provide the lowest-cost solution—with utility rates that can be cheaper than conventional heating systems.

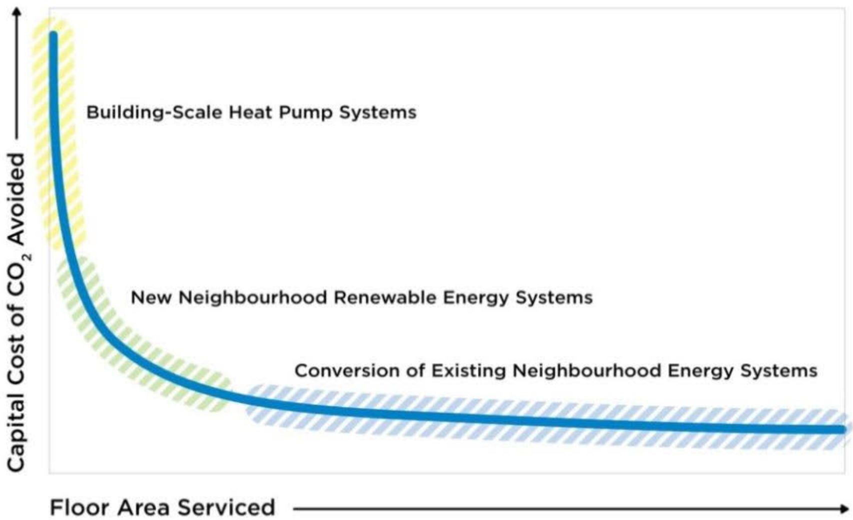


Figure 4 **– The Suitability of Neighbourhood Renewable Energy Systems to High Density Development**

Waste as an Energy Resource

So as not to encourage waste production as a means of increasing energy supply, materials should be managed according to the pollution prevention hierarchy in the B.C. Recycling Regulation, preventing reusable and recyclable materials from being sent for energy recovery. The *Renewable City Strategy* focuses on waste streams that originate from renewable resources, such as wood, food scraps and sewage. Non-renewable materials and waste streams will continue to be actively managed for the most responsible outcomes, but they will not be considered as inputs to the long-term renewable energy system of our future.

In many cases, there are already technologies that recover value from materials found in municipal solid waste. Anaerobic digesters produce biomethane from food scraps, clean wood combustion systems produce heat, and paper and plastics recycling allows the manufacture of new products. The City will work to expand the use of technologies that allow waste to be better utilized. The aim of the waste system is to avoid residuals – what's left after all the utility of a resource has been recovered - and residuals are likely to remain for the foreseeable future. With new technologies and management approaches, as it does now, the City will fully consider what these residuals are and how they will be disposed of in the most responsible manner.

Liquid waste can also provide a renewable source of energy. The City already uses sewage heat recovery in its Southeast False Creek Neighbourhood Energy Utility to provide heat and hot water to buildings in and around the Olympic village. The City will continue to explore future sewage heat opportunities, as well as work with Metro Vancouver to beneficially use the biomethane produced by the region's wastewater treatment facilities, which are owned and operated by Metro Vancouver.

Reducing Building Energy Demand

New Building Envelope Performance

The vast majority of non-renewable energy used in buildings in Vancouver is used to produce heat—typically through burning natural gas—and therefore reducing building heating demands is the foundation to achieving the City's 100% renewable energy target.

The initial focus must be upon the near-permanent elements of buildings—the envelope—because once constructed, building envelopes last a long time before they need significant updates or retrofitting. While lighting and appliances can reasonably be expected to change every 10 years or so, buildings do not have their windows changed or walls re-insulated nearly as often. Improving the energy performance of high-rise building envelopes after initial construction is even more challenging than for a single-family home. High-rise building retrofits require disruptions to, and potentially the need to temporarily relocate, large numbers of unrelated occupants for long periods of time; a single-family home retrofit has fewer people to coordinate and is likely quicker. Ensuring that buildings meet zero-emission standards from the time they are built with an initial focus on the building envelope, is the most effective way to ensure that buildings use as little energy as possible. As a result, the City is looking to accelerate the construction of zero-emission new buildings, while the City will seek to connect those large buildings that have already been built, and will still be standing in 2050, to a neighbourhood renewable energy system.

A zero-emission building is only viable if it is ultra-energy efficient, through the use of Passive House or ultra-low thermal demand design philosophies. With energy use substantially reduced, a zero-emission building can then meet its energy needs through either on-site generation or connection to an off-site renewable energy source like a neighbourhood renewable energy system or the electrical grid. Electrical power in BC is legally regulated to be 93% clean or renewable (and in recent years has been as much as 97–98% clean); however, using electricity for resistive space heat and hot water is expensive when compared to natural gas, which has halved in price over the last five years. Ultra energy-efficient buildings afford owners and occupants much lower electrical bills, avoid fossil fuel bills altogether, and do not overly burden the electrical grid. The use of resistance heat only makes sense when buildings meet ultra-low energy standards, and in many circumstances, heat pumps provide a better alternative to resistive heat. The design principles used to achieve ultra-low energy better manage not only building heating, but also building cooling mitigating occupant heat stress, particularly for vulnerable populations.

Civic Passive House Quick Start : **The City will support a Passive House or ultra-low thermal demand design philosophy for City buildings**

The City can help catalyze a change in building design through its consideration of Passive House or a low thermal demand approach as the default option for new City facilities. The City will investigate when the Passive House design philosophy and implementation is appropriate for City buildings and under which circumstances the approach does not currently deliver the best energy, greenhouse gas, occupant, and functional outcomes.

The City is about to trial the use of Passive House principles for one of its new fire halls. This will allow the City to better understand the opportunities Passive House can provide as well as increase the City's understanding of the design philosophy to better evaluate and introduce Passive House principles into the City's requirements for its own buildings.

As both new and retrofitted buildings start to incorporate more effective energy conservation principles, such as solar shading, solar orientation considerations, and the ability to generate their own power, the urban landscape will change. Building and neighbourhood design has never been static, and new designs will have to manage aesthetic appeal with the incorporation of design principles that support reduced energy use and increased energy generation and better allow buildings and neighbourhoods to cope with a changing environment.

Building Envelope Performance Retrofits

Buildings that have not originally been built to zero-emission standards will undergo some form of retrofit before 2050. That retrofit is likely to take place for one of two reasons:

1. some aspect of the building has reached the end of its useful life - the lighting, heating system or roof for example; or
2. the building owner feels that the building is in need of an update, so it will be more appealing to buy/rent, has lower energy bills, and so on.

In the first case, the rate at which lighting, appliances and similar components are replaced is much quicker than that for major components like walls, roofs or windows. For those components that are replaced sooner, global market forces are shaping efficiency improvements. The technology is improving rapidly and is easy to update – all you have to do is plug it in! Lighting, although not as easy to replace as appliances, is relatively simple to upgrade, and with the advances in LED technology, LEDs can be expected to meet almost all lighting needs by 2050.

For major components that have reached the end of their useful life and are replaced less frequently, it is possible to use the natural building renewal cycle to accelerate the rate at which zero-emission standards are met. When a building undergoes major retrofit it will have to be compliant with the zero-emission standards required of a new build. This in turn limits the energy demand that a neighbourhood renewable energy system would have to meet.

In the second case, where building retrofitting is desirable rather than essential, it is much more difficult to urge a building owner to undertake a retrofit that achieves deep energy reductions. In these cases approaches must be used that foster voluntary retrofitting, or mandate only modest retrofit requirements. In the cases the retrofit would require connection to a neighbourhood renewable energy systems in high density neighbourhoods, use of a heat-pump or on-site renewable energy generation (see below).

For both new and existing buildings poor system integration and optimization means that in the short-to-medium term maximizing the performance of the building envelope yields the best energy efficiency improvements.

Building Equipment Performance Requirements

The rationale for requiring the most efficient building equipment available at the time of construction or an upgrade to that standard at the time of retrofit is the same as that for the building envelope – act in the timeliest fashion to secure the most improvement. The hierarchy of building improvements prioritizes building envelope over building equipment upgrades, since building equipment upgrades are less enduring and realise smaller gains in overall energy performance.

Increase Building Renewable Energy Use

Expand Existing Neighbourhood Renewable Energy Systems

Energy efficiency improvements alone are not enough to achieve a renewable energy future; buildings must switch the sources of energy they rely on from fossil fuels to renewable sources. As such, the existing Southeast False Creek Neighbourhood Energy Utility system will be expanded to serve more buildings in the Southeast False Creek area and the False Creek Flats. Also, in accordance with the City's Neighbourhood Energy Strategy, the City intends to enable the establishment of additional neighbourhood renewable energy systems (see p.31 for more details).

The existing Southeast False Creek Neighbourhood Energy Utility uses waste heat from sewage to provide hot water to 4.2 million *sq. ft.* of buildings, with the system expected to expand to 7.8 million *sq. ft.* by 2022. City of Vancouver Council has already established through the Neighbourhood Energy Strategy (Energy Centre Guidelines) a preference for the use of waste heat (from sewers or cooling/refrigeration processes) to supply renewable energy to neighbourhood renewable energy systems, but if this isn't available renewable energy conversion options like the gasification and combustion of clean wood waste can provide a viable alternative.

Industrial Facilities' Transition to Renewable Energy

The City will continue to preserve its industrial lands to secure the long term economic strength of Vancouver. Such lands also have the opportunity to become significant renewable energy hubs through local and on-site generation, because of their significant amounts of roof space and underutilized land. The price of land, and its prominence on a business' balance sheet, is an important factor in moving Vancouver businesses to be more renewable. Vancouver cannot expand any further – it is bound on all sides. With land at such a premium, land values have been rising for the past decade and this trend is unlikely to change. Vancouver currently has little large or heavy industry, but that which does exist serves regional, national and international needs. Changing transportation patterns coupled with less favourable land economics are likely to mean that these heavy industries will have relocated outside the city by 2050.

The urban metabolism of the industrial sector in Vancouver is driven by the large number of light-to-medium industrial enterprises that service the city, for which there is an incentive to remain close to customers and not relocate out of the city. These businesses are the focus of preserving industrial lands within the city. The anticipated rise in energy prices will generate an incentive to become more energy efficient. Light- to medium- industry tend to own or lease equipment they use, which is the primary driver of their energy bills, as well as owning or having signed long-term leases for their premises. These businesses, even if they are not now, will become more energy aware as the cost of fossil fuels rise and that of renewable energy drops, and as they start to identify new business models driven by energy efficiency and renewable energy opportunities. Businesses are by their nature very effective at managing their costs, and the market changes in energy supply and equipment performance will drive change for these businesses.

Increase Building Renewable Energy Supply

New Neighbourhood Renewable Energy Systems

In 2012, Vancouver City Council approved the *Neighbourhood Energy Strategy* and *Energy Centre Guidelines*, which set the long-term vision for the development of neighbourhood renewable energy systems in Vancouver with a focus, beyond the expansion of Southeast False Creek, on the following areas of opportunity:

- Enable the conversion of the existing Downtown and Children's and Women's/Vancouver General Hospital campus steam heat systems from fossil fuels to renewable energy sources;
- Enable the establishment and expansion of new neighbourhood energy systems to serve high density areas in the Downtown, Cambie Corridor, River District and Central Broadway areas that are undergoing rapid development; and
- Enable the expansion of neighbourhood energy systems to replace boiler equipment in existing gas-heated buildings.

The strategy allows the City to provide leadership and support with the minimum of regulation the development of renewable energy systems that result in short-to-medium term low-carbon energy, long-term cost-competitive energy rates with the capability to be fully renewable, and stimulating green economic growth.

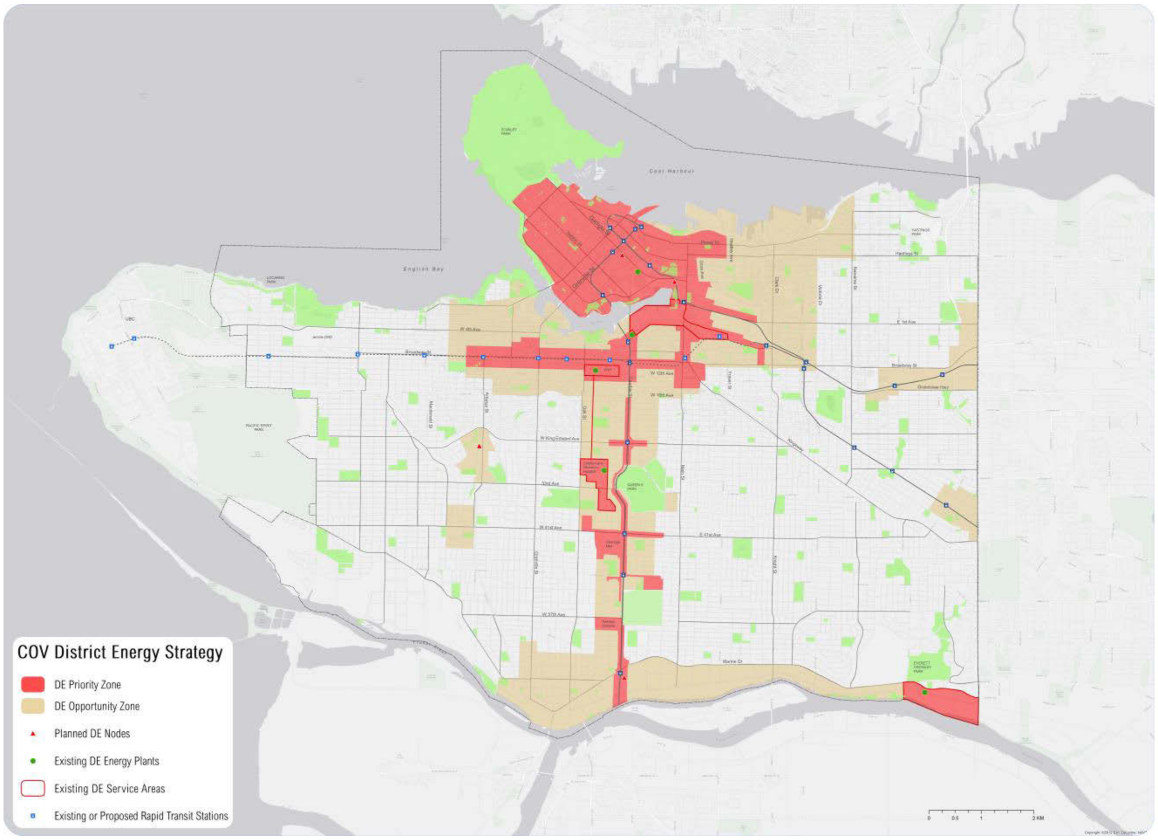


Figure 5 **– Neighbourhood Renewable Energy System Service Areas**

On-Site Renewable Energy Generation

Areas with low population density - those with a lot of single family homes or low-rise condos and apartments - do not use enough energy for heating to merit being connected to a neighbourhood energy system. The cost of building the system and then connecting to it is too high when spread between a small number of homes/units. As such, low density development must have its thermal needs (both space and hot water) switched from natural gas to renewable electricity from the grid or from on-site renewable energy generation.

Civic Renewable Generation Quick Start : **The City will support new renewable energy technologies for City buildings**

The City will actively consider new technologies, materials and approaches that support the strategic approach of the Renewable City Strategy. *For civic facilities that need retrofit or that are to be newly built the City will consider new and appropriate technologies that will enhance building performance, improve conditions for occupants and increase the use and/or generation of renewable energy.*

BUILDINGS

On-site renewable energy generation is more applicable to low-density sites since there is often space available on site to generate enough electricity and/or heat to meet the demand of a zero-emission building. On-site renewable energy generation can come from solar power or solar thermal, on-site wind generation, or heat pumps (that would likely use grid supplied electricity). With the anticipated improvements in building efficiency, and an already effective electrical grid the need for on-site rooftop solar power generation specifically will likely be determined by the market price of the technology, the cost to produce electricity and the larger system needs of the electrical grid. Unlike in many parts of North America, the comprehensive roll-out of rooftop solar PV is unlikely to be an imperative for success in meeting the City's renewable energy goals, but can give the public and businesses the opportunity to meet their own energy needs, yield a potential source of income through the sale of excess power, and provide a tangible way in which the people, communities and businesses can contribute to the move towards a renewably powered future. With wider uptake of distributed generation, on-site generation can allow buildings and neighbourhoods to be more resilient to disruption and outages, particularly during extreme weather events.

Solar Quick Start : **The City will streamline the process for the installation of rooftop solar systems**

The City will streamline the process to install rooftop solar systems to allow solar technologies to be implemented quickly as demand grows. The generation of on-site power and heat will play an important role in achieving the use of only renewable energy. Ensuring that renewable energy technologies can easily be implemented will be important in ensuring that market forces decide the most cost effective way to supply renewable heat and power.

Increasing Renewable Grid Electricity Supply

With current building practice Vancouver's demand for electricity can be reasonably expected to be about 8-10% higher in 2050 than it is today, although there would still be significant use of fossil fuels. Through significant energy efficiency and conservation efforts, the direction outlined in the *Renewable City Strategy* will enable Vancouver to make much wider use of renewable electricity while only increasing demand by about 20% over current levels, or 10% more than could be expected were current municipal and provincial policies maintained.

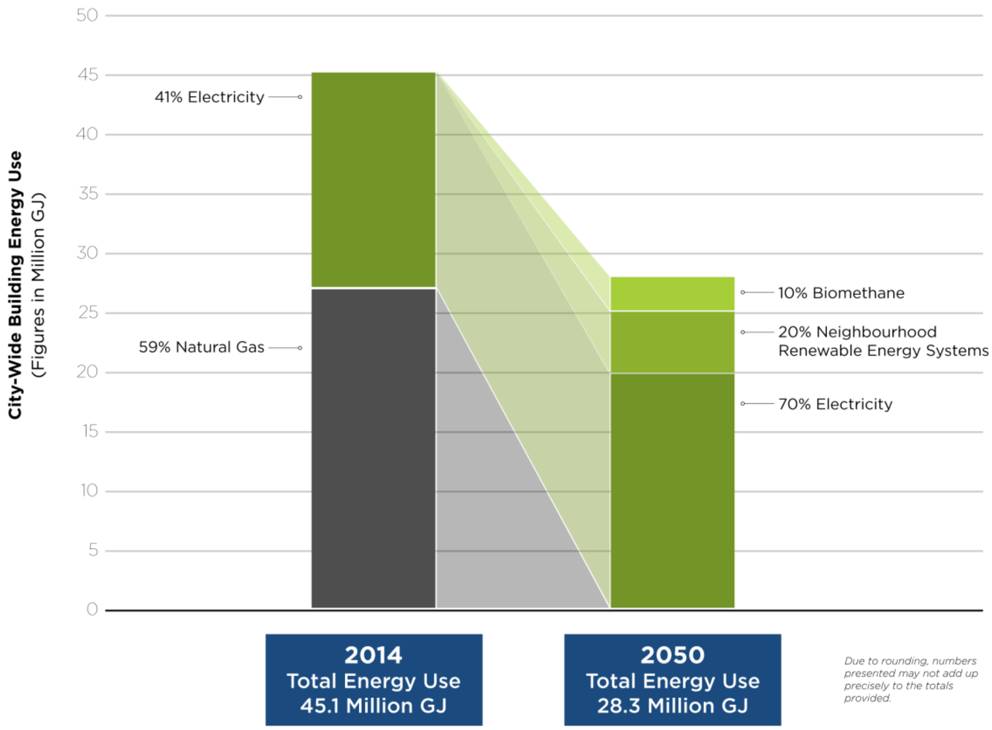


Figure 6 **– City-wide Building Energy Demand Reduction 2010-2050**

BUILDINGS

Across the province there is a need to increase grid-scale renewable electricity generation, not just for Vancouver. The attainment of 100% renewable energy use does not come solely through on-site generation. BC Hydro – the sole electrical utility supplying Vancouver – is legally required to develop *Integrated Resource Plans* (IRPs) to detail the utility's plans for meeting customer demand over the coming 20-30 years. Consistent with the *Renewable City Strategy*'s own strategic approach to reducing energy demand ahead of increased renewable energy use, the *2013 Integrated Resource Plan* details how BC Hydro intends to meet the *Clean Energy Act* requirement that 66% of electricity demand growth by 2020 be met through energy efficiency and conservation. The *Integrated Resource Plans* also detail grid transmission line improvements and the optimization of privately owned power generation facilities (called 'independent power producers', IPPs) to make better use of existing renewable power sources. The IRP also addresses new power generation needs for the short, medium and long term, and the City's goal to move to 100% renewable energy is consistent with many aspects of the Clean Energy Strategy section of BC Hydro's 2013 IRP. In response to the *Clean Energy Act* the IRP supports the use of renewable resources. The advances that have been made in wind and solar technology provide market-ready renewable energy technologies that are cost competitive with large-hydro power. Grid-scale renewable electricity generation of the future should be brought into service as it is needed and enhance system reliability, particularly in light of a changing climate, while also maintaining affordability. There is a significant economic opportunity for new business to come to BC and be headquartered in Vancouver as renewable energy resources are developed. Current regulation allows for up to 7% of the electricity used in Vancouver to come from non-renewable sources; the City will work with its utility partners to find ways to address that non-renewable portion, but in the event that the electricity supplied to Vancouver is not 100% renewable, the City of Vancouver will investigate how to secure renewable electricity from other sources. Also, in accordance with the City's *Neighbourhood Energy Strategy*, the City intends to enable the establishment of additional neighbourhood renewable energy systems that can provide heating, limiting the need for new electrical capacity to meet heating demands.

As there are increases in both on-site electricity generation and new grid-scale generation the electrical grid will have to adapt – the electrical grid will need to become "smart" to manage these new ways of generating and distributing electricity. The "smart grid" will not only better meet customer needs but also is imperative to managing emerging technologies like energy storage, electric cars, the 'home-ecosystem', and on-site power generation distributed throughout the city. A smart-grid is more reliable, more resilient when things do go wrong, and more adaptable to the future demands on the electrical system.

Ownership and Financing

The business case for significantly reducing energy demand and moving to renewable energy sources is good when the total cost of ownership, including purchase, maintenance and operation is considered. However, there is what's known as the 'split incentive', where the person or business constructing the building is not the one who owns and operates the building. This gives the developer no incentive to spend the extra money upfront to improve the building performance, since the developer is not paying the energy costs once the building is occupied.

In some circumstances the builder and occupier are the same entity; this is often true for institutional buildings like schools, hospitals, libraries and community centres as well as commercial, rental and non-market housing developments. In these cases it is important to accelerate the pace at which building energy performance improvements are realized in order to help make energy efficiency improvements common practice and more affordable, particularly given that in these same cases the owner/operator is often more tolerant of longer payback periods for their initial investment.

In cases where the split incentive persists, there is a need to develop new financing tools and energy equipment ownership models that can support longer payback periods or reduce the need for owner financing. There is also a need to develop business models that transfer ownership of the cost savings resulting from the efficiency improvements to the person or business that financed the system improvements.

Zero-Emission Building Priorities

B.1 New buildings to be zero-emission by 2030

Vancouver's *Zero-Emission New Building Strategy*, currently under development and expected to be considered by Council within a year, will focus on a number of core actions to move residential, commercial, industrial, and institutional buildings to be zero-emission.

B.1.1 Adopt and demonstrate zero-emission standards in new City of Vancouver building construction

When new approaches and technologies are first implemented, such as those integral to zero-emission buildings, it takes time for the market to adjust. Early adoption catalyzes innovation, learning and changes in the supply chain. The City and large institutions are well placed to lead these new approaches and technologies since they do not suffer a split incentive and are tolerant of longer payback periods.

B.1.2 Ensure rezoning policy leads the transition to zero-emission buildings

The City can foster leadership through its rezoning policy. On sites where the developer is seeking higher density, the City will require demonstration of green building leadership, but is first evaluating how to evolve these requirements to better align with its zero-emission building goals. Rezoned developments help advance new practices, technology and materials in the building market. Once there is sufficient understanding of the most effective approaches to achieving higher than minimum performance requirements, these approaches should become the new baseline (see *Priority B.1.4*). This requirement will remain for a limited period after the rezoning was granted, and thereafter the regular building code will apply. The greenhouse gas intensity targets that rezoned developments will have to achieve will become progressively more stringent, increasing the market share of buildings performing to higher and higher standards, so that by 2030 all new buildings will be zero-emission.

B.1.3 Incentivize and streamline the development of exemplary buildings

The City will develop new incentives to support the development of, and increase over time the market share of, zero-emission buildings. Incentives will especially focus on detached homes since there are no rezonings for this form of development. This approach will also help advance new practices and buildings that are delivering multiple City priorities (such as affordable housing). Part of this work will identify and remove policy and permitting barriers, since this will streamline desired forms of development that will showcase and provide case-study information on how to develop an exemplary building. Support for the certification and acceptance of new technologies and materials will help stimulate supply and allow new products to enter the market.

B.1.4 Establish and enforce specific greenhouse gas intensity limits for new developments

The City will adopt performance-based building standards. The City will work with the industry and trades to ensure that buildings comply with the code. The City will establish a stretch code route to achieve zero-emission buildings by 2030 with greenhouse gas intensity limits. The stretch code increments will be stepped to be more stringent over time as the market adapts to new technology and working practices; this will realise both energy efficiency improvements and increased on-site energy generation. Buildings will be able to comply with the regulations in a number of ways, and the market will best decide the most cost-effective compliance approach. It is expected that Vancouver's Building Bylaw will require zero-emission buildings by 2030.

B.1.5 Develop innovative financing tools to help fund new zero-emission buildings

Financing mechanisms and business models are needed to overcome the split incentive and deliver the cost savings that result from efficiency improvements to those who fund the work. These tools will bring together all the key stakeholders involved in new developments and building operation including, but not limited to, the utilities, financial institutions, developers, municipal and provincial government, and other private businesses. The financial tools will aim to connect the financial benefits of reduced energy costs to investors that are interested in covering increased capital costs in exchange for a long-term secure revenue stream that is based on these savings.

B.1.6 Establish partnerships to build industry capacity

New technologies require new working approaches - trades need time to adjust to the new technologies they are installing, supply chains need time to integrate new product offerings, and building operators need to adjust to new systems. As the market for renewable energy, ultra-efficient and zero-emission building technologies grows, projects will become better planned and standardized. This process must be accelerated. There is a need to train personnel and maintain the relevant professional and trade skills to deliver high-functioning buildings, skills which in some cases are new and in other cases are easily adapted from current practice and which provide low-barrier employment opportunities.

B.1.7 Mandate building energy benchmarking and labelling requirements

In order for building improvements to be effective at both the building and city-wide scales, building energy performance data are required. The City of Vancouver will work with other levels of government and other municipal governments to ensure that buildings are required to record and report their energy use. 'Energy benchmarking' would allow for the assessment of real-world building and system performance, as well as the opportunity to provide building labels that score the energy performance of the building, and to which a dollar-value can be ascribed at the time of sale.

B.2 Retrofit existing buildings to perform like new construction

In 2014, Vancouver City Council approved the *Building Retrofit Strategy* that is now being implemented and enhanced.

B.2.1 Use the Zero-Emission New Building Strategy *to reduce the need for building retrofits*

The faster new construction can move to ultra-low energy use and zero-emission the fewer buildings there will be that require future retrofitting to use only renewable energy. In addition, the energy efficiency requirements of Vancouver's Building Bylaw for a given building element (such as furnace efficiency, or insulation amount) for new buildings will also apply to those same elements. Having Building Bylaw requirements for ultra-low energy means that many buildings will gradually move closer to zero-emission as part of the natural replacement cycle for building equipment. This is especially true for building components that have shorter lifespans, since they will need replacing after zero-emission requirements come into effect, but prior to 2050.

B.2.2 Mandate energy efficiency improvements for existing buildings

The City currently requires modest energy performance improvements that are unrelated to planned renovation work. For example, a major bathroom renovation requires that the homeowner also weather seal their house if it is exceptionally drafty. These requirements will need to evolve as energy prices change and new technologies are developed, so that cost effective energy savings can be maximized. The requirement for energy improvements at the time of permit will remain and the city will also investigate additional upgrade triggers such as mandating the regular recommissioning of large residential and commercial buildings, or requiring improvement at the time of rental or ownership transfer.

B.2.3 Provide flexibility to achieve energy efficiency requirements through the support of on-site generation or neighbourhood energy system connection

In some cases it will be difficult to meet the energy efficiency requirements of Vancouver's Building Bylaw when undertaking a renovation – either due to physical restrictions because of the existing building design and form, or due to high equipment replacement costs. Under these circumstances the City will allow connection to a neighbourhood renewable energy system or the installation of on-site renewable energy systems that result in energy savings equivalent to those which would have been achieved by retrofitting the building to achieve the standard of Vancouver's Building Bylaw.

B.2.4 Facilitate modest retrofits through incentives and financial support mechanisms

To enhance the impact of energy utility programs and to fill gaps in program offerings, the City is investigating how to offer financial incentives and fund technical support programs to facilitate retrofits. These incentives and programs could be timed to allow industry capacity building ahead of regulatory requirements or to ease the burden of regulation for specific sub-groups or building types.

B.2.5 Increase renewable energy use by large energy consumers

There are already market-ready renewable energy options for large energy users such as industrial sites and high-rise buildings. These technologies cannot currently meet all of the buildings' energy demands at reasonable cost, but the City will investigate increasing the proportion of energy required to be met through renewable sources and the rate at which that proportion will change.

B.3 Expand existing and develop new Neighbourhood Renewable Energy Systems

In 2012, Vancouver City Council approved the *Neighbourhood Energy Strategy* and *Energy Centre Guidelines* that are now being used to guide the development of neighbourhood renewable energy systems in the city.

B.3.1 Expand existing Neighbourhood Renewable Energy Systems

Southeast False Creek Neighbourhood Energy Utility (SEFC NEU): The SEFC NEU, established in 2010, is the first system of its kind in North America that recovers waste heat from sewage. This system is growing rapidly, delivering low carbon energy at a neighbourhood scale, and is financially self-sufficient with cost competitive and stable customer rates. The lessons learned from this system have helped to inform the City-wide neighbourhood renewable energy systems approach, benefit other jurisdictions that are developing similar projects, and demonstrate the first neighbourhood renewable energy system in Vancouver.

In 2012 Vancouver City Council approved expansion of the Southeast False Creek Neighbourhood Energy Utility service area to include the Great Northern Way Campus Lands in the False Creek Flats area. Expansion work is now underway, with the relocated Emily Carr University to be connected to the system in 2016. The systems will also serve student housing, and residential and commercial buildings in this area will also be served by the system. The system is also well positioned to grow to serve new and existing buildings in the Mount Pleasant and False Creek South areas, and adjacent lands in the False Creek Flats.

River District: In 2012 a private neighbourhood renewable energy systems was established to service the River District neighbourhood. This system, which is currently using a temporary natural gas boiler, will establish a low carbon energy supply once there are sufficient customer buildings to establish a revenue base sufficient for the investment in a pipeline to recover waste heat from the existing Metro Vancouver Waste to Energy Facility located in Burnaby.

B.3.2 Enable the conversion the Downtown and Hospital Steam Systems from natural gas to renewable energy.

Downtown steam system: The privately owned downtown steam system serves more than 210 buildings and provides the single largest carbon emission reduction opportunity in the city. The City is working with the system owner to plan the conversion to renewable energy source. The conversion also has the potential to supply renewable energy to other neighbourhoods in Downtown, including Northeast False Creek, South Downtown, West End, Downtown Eastside and False Creek Flats via new low-temperature hot water networks.

Children's and Women's Hospital and Vancouver General Hospital campus steam systems: These systems are interconnected via an unused steam line. Reactivation of this steam line, and establishment of a new low carbon energy centre at Children's and Women's Hospital provides a significant opportunity to increase renewable energy supply to the hospitals. The system also has the potential to expand to serve new developments and existing natural gas heated buildings in the Cambie Corridor and Central Broadway areas.

B.3.3 Enable the development of new neighbourhood renewable energy systems for downtown and the Cambie corridor

There is significant work already underway to establish new neighbourhood renewable energy systems in high density areas of the city:

Northeast False Creek: Implementation is underway for a new neighbourhood renewable energy system to serve new developments in the Northeast False Creek area, via a low-carbon hot water expansion of the downtown steam system

South Downtown: Planning activities are underway to establish a new neighbourhood renewable energy system to serve to serve new developments in the area of the Granville Street Bridge.

West End, Downtown East Side, False Creek Flats: New high density development and existing natural gas heated buildings in these areas yield significant opportunities for new neighbourhood renewable energy systems, with further feasibility analysis and planning work to take place in 2016.

Cambie Corridor: This area has a number of large development sites, including Oakridge, Dogwood Pearson Lands, TransLink Bus Barns, RCMP site and Langara Gardens. Planning work is underway to establish an neighbourhood renewable energy systems to serve these areas

B.3.4 Continue to enforce and update as required, building and renewable energy supply policies that support neighbourhood renewable energy systems.

To ensure the viability of significant capital investments in neighbourhood renewable energy systems, it is important that there are sufficient buildings connected to the system. In 2007, the City established a bylaw compelling new developments in Southeast False Creek to connect to the Neighbourhood Energy Utility. Since then, as part of the neighbourhood planning processes the City has established connection rezoning policy for a number of areas, including the Cambie Corridor, Downtown Eastside and West End to name but a few. In 2015, Council approved but has not enacted the Neighbourhood Energy Bylaw, which provides greater clarity to developers in the Northeast False Creek and Chinatown areas. It is anticipated that, as systems are established in new areas, this bylaw will be expanded to secure the necessary customer base to facilitate capital investments in neighbourhood renewable energy systems and secure neighbourhood-scale low carbon outcomes.

Metro Vancouver, as the regional authority that controls liquid waste, in consultation with member municipalities (including the City of Vancouver), has developed a policy framework to enable the recovery of waste heat from its sewage system. The City will continue to apply the framework.

B.4 Ensure grid supplied electricity is 100% renewable

B.4.1 Partner with utilities to increase the supply of renewable energy

The City will work with its utility partners to increase the supply of renewable energy that is affordable and reliable and that increases the resiliency of the energy supply networks to Vancouver. The City of Vancouver will work with utilities to help develop their *Integrated Resource Plans* as required by legislation, and advocate for the inclusion of new renewable energy resources that maximize the renewable energy provisions in the *Clean Energy Act,* develop economic opportunity, and better meet the city's future energy needs. The City will work to ensure that existing renewable energy opportunities such as customer-based generation, net metering and BC Hydro's standing offer on clean electricity generation are maximized, as well as working to better understand the changes in electrical demand that will result from a transition to 100% renewable electricity.

B.4.2 Partner with utilities to implement a smart grid that meets Vancouver's energy needs

The City will partner with electrical utilities to implement improvements to the distribution systems within Vancouver, improve power quality and develop a smart grid that better meets customers' needs, optimizes electrical distribution to increase system efficiency, and improves reliability. The City will work to ensure that its role in distributed energy generation compliments utility efforts and initiatives to increase renewable energy supply. The City will also work with its partners to ensure that energy storage and smart devices seamlessly connect utility grids with future buildings and transportation needs.

A Vision of Vancouver's Building Energy Use in 2050

Modelling the supply of and demand for energy in Vancouver, as well as some select anticipated technological changes allows a feasible vision for the city's stationary energy use in 2050 to be developed. Below in shown how the strategic approach of reducing demand, increasing renewable energy use and increasing renewable energy supply can meet Vancouver's building energy needs in 2050.

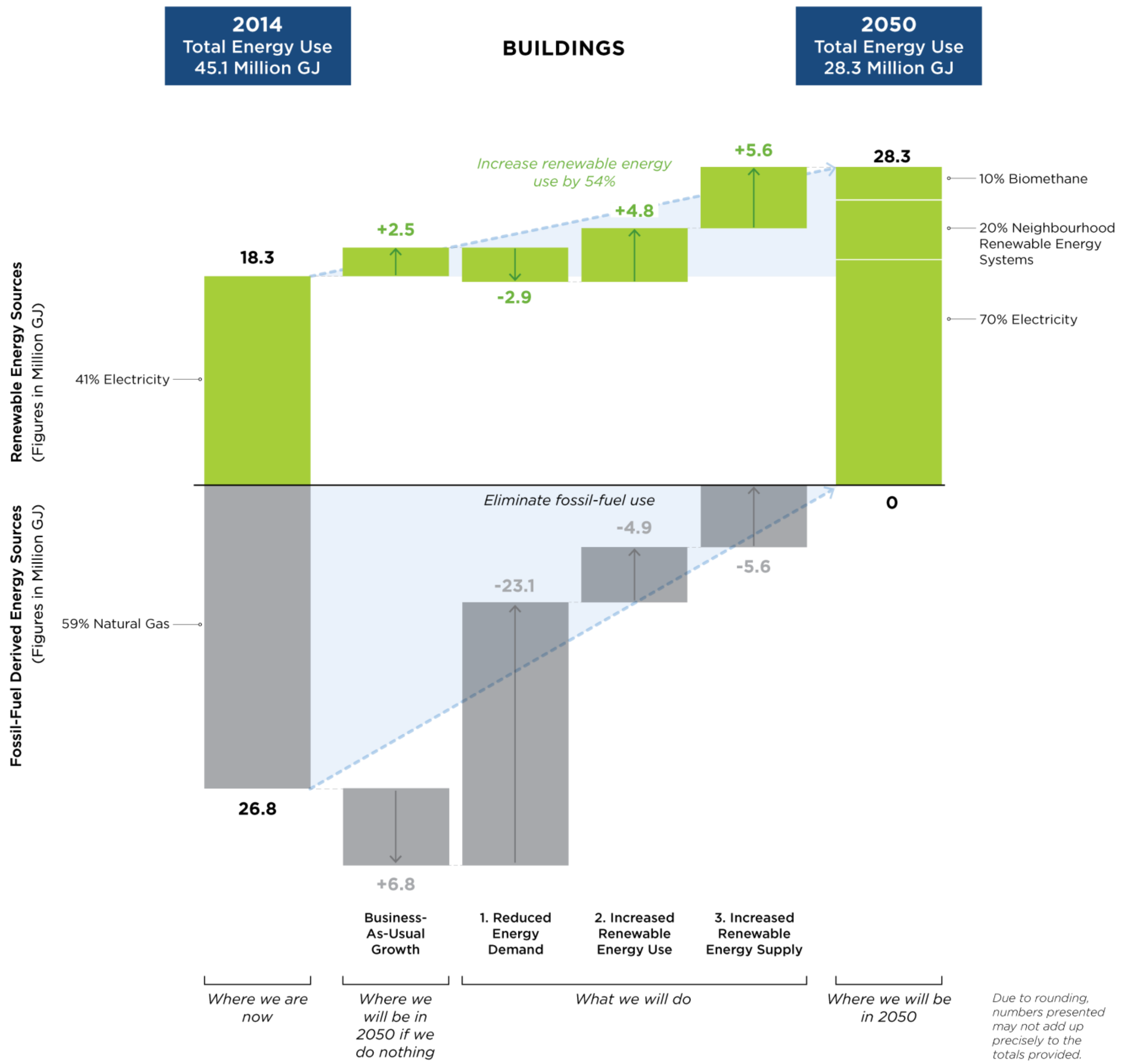


Figure 7 **– Building Energy Use Transformation 2014-2050**

The building energy priorities outlined above will feasibly allow Vancouver to grow and eliminate its dependence on fossil fuels. Improvements in building and appliance energy efficiency will allow the city to grow without dramatically increasing electricity demand by 2050. Vancouver has an active property development market compared to many cities. If historical trends continue, by 2050 about 40% of total floor space in Vancouver will have been built after 2020 and be zero-emission; about 30% of the floor space will have been built to current or upcoming building standards, while the remaining 30% will have been built prior to 2010. The implications are that almost half of the floor space in Vancouver will be zero-emission buildings, while the remaining half will have undergone a retrofit to bring them up to a similar standard.

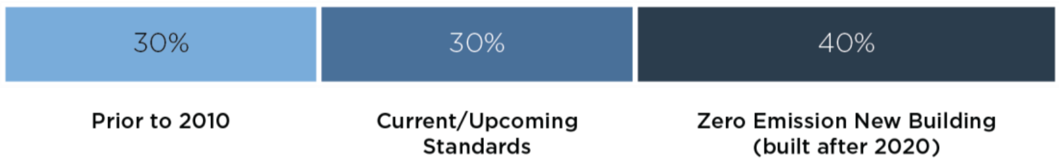


Figure 8 **– Anticipated City-wide Building Stock Age in 2050**

Of that total floor area, about 10% can reasonably be expected to use electrical resistance (baseboard) heat and hot water since come buildings aren't large enough to merit the efficiency advantages of a heat pump. About 20% of the floor area in the city will be serviced by neighbourhood renewable energy systems. The remaining portion will have heat and hot water provided through heat-pump technology, both air-source and geoexchange; local site design will determine to what extent these needs are met by on-site generation or by renewable grid electricity.

City-wide building energy demand could be reduced by over a third compared to 2014 levels through: adopting zero-emission buildings; requiring that buildings that undergo retrofit attain a similar level of performance; and connecting buildings to neighbourhood renewable energy systems. Of that energy demand which does remain, about 70% can be met through renewable electricity (both on-site and grid supplied) which constitutes about a 10-15% increase in building related electrical demand compared to today; about 20% of total building energy demand will be met through the city's neighbourhood renewable energy systems, and 10% through biomethane. Biomethane is currently a limited resource, and is likely to remain so as demand for it increases. As such, biomethane for space heat is not the best long-term use of the resource, and it is expected that biomethane will be used most extensively in the commercial freight sector for its high energy content and easy of transport. However, in the short-to-medium term biomethane affords a ready opportunity to decarbonize building space heat and hot water for those that are currently using natural gas.

As building performance improves there will be a change in the building energy end uses that demand the most energy. Across the city as a whole, accounting for population growth to 2050, home appliance energy use can be expected to stay constant, with LEDs expected to cut residential lighting needs by as much as 80%, while air conditioning load will have increased by about 75%. There are two areas of significant load growth, although significant for different reasons. Plug loads like TVs, smartphones, microwaves and so on are expected to more than double, increasing the share of total residential building energy demand associated with plug loads from 16% to 36%. The need to charge electric vehicles is significant in that is it a 'new' electrical demand for buildings, but the scale of the demand increase is itself small accounting for only about 5% of total building energy demand across the city. This value may at first seem low, but given that a with current vehicle batteries a full charge allows a vehicle to travel about 150*km*, and daily commutes are 10-30*km*, the energy demanded to fully recharge the battery each day is small.

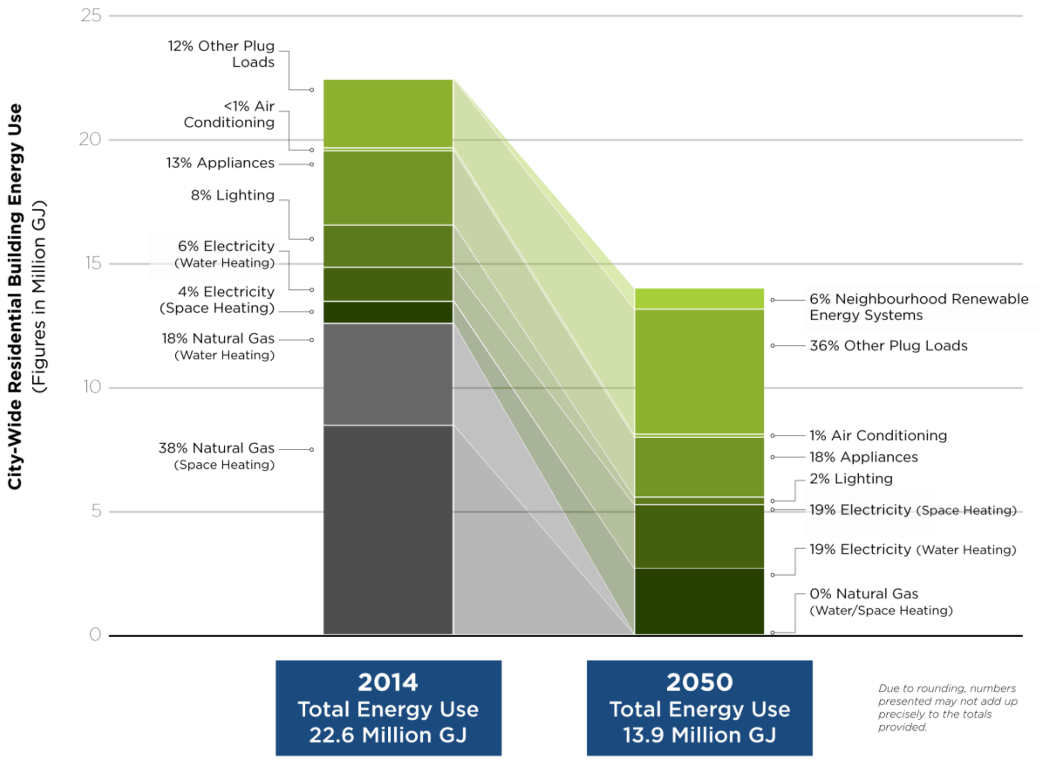


Figure 9 **– Vancouver Residential Building Energy Use by End-Use 2014 and 2050**

The large reduction in building energy use will also lead to a growing importance for the embedded carbon and embedded energy associated with building construction. As the implementation of the *Renewable City Strategy* progresses, a move toward full life-cycle building considerations will be inevitable.

Industrial, institutional and commercial buildings will see plug and equipment loads increase by about 20%, and a reduction in lighting energy demand of about one-third through the use of LEDs. The most significant energy savings can be expected from HVAC systems that will, in aggregate by 2050, use about half the energy than they did in 2014. Non-residential connections to the city neighbourhood renewable energy systems will displace significant amounts of space heat and hot water needs that would otherwise have been met through biomethane. Direct biomethane use is expected to account for about 10% of industrial energy use, while the neighbourhood renewable energy systems may also use biomethane to produce heat. In total, industrial, institutional and commercial buildings, systems and equipment improvements can be expected to cut city-wide energy use for the sector by about 35%.

BUILDINGS

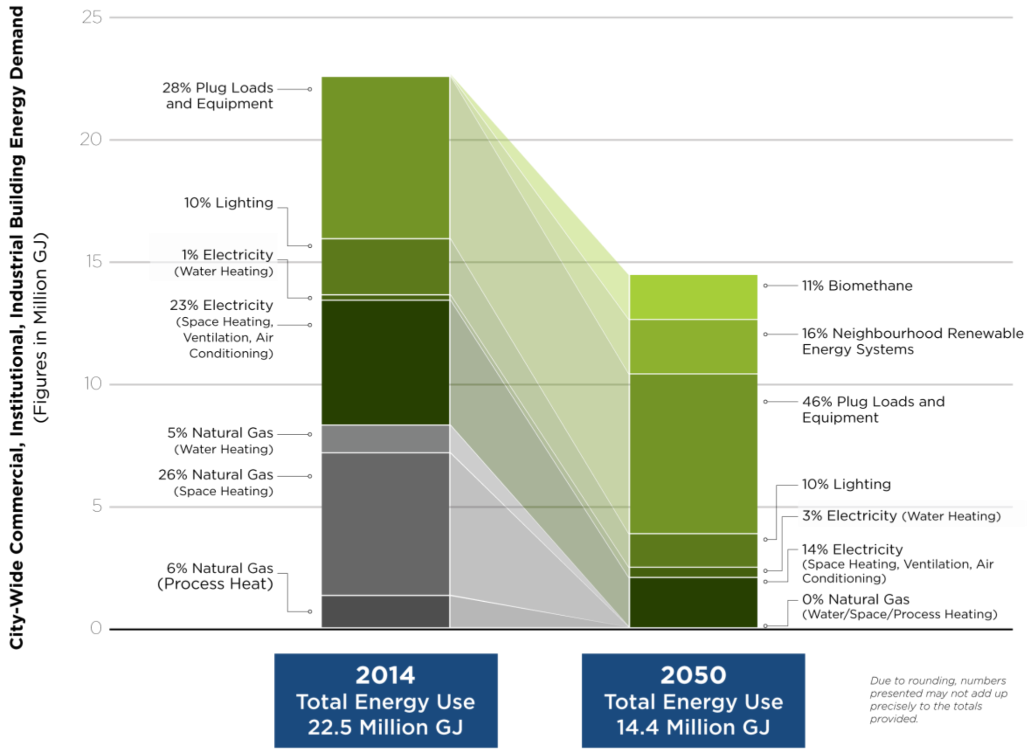


***Figure 10* – Vancouver Industrial, Institutional and Commercial Building Energy Use by End Use 2014 and 2050**

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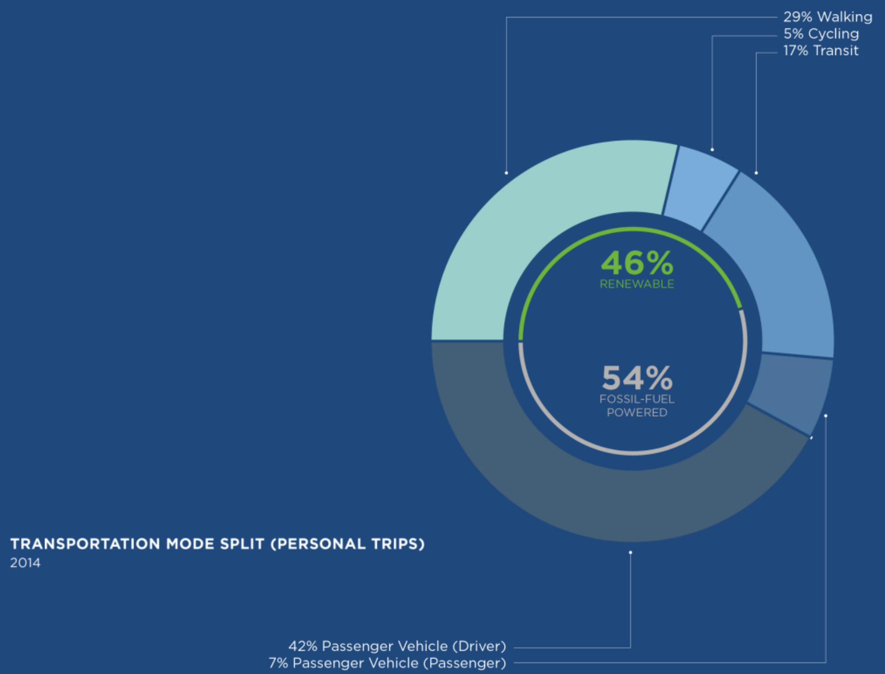
Summary :: Achieving Renewable Transportation in Vancouver

Imagine a city where the transportation system is efficient, supports a thriving economy while increasing affordability, provides citizens the opportunity to be healthy and mobile, and which is powered by renewable energy.



Renewably Powered Transportation Priorities

To increase the proportion of renewably powered trips from that shown in the pie-chart above for 2014 Vancouver will:

T.1 Use land-use and zoning policies to develop complete compact communities and complete streets that encourage active transportation and transit

- T.1.1 Foster land use as a tool to improve transportation consistent with the direction established in *Transportation 2040*
- T.1.2 Enhance and accelerate the development of complete streets and green infrastructure
- T.1.3 Enhance the pedestrian network according to the direction established in *Transportation 2040*
- T.1.4 Enhance cycling infrastructure and encourage more bike trips according to the direction set in *Transportation 2040*
- T.1.5 Use parking policies to support sustainable transportation choices and efficient use of our street network.
- T.1.6 Optimize the road network to manage congestion, improve safety, and prioritize green transportation.

T.2 Improve transit services as set out in *Transportation 2040*

- T.2.1 Extend the Millennium Line in a tunnel under Broadway
- T.2.2 Improve frequency, reliability, and capacity across the transit network
- T.2.3 Develop a transit supportive public realm with improved multimodal integration and comfortable waiting areas
- T.2.4 Work with the transit authority and other partners to transition fossil fuel powered transit vehicles to renewable energy

T.3 Transition light-duty vehicles (cars and light trucks) to be predominantly electric, plug-in hybrid or sustainable biofuel powered

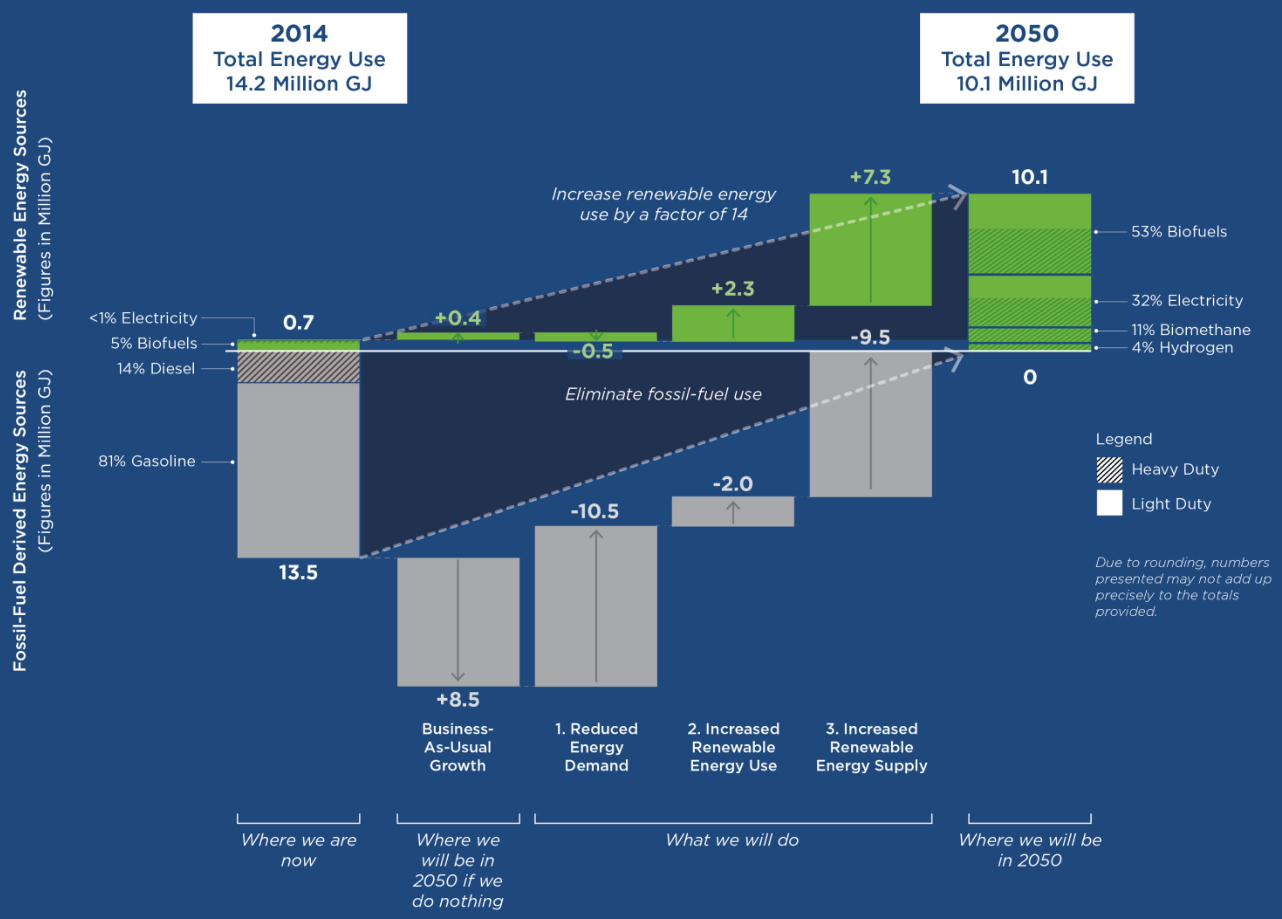
- T.3.1 Develop vehicle and fuel standards to support renewably powered vehicles
- T.3.2 Develop supporting infrastructure that meets the needs of renewably powered vehicles

T.4 Develop car-sharing and regional mobility pricing to encourage rational journey choice

- T.4.1 Support increased car-sharing and the uptake of renewably powered vehicles in car-sharing fleets.
- T.4.2 Advocate for comprehensive regional mobility pricing

T.5 Better manage commercial vehicle journeys and transition heavy-duty (commercial) vehicles to sustainable biofuels, biomethane, hydrogen and electricity

- T.5.1 Improve the delivery of commercial freight, goods, and services according the direction set in *Transportation 2040*
- T.5.2 Work with fleet operators and contractors to transition to renewably powered vehicles



A Vision for Vancouver's Transportation System in 2050

Vancouver will continue its efforts to build a city that is compact and complete, allowing most people to meet their daily needs through walking, cycling, and transit. Longer journeys will be made on transit that is predominantly electrified, complemented by renewable fuels like sustainable biofuel, biomethane, or hydrogen. The number of people living and working in the city will grow significantly by 2050, and while the number of private vehicles per person could decline by as much as 15%, the total number is expected to increase by 15%. Even with this growth, the actions outlined in the *Renewable City Strategy* - including thoughtful land use planning and infrastructure investments that improve green transportation options - could reduce total annual vehicle kilometres travelled by 20% over 2014.

The *Renewable City Strategy* priorities will help transition private vehicles to using only renewable energy sources. By 2050 about 25% of Vancouver's personal vehicles would be electric using renewably generated electricity, 45% plug-in hybrids using renewable electricity and sustainable biofuels, and the remainder conventional hybrid vehicles running on sustainable biofuels. The compact nature of Vancouver means daily commutes are short enough to allow the vast majority of plug-in hybrid journeys to use only the vehicle's battery. Given the anticipated growth in both electric and plug-in hybrid vehicles, it will be critical to provide charging infrastructure at home, work, and on-the-go locations. The effect of autonomous cars on our transportation system is expected to be marked, although it is unclear if the effect will in aggregate be positive or negative.

As fewer people drive for personal trips, the proportion of transportation energy attributable to commercial vehicles will increase. Less important than the number of commercial vehicles is the distance they travel and the weight of goods they haul. Improving how goods, freight, and services are provided will be paramount, although it is as yet unclear if electrification, biofuels, biomethane or hydrogen will dominate heavy-duty vehicle types.

TRANSPORTATION :: Making Transportation Renewable

Imagine a city where the transportation system is efficient, supports a thriving economy while improving affordability, provides citizens the opportunity to be healthy and mobile, and which is powered by renewable energy.

How Vancouver Moves

As a community our transportation choices shape our city and ourselves. The ease with which we can move around determines how we spend our time each day, where we can go, who we can see, and what we can do. Our transportation choices impact our health and well-being as well as the quality of our air. Vancouver is a multi-modal city where most citizens use a combination of walking, cycling, transit, and motor vehicles to get around and meet their needs.

Our transportation system moves more than people - it also moves goods and services that are essential to a thriving local economy and high quality of life, requiring efficient local networks and connections to the larger road, rail, air, and marine networks.

Transportation and land use are inextricably linked - how we design our communities affects our mode choices and how much we travel. Those travel needs in turn influence how we use land. *Transportation 2040*, the City's strategic transportation plan, establishes a clear hierarchy of transportation modes that are consistent with the strategic approach of reducing the need for motorized transport, and prioritizing walking, cycling, and transit as the city's top transportation choices.

Vancouver continues to be a sustainable transportation leader in North America, building on past successes and pioneering emerging concepts to enhance green mobility and accessibility. Vancouver has already reached its 2020 mode share target that at least 50% of all trips originating in the city being on foot, bike, and/or transit, climbing from 40% in 2008. Over the same time period the number of daily bike trips doubled from 50,000 to 100,000 per day.

Numerous projects have contributed to this success. In particular, the opening of the Canada Line rapid transit line in 2009 resulted in a large increase in transit use. Land use and urban design play an important part. We continue to build mixed-use, walkable communities that are well served by transit. The City has also taken a new approach to cycling with an increased focus on low-stress bike facilities that feel comfortable for people of all ages and abilities.

Additionally, Vancouverites have embraced car sharing more than any other city in North America, with services rapidly expanding and now including one-way services. Car sharing makes it easier for people to embrace a multi-modal "car-light" lifestyle that doesn't require owning a car.

To continue to make progress on these achievements, the City needs support from outside agencies. One million people will be added to the Metro Vancouver region in the next 30 years, or about 35,000 people per year. The transit system is largely at capacity and requires significant support and funding from higher levels of government in order to meet increasing demand. The regional Mayors' Council *Transportation and Transit Plan* details the projects necessary to reach our mode share targets, but stable, long-term funding sources are required to deliver them.

Automobiles, while declining in terms of mode share, will continue to play an important role in our transportation system for the foreseeable future. Autonomous vehicles, in particular, could radically change how we get around, and at the moment their future effect, both positive and negative, is unclear. To meet our long-term air quality and emissions targets, it is important to support the shift to renewably powered vehicles.

Adapting to a Changing Transportation System

Road transport accounted for about 37% of Vancouver's total emissions in 2014 and that's because the way we use and think of transport has been established over a century. That car-centric mindset is slowly changing but not without challenges. Many key actions—to improve the pedestrian realm, build a complete and attractive cycling network, improve transit capacity and reliability, and create vibrant public spaces—will require further road space reallocation from the private automobile. The emergence of information technology and systems to manage our journeys and make them easier has already begun, and can be expected to grow even more. The actions laid out in *Transportation 2040* and the direction set by the *Renewable City Strategy* outline the steps needed to ensure a smooth transition away from auto dependency.

Vancouver has to date, through a clear transportation vision, been successful in ensuring that people, goods, and service can travel efficiently. The City's success has come from comprehensive partnerships, regional planning, and close cooperation between different municipal departments. Reimagining what road space is used for has led to development of "complete streets" that provide mobility and public space options for a wide variety of street users, changing how we move, alleviating congestion, and allowing Vancouverites to take important steps to improve their health. The transportation system that Vancouver is aiming for is not one where freedoms are given up at the expense of environmental benefit, but one where people make sustainable choices because they are the most rational, comfortable, convenient, safe, and enjoyable ways of getting around.

Preferential Parking Quick Start: **Support the uptake of renewably powered vehicles through preferential parking provision**

Parking provision and management is an important determinant of how we use our vehicles. Through the provision of preferential parking for clean vehicles it is possible to catalyze the uptake of clean vehicles as people see tangible benefits to ownership. As the transition becomes more complete there will be a need to reassess how preferential parking is managed.

Reduce Motorized Transportation Demand

Land Use and Urban Design as Renewable Energy Tools

Focusing on the factors that affect Vancouver's transportation choices promotes the design of communities that facilitate the transportation hierarchy. *Transportation 2040*'s "5D's" of the built environment- destinations, distance, density, diversity and design are core considerations in ensuring our communities are complete and well connected. Our transportation choices depend on a variety of factors, including travel time and reliability, marginal cost, how far we have to go and how flexible we need that journey to be. For example, do we have things to carry, are we in a rush, are we meeting people, is parking available close to the destination, and will we have to pay for it?

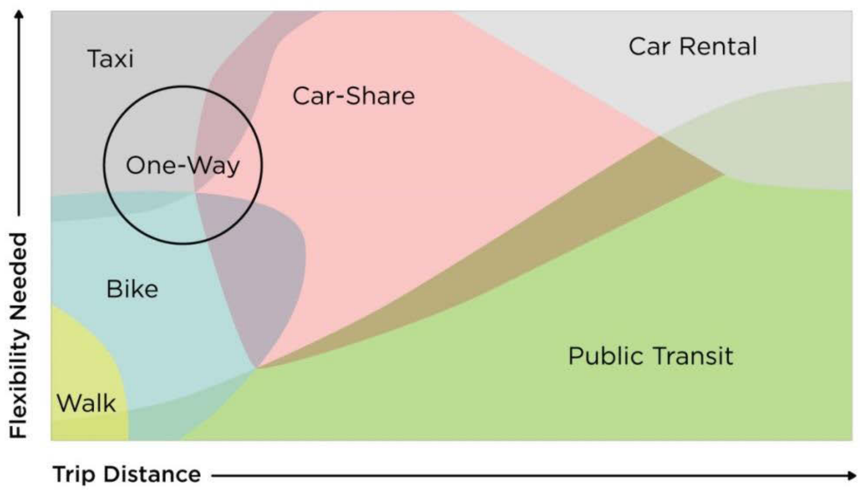


Figure 11 **– Journey Mode Choice According to Distance and Required Flexibility**

Several principles underlie the *Regional Growth Strategy* and the City's own *Regional Context Statement*, including:

- Ensuring that Vancouver has a compact urban area to promote energy conservation and efficiency;
- Delivering a sustainable economy that is both local and international and not bound to fossil fuels;
- Effectively protecting the environment and responding to climate change through use of only renewable energy sources; and
- Developing complete communities that rely less on personal motorized transport.

Vancouver is an urban planning success story that has fostered livable densification, first in the downtown and now throughout the city. Vancouver is a city of unique neighbourhoods, which, although diverse, are working toward a set of common goals that underpin what a 100% renewable energy city can achieve:

1. Creation of an urban form that is environmentally sustainable;
2. Development of a range of affordable housing options to meet a diverse set of needs;
3. Contributing to a robust and diversified economy, which as a result is resilient;
4. Support for communities that enhance culture, heritage, and creativity;
5. Development of sustainable transportation options that are not just viable but preferable;
6. Enhancement of public open spaces, parks, and green linkages;
7. Promotion of resilient, sustainable, safe, and healthy communities.

In delivering these goals, the City is committed to upholding the highest standards of urban design that makes our streets and cityscape attractive, functional, memorable and safe. Through the integration of parks, open spaces, sidewalks, walkways, bodies of water, trees, landscaping and lighting the city can match the urban fabric of the city to the needs of a renewable transportation system.

Underway Now: **Replace the Georgia and Dunsmuir viaducts for better at grade services and public space**

Removing the two elevated roadways that connect the False Creek Flats to Downtown will repair a major gap in the Vancouver's urban fabric, improve walking and cycling, create new open space and increase land for housing including affordable housing. The City has already completed initial feasibility and design work based on public input and continues to work on the Northeast False Creek Conceptual Plan and Northeast False Creek: Directions for the Future.

Increase Walking

Walking will continue to be the City's top transportation priority. Almost every journey has a walking component to it at some point. For short trips, walking is the best option for people and the environment, and businesses benefit from passing customers. Vancouver's grid network, good urban planning and pleasing urban design mean walking trips are often direct, convenient and interesting. There is still more that the City can do to make walking more appealing and safer. As part of its *Transportation 2040* efforts, the City is taking a comprehensive approach to address gaps in the walking network, improve sidewalk connectivity, create more temporary and permanent public spaces, and maximize accessibility for those with visual or mobility impairments.

Underway Now: **Improve the False Creek bridges to support active transport**

The False Creek Bridges are currently unpleasant to cross on foot or by bike. City staff are working on conceptual designs to reallocate vehicle road space to walking and biking following steadily reducing vehicle numbers on the bridges. City staff are currently developing conceptual designs that will be considered by Council once complete.

Increase Cycling

Cycling creates no emissions, is inexpensive, improves health and allows easy access to much of Vancouver. It is often the fastest way to get around for short-to-medium length trips, with many destinations accessible by bike within 20 minutes. There is also increasing evidence suggesting that cycling, similar to walking, is good for local businesses.

While cycling is growing in popularity, many people are discouraged from riding because it seems dangerous or impractical. To reach a wider audience, the City is focusing on building a direct, intuitive network of routes that efficiently connect destinations and are comfortable for everyone, including families with children, the elderly, and novice riders. Providing more secure, convenient, and abundant parking and end-of-trip facilities like showers and change rooms is also important, as is promotion and education to encourage cycling as an everyday, normal activity.

Underway Now: **Implement a public bike-share system**

The City of Vancouver is committed to implementing a public bike-share system. The City has made efforts to implement a financially prudent and viable bike-share system and is committed to working with its private sector partners to deliver a bike-sharing service by 2016.

Increase the Use of Renewable Transportation Options

Increase Transit Use

The city's compact urban form is complemented by our comprehensive public transit system. TransLink is the local transit authority, and has a shared responsibility with the local municipalities and regional government to deliver multi-modal transportation options including management of the major road network and regional cycling infrastructure. A large portion of the transit service in Vancouver is already electrified through the use of SkyTrain (electrified light rail) and trolley buses, but there are still diesel bus services on many of the routes that either do not have trolley infrastructure or need to have the ability to pass other buses (trolley buses cannot pass one another without additional infrastructure). Meeting the City's 100% renewable energy goals will require expanding the trolley network and/or converting these non-electric routes to other fuel sources. This will not only reduce carbon emissions but significantly improve local air quality and protect our health.

Increase Shared Vehicle Journeys

Car sharing is a membership based service that gives access to a fleet of cars which can be rented. Fees are typically charged on a distance- or time-based rate, sometimes with nominal fixed membership fees. This fee structure typically allows people to go 'car light' or even 'car-free' and save money compared to owning their own vehicle, yet still maintain the flexibility of car ownership. Car-share companies have varying service models; some allow the user to pick up and drop off the car anywhere within the city, called one-way car-share; others require the vehicle to be picked up and dropped off at the same place, called return-to-base car-share. Some companies have a range of vehicle models, while others use only a single type. These differences encourage people to have multiple memberships to meet their exact journey needs. A single car-share vehicle can replace up to 11 personally owned vehicles, freeing up road space for other uses. The already-significant ability of car-sharing to cut energy demand from transportation is further enhanced through the potential of using renewably powered cars in car-sharing fleets.

Increase Renewably Powered Personal Vehicle Choice

Personal vehicles will continue be an important part of the city's transportation mix, and even with significant gains in active transportation, it is critical to support increased vehicle efficiency. With the exception of the electrified SkyTrain and trolley buses in Vancouver, today's transportation system is almost exclusively based on the combustion of gasoline and diesel. The transportation system of the future will have a greater range of energy sources and vehicle types than are common today. The various vehicle types will meet different transportation needs, from those of the individual passenger to light commercial and long-distance freight.

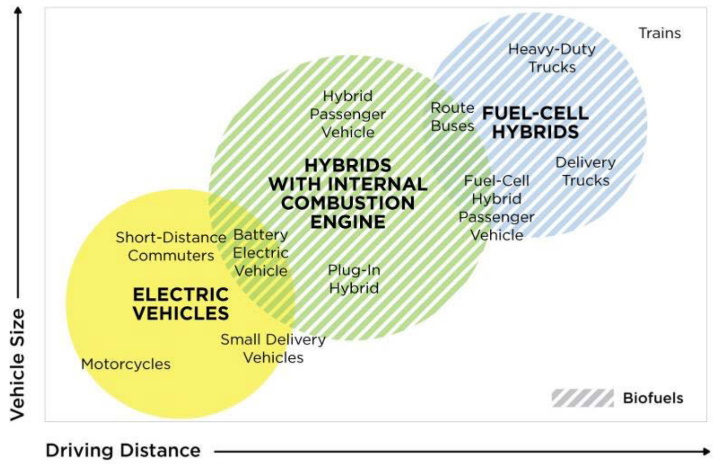


***Figure 12* – Vehicle Suitability for Different Journey Needs**

The transport system is expected to evolve so that, most short-distance and local journeys will be made on foot or bike, most longer trips by transit, and those remaining using electric vehicles of various types, depending on the needs of the journey. Electric vehicles already have ranges that are ample enough for peoples' everyday use. If drivers need to make longer journeys that cannot be served by the range of battery technology or where battery technologies are not cost efficient, alternatives like hydrogen and biofuels will need to be considered. Vehicles already available today called plug-in hybrid electric vehicles combine a battery and regular engine, so that for short distances the car acts like an electric vehicle, and when the battery runs flat a regular engine takes over. For those people who regularly travel long distances, renewable fuel solutions will come from liquid biofuels and renewable hydrogen fuel cell vehicles. Similar solutions can also be expected for larger vehicles like buses and trucks.

Based on uptake for hybrid vehicle technology, the last big change in vehicle technologies before the current boom in electric vehicle sales, it will take between 15 and 20 years to see significant changes in automobile fleets, and about the same amount of time again for technologies to be adopted into the early core market. This means that although vehicles tend to be replaced every seven to ten years, the longer time needed for widespread changes means action must start now, particularly to support technologies that are becoming commercially viable.

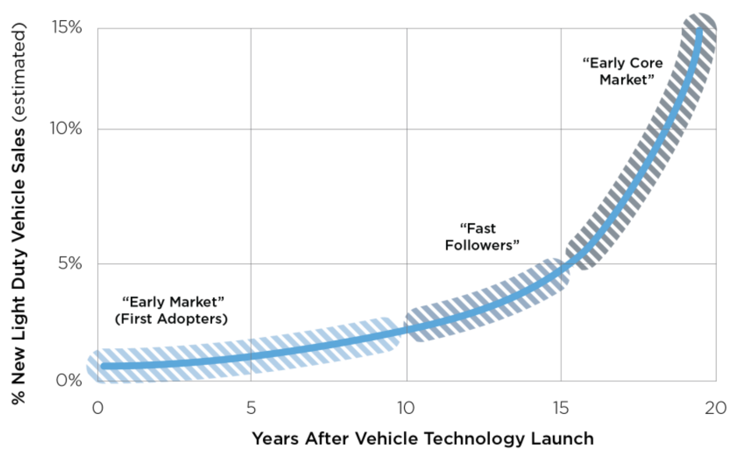


***Figure 13* – New Vehicle Technology Uptake Times[2]**

[2] Adapted from hybrid electric vehicle launch trend graph, California Environmental Protection Agency

Battery Electric Vehicles

Battery electric vehicles, often just called electric vehicles, have an on-board battery that is charged up to drive an electric motor which moves the car. Electric vehicles have started to become widely available in the last few years, and with lower maintenance and fuel costs than regular vehicles their sales are growing steadily. Electric drive systems are also being demonstrated for light-trucks. Current battery technology allows a moderately priced electric vehicle to travel about 150*km* on a single charge, although some more expensive models can reach more than 400*km*, and this is expected to become much more widely available as battery technology matures and battery prices decline. That maturity is making batteries smaller, cheaper and able to store more power; but it's unlikely that batteries will ever be able to complete with liquid fuels for long journeys. electric vehicles make ideal urban vehicles, and given time to develop will suit some light-truck needs also. The time to charge the cars' battery is still significant, but new technologies are reducing that charge time.

Electric Vehicle Infrastructure Quick Start: **Develop and implement an electric vehicle infrastructure strategy to accelerate electric vehicle uptake**

The City will develop a comprehensive electric vehicle infrastructure strategy to support the development of electrical infrastructure to charge electric vehicles and accelerate their uptake. The electrification of personal transport will require new infrastructure to support the charging of electric vehicles and plug-in hybrids. That infrastructure will mostly be required at home, but will also be needed to support workplace charging and charging while out and about. The strategy will address how to expand the provision of charging infrastructure in both new and existing buildings where there are clear routes to doing so, while also identifying strategic partnerships to solve challenges where no immediate solution is apparent.

Plug-in Hybrid Electric Vehicles

Plug-in hybrid electric vehicles have a battery *and* a combustion engine. The battery is charged by plugging in the car, just as you would for an electric vehicle, and the car can then be driven using only the battery. When the battery runs flat, the regular engine starts and the vehicle uses that to get around. If the regular engine is fuelled using biofuels (see below) and the battery charged using renewable electricity, plug-in hybrids are a renewable way to get around. Plug-in hybrid electric vehicle technology is currently suited to cars of all sizes, but can be expected to diffuse into light trucks also. Plug-in hybrid cars are just becoming available in Canada but have seen huge growth in Europe where they have been available for longer. Through the combined use of the battery and engine, the vehicles have a range the same as today's cars.

Hydrogen Fuel Cell Vehicles

Hydrogen fuel cell vehicles use a fuel cell to convert hydrogen into electricity, which then drives an electric motor. Unlike an electric vehicle or plug-in hybrid electric vehicle, the car does not have a battery; the hydrogen itself is stored in the car and converted into electricity when it's needed. The first commercially available fuel cell vehicles are starting to become enter the market, particularly in California, although they are not yet widely available in Canada. Hydrogen fuel-cell technology is well suited to medium-to-large cars and light-duty trucks. Since hydrogen is a gas it must be compressed and stored in a high-pressure tank. This means the car's fuel system is a little more complex, but results in a range and refueling time similar to today's cars.

Increase Commercial Vehicle Technology Options

Commercial vehicles cover a large range of vehicle types from light trucks to buses, garbage haulers to large articulated trucks. For each particular vehicle type the technologies listed below could be used, although the larger the vehicle the less suited to complete electrification it is likely to be.

Biofuel Powered Commercial Vehicles

Biofuels are liquid fuels that can be used in combustion engines much like those in cars and trucks of today and can replace gasoline and diesel. Currently most biofuels are typically blended with regular diesel and gasoline since engines have not been optimized to use pure biofuels, although pure biofuels are being used more extensively as an unblended direct replacement for diesel in modern engines. Some biofuels are almost identical to diesel and can be used as a direct replacement today, although they are more expensive. Biofuels are suited to large vehicles like buses and trucks but can be used in any size engine. The amount of energy stored in biofuels is more than that of hydrogen and biomethane which means that biofuels are particularly good for long distance freight vehicles.

Civic Renewable Transport Fuel Quick Start: **Accelerate the integration of renewable fuels into the City of Vancouver fleet**

The City will accelerate the transition to alternative fuels such as higher biodiesel blends, biomethane, hybrids, hydrogen, and electric. The City of Vancouver fleet has about 1,800 vehicles and equipment, with a fuel blend of 5% biodiesel and 95% regular diesel as the majority fuel used by the fleet. Moving the City fleet to renewable fuels demonstrates clear leadership, and the viability of alternative fuels and supports broader market uptake.

Biomethane Powered Commercial Vehicles

Biomethane is methane produced by natural processes, is a high-grade energy source and can be used as a direct replacement for natural gas. Methane is the major component of natural gas and biomethane is the same chemical, except made from biological processes rather than natural gas. There has been a significant effort by engine manufacturers to develop compressed natural gas (CNG) and liquefied natural gas (LNG) engines for buses and trucks, aimed at replacing diesel. These technologies are starting to become more widely available and the same technology, if fuelled using biomethane, can rapidly transform commercial freight to be renewable. Like hydrogen, biomethane is a gas, and to store enough to give a vehicle a useful range requires the biomethane to be compressed or liquefied, which has a cost premium associated with both the process and the vehicle fuel system complexity.

Hydrogen Powered Commercial Vehicles

The technology needed to power commercial freight and other large vehicles with hydrogen is almost identical to that for personal vehicles; it is simply larger and more powerful. In many ways hydrogen is more favourable for larger vehicles since the more complex fuelling systems take up less relative space and can more easily be integrated into trucks or buses.

Electric and Hybrid Commercial Vehicles

Although unlikely to be suitable for long distances, electric powertrain technologies may develop to support urban commercial use. Overhead power cables, much like those used for trolley buses could be adapted for heavy commercial vehicles – particularly those on fixed route, like to and from the port. Improved battery and charging technologies may also allow vehicles like buses to charge rapidly at their depots or at the end of their routes, while operating only on the battery along the route. Hybrid heavy-duty vehicles that use a battery to get moving or help acceleration, then switch to a combustion engine for cruising are under development and are very well suited to stop-start applications like garbage and delivery trucks.

Increase Supply of Renewable Transportation Fuels

The "hierarchy of fuels" establishes the ease with which new renewable fuels can be adopted. For mobile uses liquid fuels are preferable since they are transported easily and more easily handled during refuelling. However, with improvements in battery and charging technology, electrification is becoming an option for more vehicles, although the ease with which electric power trains can be used decreases as vehicles get larger. Cars, commercial freight and local goods and service delivery dominate motorized transportation in Vancouver. The diagram below illustrates the range of transport fuel uses and their suitability to be electrified.

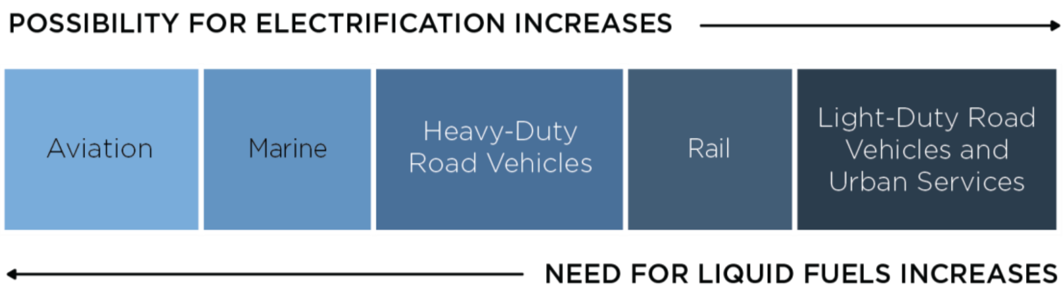


Figure 14 **– Suitability of Liquid Transportation Fuels and the Ability to Electrify Transportation**

Electricity Supply

Electricity generation in BC is legislated to be at least 93% clean and a move to 100% renewable electricity would secure its environmental benefits. Current and anticipated future electrical generating capacity in BC is able to meet the increased demand that electrification of the transport system would create; but ensuring that local electrical systems within the city are able to meet the needs of electrified transport is important. Even when that electrical capacity is supplied there will be a need to ensure that the vehicle-charging infrastructure is available for people to recharge their vehicles, particularly personal home and workplace charging.

Plug-in hybrid electric vehicles will mostly use only electricity when driving in the city, and electric vehicles will only use electricity. There is still a need to develop charging infrastructure to recharge the cars, and ensure that a network of fuelling stations exists for drivers to top up with biofuel when needed. This diversity leads to shared infrastructure needs and increased resilience so the vehicles are not tied to a single fuel source.

Biofuel Supply

Biofuels can be produced from a wide variety of feedstocks such as wood, grass, plants, and even algae, with the technologies to do so at various stages of development. There is the potential to develop significant biofuel production throughout the Pacific Northwest and central Canada. It is important to ensure that the feedstocks used to make the biofuels are grown responsibly, most preferably from what is currently considered the waste stream (*eg.* agricultural waste). The supply of biofuel feedstocks, typically canola in Western Canada, is more than sufficient to meet near-term local requirements since much of the current production is exported. The diversity of feedstocks and agricultural methods that can be used to produce biofuels limits any potential impacts to food supplies and pricing, since with the right regulation biofuel production should not compete with food production. Some relatively easy changes to the fuel supply and distribution network in the region would allow for higher amounts of renewable fuels to be blended into traditional transportation fuels, while setting the stage for a more complete long-term shift to biofuels.

Biomethane Supply

Technology such as anaerobic digestion produces biomethane from food scraps and the material left over from that process is used in the production of compost and fertilizer. Biomethane is currently in limited supply in BC since there are few sites producing it. However, as the need to replace natural gas grows there is expected to be an increase in demand. This increase in demand, and therefore production, will likely be met by landfills (which produce methane as their waste decomposes), anaerobic digesters (which take organic waste like kitchen scraps and yard trimmings to make biomethane), and waste water/sewage treatment plants. As waste diversion programs take effect and better ways to use the waste stream are implemented, biomethane production from landfills is expected to decline while anaerobic digesters will increase production volumes. The technology to distribute biomethane already exists – it is today's natural gas network.

Underway Now: **Expand the beneficial use of biomethane produced by the Vancouver Landfill**

The City will work with industry and business partners to expand the beneficial use of biomethane produced by the Vancouver Landfill beyond the current levels. The Vancouver Landfill in Delta is undergoing significant infrastructure improvements to optimize the capture of landfill gas at the site. With this optimized system in place, the opportunity exists to put more of the biomethane in the landfill gas to beneficial use by introducing it to the natural gas system or using it to fuel biomethane powered vehicles.

Hydrogen Supply

Hydrogen is in plentiful supply since it is the major constituent of water. However, the majority of hydrogen used today comes from natural gas, but using renewable electricity to electrolyze water could produce clean hydrogen in the quantities needed. A move to increase hydrogen use will require new fuelling-station infrastructure, which would be similar to the gas stations of today.

Renewably Powered Transportation Priorities

T.1 Use land-use and zoning policies to develop complete compact communities and complete streets that encourage active transportation and transit

T.1.1 Foster land use as a tool to improve transportation consistent with the direction established in Transportation 2040*.*

Transportation 2040 established three core land use directions, all of which are integral to expanding walk, bike and transit journey, while reducing personal auto vehicle journeys. The directions are:

- Prioritize and encourage a dense and diverse mix of services, amenities, jobs, and housing types in areas well-served by frequent, high-capacity transit;
- Locate major trip generators near rapid transit stations or along transit corridors; and
- Design buildings to contribute to a public realm that feels interesting and safe.

T.1.2 Enhance and accelerate the development of complete streets and green infrastructure.

Complete streets are streets that meet the needs of multiple different users from pedestrians and cyclists, to car drivers and those delivering goods. A complete street allows for improved safety for all its users, improvements in public health, and increased economic activity. Green infrastructure incorporates urban forests and vegetation into the street scape as well as better managing rainwater, and providing flood control and pollution reduction. These complementary approaches to urban design serve to reduce reliance on cars and foster more renewable transportation choices.

T.1.3 Enhance the pedestrian network according to the direction established in Transportation 2040

Transportation 2040 establishes a comprehensive approach to improving Vancouver's pedestrian network. Almost all aspects of an enhanced pedestrian network will contribute to reducing our dependence on fossil fuel derived transport, but of most note are enhancements that make it easier and more comfortable for people to walk to their destination. Attractive green spaces and green corridors promote walking and are consistent with the city's goals for its urban forest. Improving the pedestrian network will include:

- Addressing gaps in the city's pedestrian network;
- Improving accessibility and safety for people of all ability levels;
- The provision of generous, unobstructed walking environments; and
- The creation of more pedestrian-priority streets and spaces.

T.1.4 Enhance cycling infrastructure and encourage more bike trips according to the direction set in Transportation 2040

Transportation 2040 has established a clear direction upon which the city's bike network will be enhanced and expanded to increase the number of people cycling. As with improvements to the pedestrian network, all enhancements to cycling infrastructure will positively impact the transition to renewable energy. The most significant changes to encourage enhanced bike use will focus on:

- Making it easier to combine cycling with other forms of transportation.
- Upgrading and expanding the cycling network with direct, low-stress routes that are safe for people of all ages and abilities; and.
- Providing secure, convenient, accessible, and abundant bike parking throughout the city, including at home, work, shopping areas, transit stations, and other busy destinations.

T.1.5 Use parking policies to support sustainable transportation choices and efficient use of our street network.

Parking is a major transportation and land use lever, shaping the way our communities look and feel and how people get around. In accordance with Transportation 2040, the City will continue to advance parking policies to:

- Support local businesses and reduce congestion by making it easier for customers, delivery drivers, and visitors to find available spaces;
- Improve neighbourhood livability and enable other street uses by better managing on-street parking and spillover, especially where use of the street is in high demand;
- Reduce parking demand and make it easier to drive less by encouraging or requiring demand-management strategies in new development;
- Increase housing affordability and choice by separating out parking costs so people only pay for what they need; and
- Design spaces to be safe, flexible, and adaptable for a resilient city that can accommodate changing needs over time.

T.1.6 Optimize the road network to manage congestion, improve safety, and prioritize green transportation.

Vancouver's road and parking infrastructure is at capacity, with no room to expand. *Transportation 2040* sets a direction that, through optimizing the road system and managing parking as a district resource, can reduce the energy used by the vehicles in the system. The effect of the expected growth in autonomous vehicles is unclear, with both positive and negative consequences on energy and road use anticipated. To improve the network efficiency the City will:

- Ensure that the road network is optimized to manage congestion impacts;
- Consider the impacts to all road users when reallocating road space;
- Continue to support transportation demand programs that empower employers, institutions and districts to reduce driving;
- Explore technologies to better manage on-street parking;
- Where appropriate, reallocate road space to support green transportation, more vibrant public spaces, and improved safety.

***T.2 Improve transit services as set out in* Transportation 2040**

T.2.1 Extend the Millennium Line in a tunnel under Broadway

Central Broadway is the largest employment centre in the entire province after downtown Vancouver, and home to the busiest bus route in North America. Overcrowded buses pass thousands of waiting passengers each day, despite buses running every two minutes during peak periods. Many more people choose not to take transit because it is overcrowded or not convenient enough. An underground Millennium Line extension to Arbutus Street is anticipated to carry over 160,000 passengers on opening day, roughly three times as many passengers as the 99 B-Line today, and equivalent to about 24 lanes of single occupancy vehicle motor traffic. Travel times between Commercial Drive and Arbutus Street would be reduced by more than 50%, providing significantly improved access to Broadway's jobs and services for residents throughout the region.

T.2.2 Improve frequency, reliability, and capacity across the transit network

A successful transit system has a range of services. Fast, frequent, reliable, high-capacity *rapid transit* is essential to attract new riders and meet mode-share targets. Encouraging more people to shift away from the private automobile requires transit that competes favourably with driving in terms of speed, convenience, comfort, and reliability. *Local transit* is also an important part of the service spectrum, particularly for people with mobility challenges who require stops close to their destination.

T.2.3 Develop a transit supportive public realm with improved multimodal integration and comfortable waiting areas

The City will work with Translink to provide comfortable waiting areas across the transit network, and to improve connections between services and across modes. Great transit complements walking and cycling, extending the range a person can travel and connecting walking- and biking-oriented neighbourhoods together. Improved transit access supports more affordable, equitable communities by providing better access to jobs and other destinations throughout the region, and by making it easier to live car-light or car-free.

T.2.4 Work with the transit authority and other partners to transition fossil fuel powered transit vehicles to renewable energy

Much of the transit network in Vancouver already runs on renewable electricity. For the portion of the network that is not currently renewably powered the City will work with all relevant partners to transition to the use of only renewable energy sources – the focus of which will be the displacement of diesel fuel.

T.3 Transition light-duty vehicles (cars and light trucks) to be predominantly electric, plug-in hybrid or sustainable biofuel powered

T.3.1. Develop vehicle and fuel standards to support renewably powered vehicles

Advocate for a low- and zero-emission vehicle standard: The Provincial Government has the authority to establish and implement low-emission and zero-emission vehicle standards. Both standards limit tailpipe emissions from vehicles to the point where emissions are either very low or zero. Alternative fuels such as biofuels, biomethane, hydrogen, and electricity are able to meet the exacting requirement of a low-emission standard, and are the only way to directly meet zero-emission standards. By enacting this type of regulation the Provincial Government ensures that the vehicle manufacturers make cleaner vehicles, and that they are available to buy in BC.

Advocate for continued strengthening the Renewable and Low Carbon Fuel Requirements Regulation: BC already has a renewable and low carbon fuel regulation that requires the carbon intensity of fuels to be 10% lower in 2020 than they were in 2008. This regulation is imperative to moving fuel suppliers to provide low carbon and renewable fuels like biofuels, biomethane, hydrogen and electricity. Supply side regulations – regulations that affect product suppliers - like this have been shown to be more effective in reducing emissions than those policies encouraging consumers to buy clean vehicles - demand side regulation - although both are needed. The Provincial low-carbon and renewable fuel regulation should be accelerated to rapidly reduce the carbon intensity of transportation fuels and support a move to wholly renewable fuels, while letting the markets decide which fuels best meet that need.

Advocate for increased commercial vehicle efficiency and transition to renewable fuels: The Federal Government needs to set higher performance standards for heavy-duty trucks. Heavy-duty truck engine efficiencies have improved more slowly than those for personal vehicles, and there are few signs that this pace will accelerate. That needs to change. Commercial vehicle lifetimes are long, so action must be taken now to begin the transition to renewable fuels. By changing to renewable fuel options commercial operators can be protected from fuel price increases and volatility in the long run, but ways must be found to overcome the initial additional expense of renewably fuelled vehicles. The steps required to support operators to make a more renewable fuel choice include:

- The Federal Government increasing engine efficiency requirements and supporting vehicle manufacturers to warranty engines for higher biofuel blends (beyond the current industry standard 20% biofuel limit);
- The provision of Provincial and Federal purchase incentives, for both fleet and individual operators; and
- Provincial niche market regulation – a regulatory approach that mandates a small, but growing, portion of total sales to be of new technologies – of heavy-duty vehicles.

Strengthening the requirements of the low carbon and renewable fuel regulation, will have a large impact on which technologies are adopted by the commercial sector. Biofuels and biomethane are most likely to be adopted in the short-to-medium term, with hydrogen coming to market later.

Advocate for the development of financial incentives to support the growth of renewably fuelled vehicles: The Provincial and Federal Governments must provide financial incentives for the purchases of renewably fuelled vehicles. The incentive structure could be a direct purchase incentive (as BC has a limited number of at present), tax break, tax rebate or similar. The initial purchase price of renewably fuelled vehicles is still higher than that for a regular combustion engine vehicle and incentives are an effective way to support consumers to make the cleaner choice.

T.3.2 Develop supporting infrastructure that meets the needs of renewably powered vehicles

Support the expansion of renewable fuel infrastructure for personal vehicles: The diversity of renewable fuels used in the future requires new infrastructure, including enhancements to the electrical grid to supply battery electric and plug-in hybrid vehicles, as well as hydrogen fuelling stations for private and commercial vehicles. The existing natural gas and fossil fuel infrastructure can be repurposed to supply biomethane and biofuels. All these changes will require investment that must be harmonized across senior levels of government. The City is already supporting these developments where it can through *Transportation 2040*.

Enact regulation that supports the use of electricity as a transportation fuel: The Provincial Government needs to regulate electricity as a transportation fuel as well as for conventional stationary use. Electricity has not traditionally been a transportation fuel, it has been the preserve of stationary power needs. Because of this the regulation of electrical utilities and its consumers – building occupants – means that the transition to adopting electric vehicles has been hindered. Specifically, the City will urge the Provincial Government to:

- Amend the Strata Property Act to support renewably powered vehicles;
- Deregulate the sale of electricity for use as a transportation fuel;
- Introduce electrical rate tariff changes such as allowing time-of-use charging that encourages the use; and of electricity for transport and to better manage the electrical grid.

Support the expansion of renewable fuel infrastructure for commercial vehicles: As with personal vehicle fuelling infrastructure, there is a need and opportunity to increase the amount of renewable fuel infrastructure that can meet the diverse needs of the future commercial fleet. The focus of the expansion should be to:

- Explore options for increasing the use of existing alternative fueling infrastructure, particularly biofuels, biomethane and electricity; and
- Investigate options for, and the potential impacts of, developing centralized alternative fueling infrastructure in industrial areas.

Maximize the beneficial use of compostable materials: Food scraps and yard waste can form the mainstay of biomethane production. The Provincial Government has in place the BC Bioenergy Strategy, and the City wishes to see its implementation accelerated and the strategy enhanced to consider the highest and best use of food scraps. The City will review new opportunities and support the expanded use of biomethane from solid waste materials.

Use City authority over local waste management to support the use and development of renewable energy: The City will undertake a policy review to see how, under its existing authority, it can enhance the role it plays with its partners in the waste management and recovery system to support the expansion of renewable energy. The City will also continue to work with partners and other levels of government to increase the effectiveness, scope and scale of extended producer responsibility programs.

T.4 Develop car-sharing and regional mobility pricing to encourage rational journey choice

T.4.1 Support increased car-sharing and the uptake of renewably powered vehicles in car-sharing fleets.

Increasing the extent to which car-sharing services are available improves the efficiency with which roads and parking space are used, supports the emergent circular economy, has immediate environmental benefits and can help catalyze a transformation in vehicle technologies.

- Expand car-sharing services in Vancouver
- Work with car-share operators to increase the use of renewably powered vehicles in their fleets

T.4.2 Advocate for comprehensive regional mobility pricing

Pricing the transportation system to reflect the service it provides is a fundamental way to optimize performance, while encouraging sustainable choices and rational travel behaviour. Mobility pricing should:

- Support regional road or congestion pricing to encourage journey choice that accurately reflects true journey cost, better fund sustainable transport options like walking, biking and transit, and support clean vehicles where motor vehicles journey cannot be avoided; and
- Support vehicle insurance rates that reward drivers for driving less or driving a renewably powered vehicle.

T.5 Better manage commercial vehicle journeys and transition heavy-duty (commercial) vehicles to sustainable biofuels, biomethane, hydrogen and electricity

T.5.1 Improve the delivery of commercial freight, goods and services according the direction set in Transportation 2040

Support efficient goods and services movement and delivery while minimizing environmental and community impacts: *Transportation 2040* includes policies addressing a wide range of goods and services movement and delivery, for local to regional and beyond. At the local scale, the City can encourage low-impact and appropriately sized vehicles, provide for efficient deliveries and pickups, maintain an efficient truck network, and support local production and distribution to reduce the need for large-scale transport. For larger-scale movements, the City can support improved rail capacity and reliability, and Port Metro Vancouver efforts to improve environmental performance and efficiency.

Enhance local goods and service movement logistics: The goods and services transportation system will be optimized through improved logistics. This will reduce vehicle journeys, maximize vehicle utility, and minimize the extent to which loads are transferred from one vehicle to another. Efficient loading and unloading areas are an integral part of a well-functioning system in which local production and distribution reduce the need for large-scale transportation.

T.5.2 Work with fleet operators and contractors to transition to renewably powered vehicles

Engage commercial vehicle fleets to transition to renewably powered vehicles: Fleets provide an opportunity to change a large number of vehicles through shifting the thinking of just one person or business. Fleets are also very cost conscious and eager to avoid the price and volatility increases expected of gasoline and diesel. Fleet partnerships will be established to:

- Utilize local expertise to develop driver training programs for fleet managers;
- Identify technologies with the lowest uptake barriers and promote the types of fleets for which they are most effective;
- Undertake targeted outreach to educate fleet owners and managers on the potential impact and cost savings associated with renewable and smart fleet technologies; and
- Promote uptake of existing tools, such as alternative fuel apps and websites.

Partner with Port Metro Vancouver to accelerate the transition to renewably fuelled freight transport: The City will support Port Metro Vancouver in advancing port-related emissions reductions through increased energy efficiency and the expanded use of renewable energy. Port Metro Vancouver works in collaboration with industry and various government agencies and organizations to advance emissions reductions and the sustainability of the port. Vancouver will support Port Metro Vancouver in advancing emissions reduction initiatives across port operations, including, for example, increasing use of shore power (cold-ironing) for ocean-going vessels, exploring short-sea shipping opportunities, and increasing the use of clean technologies and renewable energy in trucking, rail, and cargo-handling activities. The City will also continue to support Port Metro Vancouver in advancing port sustainability and preparation for the anticipated future outlined in the Port 2050 scenario planning process, in particular the "Great Transition" scenario, which entails a rapid transition toward a low-carbon future.

Encourage movement of goods by renewably powered rail when goods must be shipped over longer distances: Rail is the most efficient method, and has the least environmental impact, when goods and people must be transported for long over-land distances. The rail system also provides the largest potential for a rapid move to renewable energy since there are only a few operators and a significant amount of infrastructure already in place that could be leveraged to speed the transition. *Transportation 2040* lays out a number of strategies to increase both freight and passenger rail service levels in Vancouver, including:

- The development and implementation of long-term rail corridor strategies; and
- Advocating for improvements to the regional rail network to address major bottlenecks.

The City will work with the Provincial Government and Metro Vancouver to require non-road engines/equipment to operate on renewable energy: The technology already exists to enable non-road engines, such as those found in construction and landscaping equipment, to operate on renewable energy. Non-road equipment powered by biofuels or electricity are starting to come to market, and through tighter regulation of greenhouse gases and air pollutants it is possible to accelerate the move towards these technologies. Regulatory approaches to increase the use and supply of electricity to construction sites will also be investigated.

A Vision of Vancouver's Renewably Powered Transportation System in 2050

Modelling the transportation demand and the ways in which it may be met through viable technological changes allows the development of a feasible vision for city's transportation energy use in 2050. Below is shown how the strategic approach of reducing demand, increasing renewable energy use and increasing renewable energy supply can meet Vancouver's transportation energy needs in 2050.

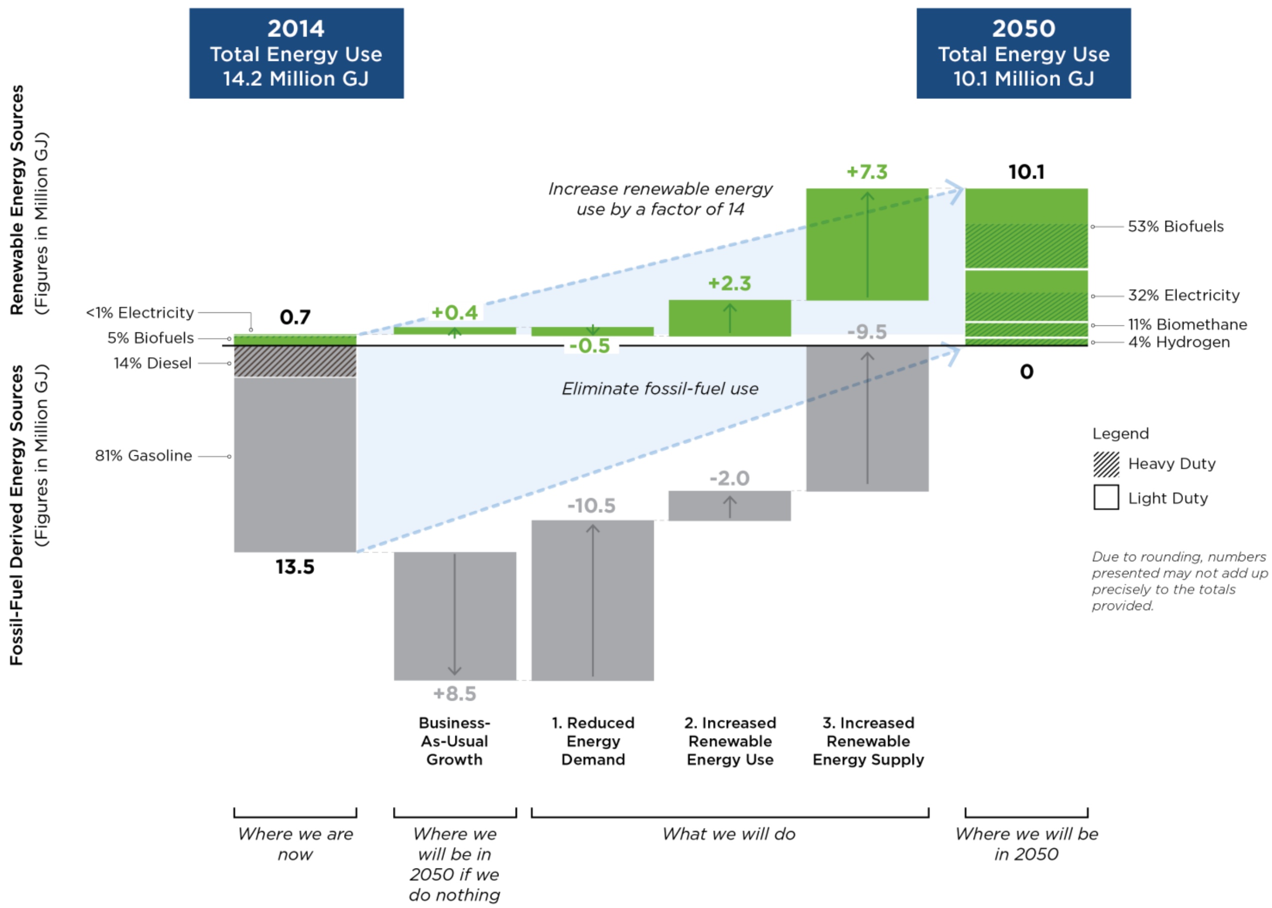


Figure 15 **– Transportation Energy Use Transformation 2014-2050**

The current passenger vehicle sector is dominated by gasoline use. With anticipated population increases the number of vehicles in the city is expected to grow by about 15%. Vehicle growth is expected to be below long-term historic growth because of improvements made to the city's walking, biking and transit infrastructure (this trend is already starting to be observed). Analysis has shown that these same measures could reduce annual vehicle kilometers travelled per car by about 20% and per person by about 40%, while at the same time reducing cars per person by about 15%. Since Vancouver is such a compact city, with short commutes, it is well suited to the use of electric vehicles and plug-in hybrid vehicles. When driving around the city the vehicles will have been charged using renewable electricity. Plug-in hybrids powered by biofuels will still allow people to make longer journeys, and use their vehicles much as they do today; but when, driving around the city will predominantly use electric propulsion. Electric vehicles and plug-in hybrid vehicles, will not suit everyone's vehicle needs, so conventional hybrid cars like today's will still be used, but be powered by biofuels. The proportion of each type of vehicle, including any conventionally fuelled vehicles that remain in 2050 will be driven by the structure of Provincial fuel and vehicle regulations and economics, as well as the extent to which home and workplace charging are developed for electric vehicles and plug-in hybrid vehicles, although by 2050 45% of vehicles could be plug-in hybrids (with biofuel combustion) and 25% fully electric with the remainder being conventional hybrids using biofuels.

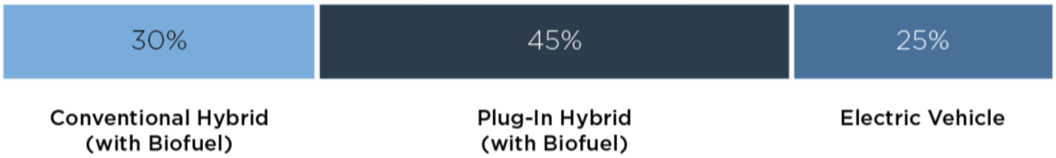


Figure 16 **– Passenger Vehicle Count by Vehicle Type 2014 and 2050**

Given Vancouver's short commutes the electrical demand required by electric vehicles and plug-in hybrid electric vehicles should not be difficult to meet; the challenge is the timing of that demand. People are likely to plug in when they get to work and then again when they get home, which also coincides with current peak demand as people prepare dinner and switch on their TV or computer, plug in their phone, and so on. There will have to be extensive load management of the electrical grid to control charging at these peak times, further demonstrating the need for the electrical grid to become "smart". There will also be a role to play for hydrogen in the personal vehicle market, although it is expected to be small.

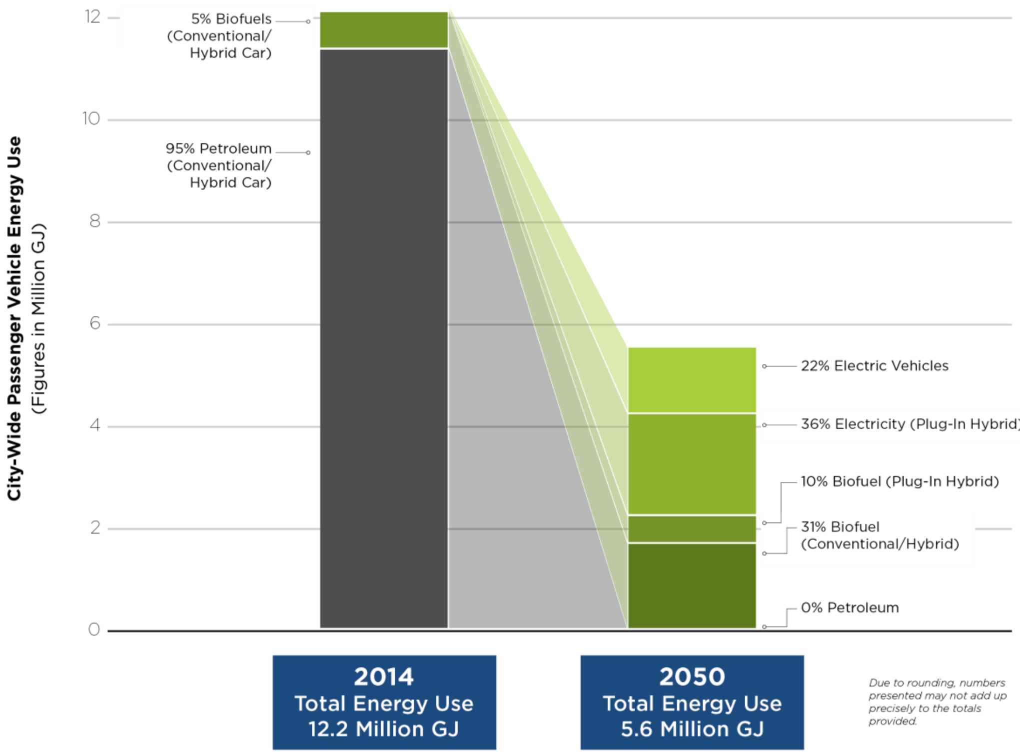


Figure 17 **– Passenger Vehicle Energy Use by Fuel Source 2014 and 2050**

The energy use by the light-to-medium commercial transport sector is driven not so much by the number of vehicles, but by the distance they travel. For heavy freight it is both the distance travelled and the weight transported by the large vehicle fleet that matters. For smaller commercial vehicles there is likely to be significant electrification with the remainder powered by biofuels or hydrogen, where the split will be determined by fuel cost economics. The use of electricity within Vancouver's transportation system will remain high because of the city's existing trolley bus system. What is less clear is the transformation to be expected in large commercial vehicles. The technology that comes to dominate will almost wholly be determined by the vehicle market's response to Provincial fuel regulations and the infrastructure that those regulations catalyze. Currently, trends in technology suggests about a one-fifth market share for hydrogen and four-fifths for biofuels and biomethane, although these proportions are very sensitive to fuel supply and purchase economics. Similarly, fuel economics are expected to significantly influence the portion of the transit system that is not electrified, but it is currently unclear whether biofuels, biomethane or hydrogen will dominate, or whether they may share equal portions. Economic growth is still expected to lead to an increase in commercial vehicle trips, which results in commercial vehicle travel staring to dominate the energy used by the transportation sector as a whole in 2050. Switching to renewable fuels will dominate changes in the commercial freight sector since, compared to personal trips, the City has less influence over how commercial trips are made. The predominance of fuel switching over trip reduction in their sector is amplified since commercial vehicles also tend to be larger and use more energy per vehicle kilometre travelled. In aggregate the trends that reduce personal transport use, but increase commercial transport need, significantly increase the importance of renewable energy for the commercial sector in overall city-wide transportation energy use.

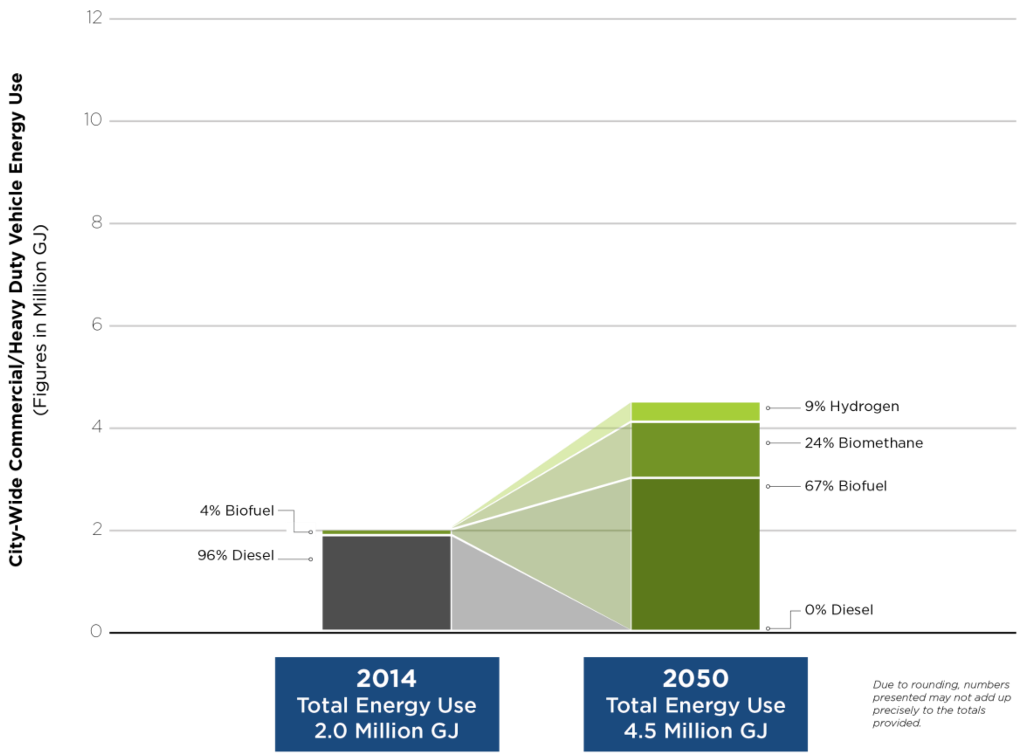


Figure 18 **– Commercial Vehicle Energy Use by Fuel Source 2014 and 2050**

TRANSPORTATION

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GLOSSARY

Renewable energy is energy that is naturally replenished as it is used

Term	Definition
Anaerobic digestion	A collection of processes by which microorganisms break down biodegradable material in the absence of oxygen. The process is used for industrial or domestic purposes to manage waste and/or to produce fuels.
Biofuel	A fuel (as wood or ethanol) composed of or produced from biological raw materials
Biomethane	A mixture of methane and carbon dioxide produced by bacterial degradation of organic matter and used as a fuel.
Cleantech	Clean Technology is a diverse range of products, services, and processes that harness renewable materials and energy sources, dramatically reduce the use of natural resources, and cut or eliminate emissions and wastes.
Climate resilience	The capacity for a city, organization or other system absorb stresses and maintain function in the face of external stresses imposed upon it by climate change and to adapt, reorganize, and evolve into more desirable configurations that improve the sustainability of the system, leaving it better prepared for future climate change impacts.
CO_2	Carbon dioxide, the primary greenhouse gas in the Earth's atmosphere.
CO_2e	Carbon dioxide equivalent: a quantity that describes, for a given mixture and amount of greenhouse gas, the amount of CO2 that would have the same global warming potential (GWP), when measured over a specified timescale (generally, 100 years). For example, methane (CH4) has a global warming potential that is 25 times greater than carbon dioxide, giving 1 tonne CH4 = 25 t CO2e.
Electric vehicle	A generic term that usually includes any vehicle that plugs into an external electrical source, including both Battery Electric Vehicles that use only electricity; and, Plug-In Hybrid Electric Vehicles, that primarily use a battery but have an on-board gasoline engine to extend range. 'EV' does not usually refer to more traditional 'hybrid' vehicles that do not obtain electric power from an external source.
Electrolysis	Chemical decomposition produced by passing an electric current through a liquid or solution containing ions
Embedded carbon/ Embedded emissions	Also known as "embodied carbon" is the amount of carbon released from material extraction, transport, manufacturing, and related activities for a given product or energy source. This may be calculated from cradle to (factory) gate, cradle to (installation) site, or (ideally) from cradle to grave.
Embedded energy	Embedded energy - also known as embodied energy - is the sum of all the energy required to produce any goods or services, considered as if that energy was incorporated or 'embodied' in the product itself. It is an accounting method that can be useful in determining the effectiveness of energy-producing or energy-saving devices, or the "real" replacement cost of a building. One fundamental purpose for measuring this quantity is to compare the amount of energy produced or saved by the product in question to the amount of energy consumed in producing it.
Feedstock	A raw material that supplies or fuels an industrial process or a machine.

Term	Definition
Fuel cell	An electrochemical cell in which the energy of a reaction between a fuel, such as liquid hydrogen, and an oxidant, such as liquid oxygen, is converted directly and continuously into electrical energy. Fuel cells are different from batteries in that they require a continuous source of fuel and oxygen or air to sustain the chemical reaction. Fuel cells can produce electricity continuously for as long as these inputs are supplied.
Fuel switch	The substitution of one fuel for another. In the context of greenhouse gas emissions, fuel switching implies the switch from a high carbon fuel to a low carbon fuel.
Gasification	Gasification is a chemical process whereby a carbon source such as coal, natural gas or biomass, is broken down into carbon monoxide (CO) and hydrogen (H_2), plus carbon dioxide (CO_2) and possibly hydrocarbon molecules such as methane (CH_4).
Geothermal/ geoexchange	Energy systems that obtain heat from the earth and/or use the ground for cooling.
Greenhouse gas	A gas that contributes to the greenhouse effect by absorbing infrared radiation, such as carbon dioxide or methane
Heat pump	A device that transfers heat from a colder area to a hotter area by using mechanical energy. Heat pumps can draw heat from air external to a building ("air source") or from geothermal energy ("ground source").
Hydrogen	A chemical element that can be burnt or used in fuel cells and which doesn't release any greenhouse gases. Hydrogen can be made from natural gas (when it is not considered renewable) or through the electrolysis of water, which if using clean electricity is renewable.
Hydrogen fuel cell vehicle	A vehicle that uses hydrogen to produce an electric current, with the only by-product being water. Often seen as an alternative to EVs, HFCVs can be fuelled similarly to traditional internal combustion engine vehicles.
Large hydro	Hydroelectric power stations that generate more than 10MW of electricity.
LED	A light-emitting diode (LED) is a semiconductor device that emits visible light when an electric current passes through it. Modern LEDs can emit a variety of colours, and have the advantage of a very long life and low power requirements.
Major roads network	Also known as arterial roads, are major through roads expected to carry the largest volumes of traffic.
Neighbourhood Renewable Energy System	Neighbourhood renewable energy systems are local energy networks that have a neighbourhood energy centre to generate heat which is piped to local buildings for space heat, hot water and, in some cases, cooling.
Passive house	The term passive house (Passivhaus in German) refers to a rigorous design philosophy that allows ultra-low energy use.
Plug load	The energy used by products that are powered by means of an ordinary outlet. This term excludes building energy that is attributed to major end uses (HVAC, lighting, water heating, etc.)
Photovoltaic	A method of converting solar energy into direct current electricity (as opposed to heat) using semiconducting material.
Renewable energy	Energy that is naturally replenished as it is used

Term	Definition
Residuals	Residuals are waste materials that remain after reusable, recyclable and compostable materials have been removed from a waste stream.
Sewer heat	Wastewater, which consists of what gets flushed down toilets but is mixed with millions of gallons of hot water from showers, dishwashers, washing machines, and more, maintains a fairly constant temperature as it travels through sewers to the treatment plant—typically about 60°F (15.6° C), though this varies by geography and season.
Small hydro	Hydroelectric plants that capture energy in flowing water, including run-of-river projects. Small hydro are considered to be projects that generate between 2MW and 10MW of power.
Solar thermal / solar heat	Heat radiation from the sun collected by heat-absorbing panels through which water iscirculated: used for domestic hot water, central heating, and heating swimming pools
Solar power	The use of the sun's energy to generate electricity through solar photovoltaic systems.
Southeast False Creek Neighbourhood Energy Utility	The Neighbourhood Energy Utility (NEU) is a self-funded facility that uses waste thermal energy captured from sewage to provide space heating and hot water to new buildings in Southeast False Creek (SEFC). This captured energy eliminates more than 60% of the global warming pollution associated with heating buildings.
Split incentive	It is often the case that a building developer is not the building owner or occupant. There is therefore little incentive for a developer to pay higher up-front costs to reduce operating costs – the incentive for a better performing building is split between the developer and the owner/occupant.
tCO_2e	Metric tonnes (equal to 1,000kg) of carbon dioxide equivalent

QUICK REFERENCE :: Priorities, Actions Underway and Quick Starts

Zero-Emissions Building Priorities

B.1 New buildings to be zero-emission by 2030

- B.1.1 Adopt and demonstrate zero-emission standards in new City of Vancouver building construction
- B.1.2 Ensure rezoning policy leads the transition to zero-emission buildings
- B.1.3 Incentivize and streamline the development of exemplary buildings
- B.1.4 Establish and enforce specific greenhouse gas intensity limits for new developments
- B.1.5 Develop innovative financing tools to help fund new zero-emission buildings
- B.1.6 Establish partnerships to build industry capacity
- B.1.7 Mandate building energy benchmarking and labelling requirements

B.2 Retrofit existing buildings to perform like new construction

- B.2.1 Use the Zero-emission New Building Strategy to reduce the need for building retrofits
- B.2.2 Mandate energy efficiency improvements for existing buildings
- B.2.3 Provide flexibility to achieve energy efficiency requirements through the support of on-site generation or neighbourhood energy system connection
- B.2.4 Facilitate modest retrofits through structured guidance and the provision of incentives
- B.2.5 Increase renewable energy use by large energy consumers

B.3 Expand existing and develop new Neighbourhood Renewable Energy Systems

- B.3.1 Expand existing Neighbourhood Renewable Energy Systems
- B.3.2 Enable the conversion of the downtown and hospital steam systems from natural gas to renewable energy
- B.3.3 Enable the development of new neighbourhood renewable energy systems for downtown and the Cambie corridor
- B.3.4 Continue to enforce, and update as required, building and renewable energy supply policies that support neighbourhood renewable energy systems

B.4 Ensure grid supplied electricity is 100% renewable

- B.4.1 Partner with utilities to increase the supply of renewable energy
- B.4.2 Partner with utilities to implement a smart grid

Zero-Emission Building Quick Starts

Civic Passive House Quick Start: The City will support a Passive House or ultra-low thermal demand design philosophy for City buildings

Retrofit Incentive Program Quick Start: The City will develop and implement a home retrofit incentive program

Civic Renewable Generation Quick Start: The City will support new renewable energy technologies for City buildings

Solar Quick Start: The City will streamline the process for the installation of rooftop solar systems

Renewably Powered Transportation Priorities

T.1 Use land-use and zoning policies to develop complete compact communities and complete streets that encourage active transportation and transit

- T.1.1 Foster land-use as a tool to improve transportation consistent with the direction established in *Transportation 2040*
- T.1.2 Enhance and accelerate the development of complete streets and green infrastructure
- T.1.3 Enhance the pedestrian network according to the direction established in *Transportation 2040*
- T.1.4 Enhance cycling infrastructure and encourage more bike trips according to the direction set in *Transportation 2040*
- T.1.5 Use parking policies to support sustainable transportation choices and efficient use of our street network
- T.1.6 Optimize the road network to manage congestion, improve safety, and prioritize green transportation

T.2 Improve transit services as set out in *Transportation 2040*

- T.2.1 Extend the Millennium Line in a tunnel under Broadway
- T.2.2 Improve frequency, reliability, and capacity across the transit network
- T.2.3 Develop a transit supportive public realm with improved multimodal integration and comfortable waiting areas
- T.2.4 Work with the transit authority and other partners to transition fossil fuel powered transit vehicles to renewable energy

T.3 Transition light-duty vehicles (cars and light trucks) to be predominantly electric, plug-in hybrid or sustainable biofuel powered

- T.3.1 Develop vehicle and fuel standards to support renewably powered vehicles
- T.3.2 Develop supporting infrastructure that meets the needs of renewably powered vehicles

T.4 Develop car-sharing and regional mobility pricing to encourage rational journey choice

- T.4.1 Support increased car-sharing and the uptake of renewably powered vehicles in car-sharing fleets.
- T.4.2 Advocate for comprehensive regional mobility pricing

T.5 Better manage commercial vehicle journeys and transition heavy-duty (commercial) vehicles to sustainable biofuels, biomethane, hydrogen and electricity

- T.5.1 Improve the delivery of commercial freight, goods, and services according the direction set in *Transportation 2040*
- T.5.2 Work with fleet operators and contractors to transition to renewably powered vehicles

Transportation Quick Starts and Actions Underway

Preferential Parking Quick Start: Support the uptake of renewably powered vehicles through preferential parking provision

Civic Renewable Transport Fuel Quick Start: Accelerate the integration of renewable fuels into the City of Vancouver fleet

Underway Now: Replace the Georgia and Dunsmuir viaducts for better at grade services and public space

Underway Now: Implement a public bike-share system

Underway Now: Improve the False Creek bridges to support active transport

Underway Now: Develop and implement an electric vehicle infrastructure strategy to accelerate electric vehicle uptake

Underway Now: Expand the beneficial use of biomethane produced by the Vancouver Landfill

City Services Renewable Energy Priorities

S.1 The City will adopt a comprehensive approach to the consideration of climate change as part of its service planning

S.2 The City will adopt a comprehensive approach to pricing carbon emissions for municipal operations

S.3 The City will develop a framework to assess how City enabling tools may be used to support the transition to 100% renewable energy

S.4 The City commits to keep abreast of financing mechanisms available that enable the delivery of renewable energy technology and other green infrastructure

City Service Quick Starts

Licensing Powers Quick Start: The City of Vancouver will investigate how best to use its licensing and permitting powers to accelerate the adoption of renewable energy

Purchasing Power Quick Start: The City of Vancouver will investigate how best to use its purchasing power to accelerate the adoption of renewable energy

Economic Opportunity Priorities

E.1 Support innovators through business and technology research, incubation, acceleration, and demonstration.

E.2 Actively work with businesses to increase the use of renewable energy

E.3 Target key events and organizations that represent cleantech and renewable energy to strengthen Vancouver's economy

E.4 Attract 'green capital' and enable more innovative financing mechanisms for clean and renewable businesses

Economic Opportunity Quick Starts

Underway Now: Expand and accelerate the Green and Digital Demonstration Program

Business Emissions Quick Start: Use the Vancouver Business Energy and Emissions Profile to develop a targeted business energy use reduction and fuel switching strategy