Diane Roy
Director, Regulatory Services

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

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

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

December 18, 2015

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary and Director

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI or the Company)

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

Response to the British Columbia Utilities Commission (BCUC or the Commission) 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 BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

Table of Contents

A. FORTISBC ENERGY INC. EVIDENCE

1.0 Reference: Exhibit B-1, Application, Section 1.2, pp. 2, 3

Amalgamation

A notable change since the release of the British Columbia Utilities Commission (Commission) Generic Cost of Capital (GCOC) Stage 1 Decision[1] is the amalgamation of FEI with FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW). On page 3 of its Application, FEI states that as was the case in 2012, FEI's core market is experiencing declining use per customer and low customer growth while facing the same competitive challenges as FEI did pre-amalgamation.

1.1 For purposes of comparability and presentation, please provide FEI's business profile for the years 2004 to 2014 (historical) and 2015 (projected), with FEVI and FEW included showing:

1.1.1 Rate base.

Response:

The following table provides responses to BCUC IRs 1.1.1.1 through 1.1.1.7.

	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Approved
Rate Base ($million) 1	$ 2,764	$ 2,878	$ 2,924	$ 2,921	$ 3,000	$ 3,025	$ 3,118	$ 3,275	$ 3,513	$ 3,573	$ 3,588	$ 3,661
Sales/Transport Volumes (TJ) 5	174,182	172,962	172,001	172,856	169,318	167,107	169,343	173,402	177,948	170,675	170,638	176,035
Average Number of Customers 2												
Residential	773,214	787,745	801,473	817,675	829,745	839,119	847,803	855,942	850,516	857,115	868,333	878,512
Commercial	85,898	86,952	87,729	89,284	90,276	91,291	91,667	92,063	87,610	87,974	89,738	90,825
Industrial	1,235	1,213	1,210	1,141	1,097	1,078	1,037	1,000	983	997	1,020	1,052
Residential %	90%	90%	90%	90%	90%	90%	90%	90%	91%	91%	91%	91%
Commercial %	10%	10%	10%	10%	10%	10%	10%	10%	9%	9%	9%	9%
Industrial %	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Net Customer Additions 2												
Residential	15,742	13,860	12,744	15,794	11,321	7,723	9,186	6,911	6,371	9,139	10,472	9,708
Commercial	(66)	1,867	937	1,224	1,504	457	223	525	442	1,371	1,197	1,004
Industrial	(35)	(45)	76	(128)	(52)	(31)	(94)	(58)	(6)	(22)	2	-
Customer Growth Rate 2, 3												
Residential	2%	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%
Commercial	0%	2%	1%	1%	2%	1%	0%	1%	0%	2%	1%	1%
Industrial	-3%	-4%	6%	-10%	-4%	-3%	-9%	-6%	-1%	-2%	0%	0%
Customer Profile by Demand 4, 5												
Residential (TJ)	76,600	74,721	74,774	75,411	73,727	74,829	74,964	73,885	74,468	72,690	73,190	73,068
Commercial (TJ)	50,072	48,962	49,846	51,496	51,799	53,129	52,474	53,995	54,651	53,586	54,033	55,573
Industrial (TJ)	47,510	49,278	47,381	45,948	43,792	39,149	41,905	45,522	48,830	44,399	43,416	47,394
Residential %	44%	43%	43%	44%	44%	45%	44%	43%	42%	43%	43%	42%
Commercial %	29%	28%	29%	30%	31%	32%	31%	31%	31%	31%	32%	32%
Industrial %	27%	29%	28%	26%	25%	23%	25%	26%	27%	26%	25%	26%
Customer Profile by Revenue 4, 5												
Residential ($000)	873,774	931,694	1,003,386	955,439	983,682	901,294	883,928	815,442	752,348	739,068	799,029	814,408
Commercial ($000)	478,590	511,941	548,102	546,311	567,737	522,038	498,682	470,026	440,921	425,950	456,021	454,626
Industrial ($000)	106,729	112,132	111,358	93,352	102,491	94,912	92,723	93,686	100,741	96,668	99,099	94,386
Residential %	60%	60%	60%	60%	59%	59%	60%	59%	58%	59%	59%	60%
Commercial %	33%	33%	33%	34%	34%	34%	34%	34%	34%	34%	34%	33%
Industrial %	7%	7%	7%	6%	7%	7%	6%	7%	8%	7%	7%	7%

[1] British Columbia Utilities Commission Generic Cost of Capital Stage 1 (GCOC Stage 1), Decision dated May 10, 2013, Order G-75-13.

Notes:

1. Sum of each of FEI, FEVI and FEW Utility's rate base without intercompany eliminations.
2. Allocations into Commercial and Industrial groups for FEVI and FEW are based on the **Customer** allocation percentages in Tables 4-6 and 4-7 from FEI's Common Delivery Rates Methodology Application.
3. Customer Growth % = Customer Additions divided by Previous Year End Customers.
4. Allocations into Commercial and Industrial groups for FEVI and FEW are based on the **Volume** allocation percentages in Tables 4-6 and 4-7 from FEI's Common Delivery Rates Methodology Application.
5. Normalized, non-bypass customers only.

1.1.2 Sales/transportation volumes.

Response:

Please refer to the response to BCUC IR 1.1.1.1.

1.1.3 Average number of customers (residential, commercial, industrial).

Response:

Please refer to the response to BCUC IR 1.1.1.1.

1.1.4 Net customer additions (by type).

Response:

Please refer to the response to BCUC IR 1.1.1.1.

1.1.5 Customer growth rate (by type).

Response:

Please refer to the response to BCUC IR 1.1.1.1.

1.1.6 Customer profile by demand (TJ, percentage share).

Response:

Please refer to the response to BCUC IR 1.1.1.1.

1.1.7 Customer profile by sales revenue (value, percentage share).

Response:

Please refer to the response to BCUC IR 1.1.1.1.

2.0 Reference: Exhibit B-1, pp. 5–6, 34

Benchmark utility

On pages 5 and 6 of its Application, FEI states:

> [The] GCOC Stage 2 Decision stated that the amalgamated FEI shall remain the benchmark utility. FEI believes that Amalgamated FEI continues to be the logical choice to serve as the benchmark utility. FEI Amalco is engaged in the same businesses as pre-amalgamation FEI. The Commission should consider the business and risk profile of the amalgamated FEI and continue to treat FEI as the benchmark utility.
>
> It should be noted that a determination in this regard does not impact the determination of FEI's cost of capital. The benchmark is used in setting the ROE for other utilities in their own cost of capital determinations.

In the GCOC Stage 2 Decision[2], the Commission stated:

> Once amalgamation has been effected and postage stamp rates implemented, the ROE and capital structure will be the same for the amalgamated entity as for FEI as the Benchmark utility. In the alternative, if FBCU considers the cost of capital for the amalgamated entity is not indicative of current circumstances, it may apply to the commission on behalf of the amalgamated entity.

2.1 To what extent does FEI consider that the current cost of capital for FEI the amalgamated entity (Amalgamated FEI, FEI Amalco) is not indicative of current circumstances? That is, if FEI did not amalgamate, would the request for equity thickness and return on equity (ROE) be identical to the requests (9.5 percent ROE and 40 percent equity thickness) made in this application?

<u>Response:</u>

Yes. FEI would have requested the same ROE and capital structure, even if it did not amalgamate.

The proposed 9.5 percent ROE is based on Mr. Coyne's quantitative analysis of investors' expected return for a similar-risk proxy group of companies (both CAPM and DCF models with alternative inputs and specifications were used to calculate a range for ROE estimation) in conjunction with qualitative analysis of FEI's risk in comparison with other natural gas utilities in U.S. and Canadian proxy companies. Investors' expected return has not been affected by

---

[2] British Columbia Utilities Commission Generic Cost of Capital Stage 2 (GCOC Stage 2), Decision dated March 25, 2014, Order G-47-14, p. 138.

amalgamation. Please refer to Mr. Coyne's response to BCUC IR 1.33.1 and FEI's response to BCUC IR 1.13.2 for more information.

As explained on page 3 of FEI's Application, amalgamation is not the primary justification for FEI's request to increase its equity thickness; FEI Amalco remains a large natural gas distribution utility, regulated by the BCUC, whose core business is to provide space and water heating to its customers. The main rationale for FEI's request to increase its equity thickness relates to the upward trend in business risk, in particular the increase in the political risk category, and its relatively weak financial metrics. As stated on page 96 of Mr. Coyne's testimony, as the FEVI and FEW rate bases are amalgamated into FEI at the lower equity ratio and allowed return as of January 1, 2015, all else being equal, the amalgamation is expected to somewhat reduce FEI's credit metrics.

2.2 FEI states that the Commission should continue to treat Amalgamated FEI as the benchmark utility. FEI further states that a determination in this regard does not impact the determination of FEI's cost of capital. Does FEI agree that how the Commission assesses the cause(s) to FEI Amalco's risks in the current proceeding will impact the relative risks of other entities in BC that rely on the pre-amalgamation FEI benchmark utility?

Response:

FEI would characterize its position slightly differently. FEI's position is that the amalgamation does not, in and of itself, affect FEI's *continued ability* to serve as the benchmark utility, rather than the Commission setting a "new benchmark". The nuance is important in the context of this question. It has always been the case that the risks facing the benchmark utility change over time. The crux of the question posed is whether or not the amalgamation has had such a significant impact (increase) on FEI's business risk since 2012 that it alone would necessitate the Commission revisiting the risk faced by other BC utilities relative to FEI following the decision in this Application.

FEI's view is that amalgamation does not necessitate review of other utilities' risk premiums. FEI's view (reflected on p.3 of the Application, starting at line 12) is that: "While amalgamation is a factor affecting FEI's business risk that should be considered, it is not the primary justification for FEI's request to increase FEI's equity thickness or ROE." While amalgamation has increased the size of FEI, it has not fundamentally changed the risk profile as FEI continues as a natural gas distribution company, within the same geographic, legal and regulatory jurisdiction. The increased size in this instance does not provide any diversification benefit; while the nature of the assets amalgamated, as noted, has unique aspects that contribute to a marginal increase in supply risk. Please refer to the response to BCUC IR 1.13.2 for more information.

2.2.1 Assuming the Commission finds that the risks of FEI Amalco are different from pre-amalgamated FEI <u>due in whole or in part</u> to amalgamation, does making FEI Amalco as the new benchmark require a total reconsideration of the relative risks between the new benchmark and the other regulated utilities?

<u>Response:</u>

No. Even if the Commission finds the risks are different, the determination of whether the relative risks of the other utilities compared to the benchmark utility needs a total reassessment by the Commission should account for whether the change is sufficiently material to justify the cost of additional regulatory proceedings. This is especially true given how recently the Commission examined other utilities' risk premia and capital structures in the Stage 2 proceeding. While amalgamation may have had some impact on risk, as noted in BCUC IR 1.2.2, the change is modest. FEI does not believe that amalgamation, in and of itself, would justify an examination so soon after the Stage 2 decision.

3.0 Reference: Exhibit B-1, Section 3.2, p. 10

The three requirements of the Fair Return Standard

On page 10, FEI states that the Fair Return Standard is only satisfied if the utility can attract capital on reasonable terms and conditions, its financial integrity can be maintained and the return allowed is comparable to the returns of enterprises of similar risk.

3.1 Please provide the latest forecast of the expected rate of return on the defined benefit pension plan assets of the FortisBC subsidiaries and the actuarial firm that provided the forecasts. These forecasts should include the overall expected rate of return and the rates of return on the following asset groups where appropriate: (a) Canadian equities; (b) US equities; (c) Non-North American equities; (d) bonds; and (e) cash.

<u>Response:</u>

The requested information has been provided by the Company's actuarial consulting firm, Towers Watson, and is shown below. The various pension asset returns forecasted by actuarial firms and used in the build-up of the Company's expected rate of return on assets (EROA), used solely for determining the pension accounting expense and obligation, are not appropriate or relevant in the determination of FEI's own ROE as explained further in the response to BCUC IR 1.3.2.

Since the FortisBC subsidiaries establish an overall EROA on the defined benefit pension plan assets for accounting purposes as at December 31 of each year, the most recent forecasted EROA of 6.50% is as at December 31, 2014. Note that this is a geometric return, which is not comparable to the arithmetic return used in the context of determining FEI's allowed ROE. While the individual forecasted geometric returns by asset class provided by Towers Watson are used as underlying assumptions in determining the FortisBC subsidiaries' EROA, the EROA is selected at a higher level. This approach considers that this pension accounting assumption is subject to review and change each year and the various FortisBC defined benefit pension plans will change their targeted asset mixes over time.

Canadian equities	7.00%
US equities	7.40%
Non-North American equities	7.40%
bonds	3.45%
Real estate	6.50%

While the question requests forecasted return on cash, none has been provided as this is not a significant targeted asset class within the various pension plans.

3.2 Please comment on these pension plan investors' expected rates of return on equities, in particular Canadian equities, with the ROE that FEI is requesting in this application.

Response:

The pension plan investors' expected rates of return on equities provided in the response to BCUC IR 1.3.1 are not relevant in the assessment of FEI's requested ROE. In the GCOC Decision, the Commission determined that actuarial expectations were not conservatively biased and were used to fairly assess pension plan liabilities. FEI agrees with the Panel's decision that these expected returns are appropriate for pension plan liabilities. However, the various long-run pension asset returns forecasted by actuarial firms, used solely by the Company for estimating pension expense and obligation for accounting purposes, are not appropriate or relevant in the determination of FEI's own ROE for several reasons.

First, even before turning to the conceptual difficulties associate with considering pension fund return assumptions provided by the actuarial firms in the establishment of a utility's cost of equity, it is necessary to recognize that these equity return forecasts are using a geometric return. Geometric returns are more relevant in the measurement of pension plan asset performance over a period of time, while the use of arithmetic returns is more appropriate for estimating a utility's cost of capital[3]. As an example, if the forecasted 7.0% geometric return on Canadian equities provided by the actuary, shown in the response to BCUC IR 1.3.1, were shown on the arithmetic basis, the equivalent return expectation would approximate 9.0%. However, even with the translation of the Canadian equities long-run geometric return to an arithmetic return, the suggestion that these pension returns should be used for establishing an allowed ROE remains flawed, as discussed further.

Second, the expected long-term equity returns derived by actuarial firms are comprised of a diversified asset portfolio for which forecast returns are not comparable in risk to a single, specific utility. These forecasted equity returns are based on a portfolio of different companies and different industries that have varying risks. Pension plans will invest in a similar portfolio of equity investments as the exposure to specific company risk is minimized and replaced with exposure to more systemic market risk. Conversely, FEI continues to be subject to specific company risk which cannot be eliminated on a stand-alone basis. Accordingly, it is reasonable that the return for investing in a single utility will be higher than the asset return forecasted by actuarial firms on a portfolio of equity investments.

---

[3] The appropriateness of using arithmetic versus geometric means in estimating utilities' cost of capital is discussed in Morin, *New Regulatory Finance*, p. 133 et. *seq.*

Third, expected long-term equity returns derived by actuarial firms will assist in meeting the objectives of a pension fund which differ from investors' expectation of a fair return in a single utility. Pension plan investment governance focuses on investing in a portfolio of investments with the objective of ensuring that there are sufficient assets available to fund employee retirement income. This objective differs from utility regulation which seeks to obtain a fair return.

In summary, the forecasted returns on pension fund assets provided by actuarial firms are not relevant in determining a fair ROE for FEI.

4.0 Reference: Exhibit B-1, Section 4, pp. 11–14; Appendix C – Business Risk Assessment, Table C-2

Definition of risks

In Section 4, FEI provides a high level summary of factors affecting FEI's risk profile. FEI adopted the same eight business risk categories that it had employed in the GCOC proceeding.

4.1 In the GCOC Stage 1 Decision[4], the Commission referred to business risk in terms of short-term and long-term risks. Is it the position of FEI that the business risks as summarized in Section 4 of the Application and elaborated in Appendix C are all long-term risks?

<u>Response:</u>

Business risk can be categorized in different forms. For the sake of consistency and continuity of risk assessment, FEI adopted the same eight business risk categories that it had employed in the GCOC proceeding. As noted on page 11, footnote 10 of FEI's Application, certain factors within FEI's business risk categories impact investors' short-term expectations (i.e. they can be categorized as short-term risk) while others are long-term risk factors. Short-term risk relates to a company's ability to earn a fair return on invested capital and manage year-to-year variability in earnings while long-term risk is comprised of factors that may negatively impact the long-term viability of the utility and impair the ability of shareholders to fully recover their invested capital.

Generally speaking, items such as political risk factors (energy policy and legislation, local government policies and initiatives, carbon tax and Aboriginal rights and title issues), market shift risk factors (new technology and energy forms, perception of energy, housing mix, changes in use per customer and capture rates), competitive position of natural gas relative to electricity, availability of supply, business profile risk factors as well as certain aspects of regulatory uncertainty risk manifest long-term risk characteristics. Risk factors such as those related to deferral accounting or short-term economic conditions are more aligned with the short-term risk category. FEI believes that the major changes in FEI's business risk in comparison to the GCOC Stage 1 proceeding are related to long-term risk, particularly long-term political risks.

Short-term and long-term risks are also discussed in Mr.Coyne's direct testimony[5]. Mr.Coyne defines short-term risks as those that will reverse or resolve themselves within a year or two, either through regulatory relief or normal ebb and flow of earnings (such as storms, supply constraints or financial market disruptions) and long-term risks as those that relate to a shift in the business profile of the company for which there is no foreseeable mitigation (such as stranded assets due to loss of market share or environmental policies that substantially impact a

[4] GCOC Stage 1, Decision dated May 10, 2013, p. 24.
[5] Appendix B, p. 61.

company's operations). Furthermore, Mr. Coyne's risk comparison analysis (Appendix B, Table 15) distinguishes between major short-term risk factors (revenue stabilization and cost recovery) and long-term risk factors (operating risk, supply and infrastructure risk, price and volatility risk, volume demand risk, political and regulatory risks) and concludes that FEI has higher long-term risks than the U.S. proxy group on a number of these factors.

Table C-2 within Appendix C shows the amalgamated FEI's business risk as compared to the 2012 benchmark utility.

4.2 FEI proposes a capital structure of 40 percent equity and 60 percent debt, and an ROE of 9.5 percent, which is an additional 1.5 percent to the equity thickness and 75 basis points (bps) to the ROE. To the extent possible, please breakdown the incremental proposed equity thickness and ROE into the following contributing factors: (i) risk associated with continued volatility and uncertainty in the financial markets since 2012; (ii) amalgamation on December 31, 2014; and (iii) other contributing factors – please specify.

Response:

As explained on page 11, line 16 of FEI's Application, and consistent with the Company's position in previous cost of capital proceedings, FEI believes that the assessment of business risk is an inherently qualitative exercise and that investors appraise business risk on an overall aggregate basis, not by relying on a risk by risk check list. The business risk assessment must be used in conjunction with other quantitative and qualitative factors to facilitate judgment on the overall risk of a utility compared to its peers and ultimately what constitutes a reasonable ROE and capital structure for the utility.

The proposed 9.5 percent ROE is based on Mr.Coyne's quantitative analysis of investors' expected return for a similar-risk proxy group of companies (both CAPM and DCF models with alternative inputs and specifications were used to calculate a range for ROE estimation) in conjunction with qualitative analysis of FEI's risk in comparison to those companies.

The main rationale for FEI's request to increase its equity thickness relates to the upward trend in business risk led by the increase in the political risk category and its weak financial metrics. As explained on page 3 of FEI's Application, while amalgamation is a factor affecting FEI's business risk, it is not the primary justification for FEI's request to increase its equity thickness and ROE. Furthermore, as stated on page 16 of FEI's Application, the capital market conditions can be considered broadly similar to 2012 levels.

4.3 In its risk assessment, FEI uses the terms "lower", "same", and "higher" from an original point to a current point in time. There are instances where FEI states that a particular risk is "being similar to that of the 2012 benchmark utility and trending higher."[6] Please clarify what is meant by "trending higher."

Response:

As stated, FEI's overall business risk factors are similar to the risk factors presented in the 2012 GCOC proceeding; however, FEI anticipates experiencing a steeper upward trend in certain risk categories in the near future that are not yet fully realized.

For instance, although political risk in this Application is assessed to be higher than the 2012 level due to the recent developments in local governments' policies in promoting mandatory connections, the political risk category may face a significant incremental (i.e., steeper) upward trend from developments that are not yet fully realized. The BC provincial government's environmental and climate change policies are similar to the ones that existed during the GCOC proceeding; however, as mentioned on page 64 of Appendix C – FEI Business Risk, the BC government is in the midst of developing a new "climate leadership plan" to review the options available for reinforcing the provincial efforts to reduce GHG emissions and has created a "Climate Leadership Team" to provide advice and recommendations to government on a new Climate Action Plan. This team has recently published a series of recommendations to the government that, if accepted, can significantly affect FEI's competitiveness, UPC, throughput, capture rate and in general the long-term viability of its traditional markets. Some of these recommendations are as follows:

- To establish a legislated 2030 target of 40 percent GHG emissions reduction below 2007 levels;
- Establish sectorial GHG reduction goals (below 2015) for 2030 including 50 percent for built environment and 30 percent for industrial sector with special focus on the natural gas industry;
- A fiscal policy to increase the carbon tax by $10/year commencing in July 2018 and expand the coverage of the current carbon tax to apply to all GHG sources in BC after 5 years;
- To use the other incremental revenues generated from the increase in the carbon tax to eliminate PST on all electricity rates; and

[6] Exhibit B-1, p. 14.

- Amend the Environmental Assessment Act to include the social cost of carbon in the environmental assessment process.

It is not clear if the BC government will adopt these recommendations or not; however, it has previously stated that as other jurisdictions introduce similar policies such as carbon taxes or carbon pricing, it may consider changes to its policies. With the introduction of a carbon tax in Alberta and the cap and trade mechanism in Ontario, it is likely that the government will give serious consideration to the recommendations provided by the Climate Leadership Team.

Municipal policies are also evolving quickly, as evidenced by the recent strategy issued by the City of Vancouver that was published after the filing of this Application. Please refer to the response to CEC IR 1.44.1 for further information in that regard.

5.0 Reference: Exhibit B-1, Table 2, p. 20; Table 4, p. 26

The approach of rating agencies

FEI's Application on page 20 provides as Table 2, Moody's Investors Service (Moody's) rating grid for regulated utilities, which indicates that 25 percent of the weighting is placed on the regulatory framework, 25 percent on ability to recover costs and earn returns, 10 percent on diversification and the remaining 40 percent on financial strength as measured by credit metrics.

5.1 Please explain if FEI considers that the regulatory framework and the ability to recover costs are relatively similar for gas distribution and electricity distribution utilities across Canada and particularly for the regulated distribution utilities that FEI has included in its Table 4 on page 26 of its Application.

<u>Response:</u>

FEI agrees there are relative similarities among the regulatory jurisdictions in Canada in the sense that, for instance, the Fair Return Standard applies, the regulators all set rates based on variants of cost of service principles or performance based regulation of some kind, and there is a requirement to allow utilities to recover prudently incurred costs. FEI has retained Mr. Coyne to provide further insight into the differences and similarities of how regulators approach and adhere to these principles in various jurisdictions, as part of his expert testimony in the proceeding. As Mr. Coyne discusses on page 10 of Appendix B, the BCUC embraces the same legal standards for the application of the Fair Return Standard as those put forth by the NEB, the OEB and those established through Canadian and U.S. common law. Further, as explained on page 87 of Mr. Coyne's evidence, Canadian utilities are governed by comparable regulatory models.

The preamble refers to Moody's. Several of these utilities engage Moody's to provide credit opinions, thus allowing Moody's the opportunity to obtain more specific knowledge and insight into their respective regulatory frameworks and ability to recover costs. FEI believes, based on how Moody's has assigned different rating scores to the sub-factors relating to the regulatory framework and the ability to recover costs for various utilities, it can reasonably be concluded that Moody's regards that the regulatory framework and the ability to recover costs may change from utility to utility depending on the circumstances specific to each utility.

5.1.1 Please confirm that under Moody's rating grid, if the regulatory framework and ability to recover costs were very similar between two or more regulated utilities and if diversification were not a factor due to the utilities being standalone with monopoly territories, then the differentiating factor in the credit rating between such utilities would appear to depend largely upon differences in financial strength as indicated by the four credit metrics listed in Table 2.

Response:

All else being equal, differences in financial strength as measured through credit metrics could be the differentiating factor in the rating of two companies. However, as stated on page 20 of FEI's Application, the factors in the rating grid do not constitute all of the considerations for ratings of companies in the regulated electric and gas utility sector. Moody's methodology considers other factors outside of the grid in its ratings including assessment of management and corporate governance, financial controls, liquidity and access to capital markets, seasonality, event risk and acquisition strategy.

6.0 Reference: Exhibit B-1, Figure 1, p. 21; Figure 2, p. 22

Credit spread between BBB-rated and A-rated corporate issuers

On page 21, Figure 1 shows the indicative 30 year credit spreads of BBB-rated and A-rated new issuances from January 2005 to August 31, 2015. FEI indicates that the average credit spread is approximately 70 basis points (bps) from January 2005 to August 2015.

On page 22, Figure 2 shows the indicative 30 year credit spread between selected BBB/split rating and A-rated utilities.

6.1 Please provide the corresponding data by quarter in Figure 1 on page 21.

Response:

Please refer to the table below for the corresponding data by quarter relating to Figure 1. This information represents the average credit spreads for the quarter as provided by RBC Capital Markets.

Date	BBB-rating	A-rating	BBB-A Delta
Q1 - 2005	149	117	32
Q2 - 2005	165	126	38
Q3 - 2005	155	122	33
Q4 - 2005	160	130	30
Q1 - 2006	165	134	31
Q2 - 2006	163	134	29
Q3 - 2006	168	138	30
Q4 - 2006	173	135	38
Q1 - 2007	173	130	44
Q2 - 2007	197	145	52
Q3 - 2007	240	172	68
Q4 - 2007	262	185	77
Q1 - 2008	340	233	107
Q2 - 2008	369	241	128
Q3 - 2008	378	261	117
Q4 - 2008	551	434	117
Q1 - 2009	565	470	95
Q2 - 2009	453	357	96
Q3 - 2009	326	241	85
Q4 - 2009	287	206	81
Q1 - 2010	244	183	60
Q2 - 2010	254	195	59
Q3 - 2010	259	197	62
Q4 - 2010	254	194	60
Q1 - 2011	250	182	68
Q2 - 2011	260	185	75
Q3 - 2011	283	204	79
Q4 - 2011	318	224	94
Q1 - 2012	316	203	113
Q2 - 2012	316	199	117
Q3 - 2012	315	200	114
Q4 - 2012	298	196	102
Q1 - 2013	292	187	105
Q2 - 2013	268	179	89
Q3 - 2013	268	185	84
Q4 - 2013	257	185	72
Q1 - 2014	238	174	64
Q2 - 2014	227	169	58
Q3 - 2014	225	171	53
Q4 - 2014	238	181	57
Q1 - 2015	250	194	56
Q2 - 2015	248	195	53
Q3 - 2015	270	221	49

6.1.1 Please compare the following time horizon in Figure 1: (i) 2009-2012; and (ii) 2012-2015. Is there a widening or narrowing of credit spreads?

Response:

The graphs included in Figure 1 of the Application, and referred to in the preamble, consist of the credit spread differentials between BBB and A rated companies and point to the fact that a large delta exists between the credit spreads of these two groups. The credit spreads have been accumulated per the requested time periods as per the table below.

	BBB-rating		A-rating		BBB-A Delta	
	2009-2012	2012-2015	2009-2012	2012-2015	2009-2012	2012-2015
Average	+312	+268	+227	+189	+85	+79
Max	+565	+316	+470	+221	+117	+117
Min	+244	+225	+182	+169	+59	+49

As shown in the table above, the average BBB-A new issuance spread differential has only decreased by 6 bps (85 bps as compared to 79 bps) during the two noted time horizons, which is within the expected level of monthly variance. However, the differential between BBB and A rated issuances has historically seen more significant fluctuations, particularly during periods of market disruption. The widening of these differentials greater than 100 bps can be seen as recently as 2012 and 2013. This differential is expected to continue to fluctuate going forward, and should FEI be downgraded to a BBB or split rating, it would be exposed to these larger fluctuations in credit spreads.

Credit spreads were wider during the early part of 2009 as the economy was still recovering from the financial crisis. Subsequent to 2009, spreads remained relatively low as they dipped below 300 bps for BBB rated issuances and below 200 bps for A rated issuances. From late 2011 to the end of 2012, the credit spreads for BBB-rated issuances increased back to above 300 bps. From 2013 onwards, credit spreads generally narrowed again remaining below 200 bps for the A rated category for most of this time. However, as recently as Q3 2015, these spreads have again begun to increase to greater than 220 bps for A rated companies, which was the highest quarterly average spread seen between 2012-2015.

6.2 Please calculate the average credit spread and the corresponding data by quarter in Figure 2 on page 22.

Response:

The average credit spread differential between the selected BBB/split rating and A-rated utilities for the period is 16 bps. Please refer to the table below for the corresponding data by quarter relating to Figure 2.

	BBB/Split Rated Average	A Rated Average	BBB vs. A Rated Spread
Q1 - 2008	+172	+149	+23
Q2 - 2008	+177	+162	+15
Q3 - 2008	+211	+193	+18
Q4 - 2008	+338	+312	+26
Q1 - 2009	+356	+323	+33
Q2 - 2009	+256	+220	+36
Q3 - 2009	+179	+160	+19
Q4 - 2009	+168	+151	+17
Q1 - 2010	+152	+139	+13
Q2 - 2010	+158	+147	+11
Q3 - 2010	+158	+142	+16
Q4 - 2010	+151	+137	+14
Q1 - 2011	+144	+135	+9
Q2 - 2011	+149	+139	+10
Q3 - 2011	+164	+151	+13
Q4 - 2011	+177	+162	+15
Q1 - 2012	+159	+143	+16
Q2 - 2012	+168	+156	+13
Q3 - 2012	+168	+155	+13
Q4 - 2012	+168	+152	+15
Q1 - 2013	+157	+144	+12
Q2 - 2013	+154	+144	+10
Q3 - 2013	+164	+151	+13
Q4 - 2013	+161	+146	+15
Q1 - 2014	+147	+135	+12
Q2 - 2014	+147	+136	+11
Q3 - 2014	+151	+141	+10
Q4 - 2014	+162	+147	+15
Q1 - 2015	+169	+149	+20
Q2 - 2015	+168	+147	+21
Q3 - 2015[1]	+202	+177	+25

1 - Q3 2015 data includes spreads up to August 24, 2015.

6.2.1 Please compare the following time horizon in Figure 2: (i) 2009-2012; and (ii) 2012-2015. Is there a widening or narrowing of credit spreads?

Response:

For clarity, Figure 2 from page 22 of the Application shows the differential between the indicative 30 year credit spread of selected BBB/split rated and A-rated utilities, but not the utility credit spreads themselves. This information shows how credit spreads within these two utility rating categories have changed relative to each other over the time period, but is not intended to show any trends in utility credit spreads as a whole.

The average credit spread differential for the 2009-2012 time horizon was 16 bps, compared to 15 bps during the 2012-2015 time horizon. This differential has increased above 20 bps for most of 2015. Based on the data provided, the last time the credit spread differentials were greater than 20 bps was in mid-2009, at which time the economy was still in recovery from the recent financial crisis. The credit spread differential between BBB/split rated and A-rated utilities has generally been greater during periods of market disruption. For example, in Q4 of 2008, the average credit spread differential between BBB/split rated and A rated utilities was 26 bps. This average credit spread differential further increased to 33 bps in Q1 of 2009, and 36 bps in Q2 of 2009.

The following table shows the range of credit spread differentials for the two time periods requested:

	2009-2012	2012-2015
Average	+16	+15
Max	+36	+25
Min	+9	+10

6.3 It appears that the average credit spread in utilities' issuances is less than the overall market debt issuance of the same rating. Please explain why.

Response:

The preamble to this question is referring to the delta in corporate new issue spreads for different credit rating categories (included on page 21, Figure 1 of the Application), and the delta in utility credit spreads for different credit rating categories (included on page 22, Figure 2 of the Application); however the question is referring to a comparison between the average credit spreads for utilities with the overall corporate debt market credit spreads. Therefore there appears to be a misinterpretation of Figures 1 and 2 of the Application as Figure 2 is not representative of utility indicative spreads themselves, but rather the delta between the credit spreads of BBB/split rated utilities and A-rated utilities. FEI has not provided any quantitative evidence in its Application suggesting that the average credit spreads for utilities is less than the credit spreads of debt issuances for the overall corporate debt market.

However, given that utilities have certain industry specific characteristics, such as a long life asset base, regulatory limits on leverage and return metrics, and potentially limited commodity exposure through regulation, in certain market conditions, credit spreads on utility issuances may be less than the credit spreads for debt issuances in the broader corporate market. Even within an A-rated category, the debt capital market has differing views of the long term risks of corporate sectors compared to the utility sectors, which will result in a different level of credit spreads for utility issuances as compared to corporates at certain points in time.

6.4 It appears that the average credit spread in the overall market is narrowing since January 2013 while the utilities sector is widening since July 2014. Please explain why.

<u>Response:</u>

Consistent with BCUC IR 1.6.3, the preamble to this question is referring to the delta in corporate BBB and A rated spreads (included on page 21, Figure 1 of the Application), and the delta in split and A rated utility credit spreads (included on page 22, Figure 2 of the Application). However, the question is stating that credit spreads themselves have decreased for corporate issuers and widened for utilities, which misinterprets the information contained in Figures 1 and 2 of the Application. An increase in utility spreads does not necessarily translate to a widening of the delta between selected BBB/split rating and A-rated utilities shown in Figure 2, as this delta is a relative measure. For example, such a widening could occur if spreads for A-rated utilities increased at a faster rate relative to BBB/split rating spreads or conversely, if BBB/split rating spreads decreased at a faster rate relative to A-rated utility spreads.

The spread differential will continue to vary between the split rated and A rated utilities, as well as BBB-rated and A-rated corporate issuers, and this variability is driven by many different factors at different points in time. For example, the deltas in Figures 1 and 2 would have widened during the financial crisis of 2008 and 2009 with a flight to higher quality credit, such as A-rated, rather than BBB-rated.

As shown in the response to BCUC IR 1.6.2, the utility spreads of split rated and A rated utility issuers have increased in recent quarters and are actually higher than the indicative spreads from 2012. In terms of how the utility spreads compare to the overall market, there will be many different market factors which cannot be summarized in an overall conclusion. However the relative widening of utility credit spreads in recent periods may be attributable to a broader market perception of risk around the Canadian utilities sector.

7.0 Reference: Exhibit B-1, Figure 4, p. 23

Corporate bonds

On page 23 of FEI's Application, Figure 4 shows the BBB-rated corporate bonds issuance by year and term from 2005 to 2015. FEI states: "As a regulated utility, maintaining the flexibility to access debt capital under various market conditions, and in particular for longer duration bonds, is critical."

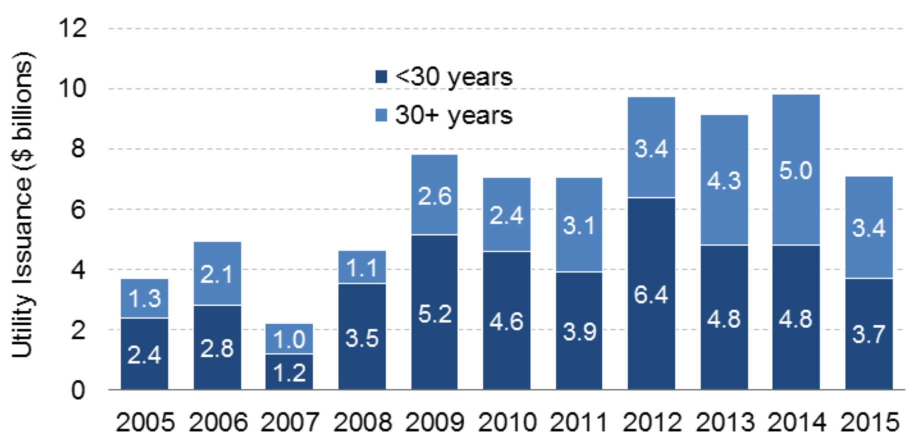
Since August 2012, the Bank of Canada target for the overnight rate has been one percent until early 2015. During 2015, the target overnight rate has decreased twice to 0.5 percent.[7]

7.1 In separate graphs and in similar format to Figure 4, please provide: (i) bond issuances from utilities; and (ii) A or better rating corporate bond issuances.

Response:

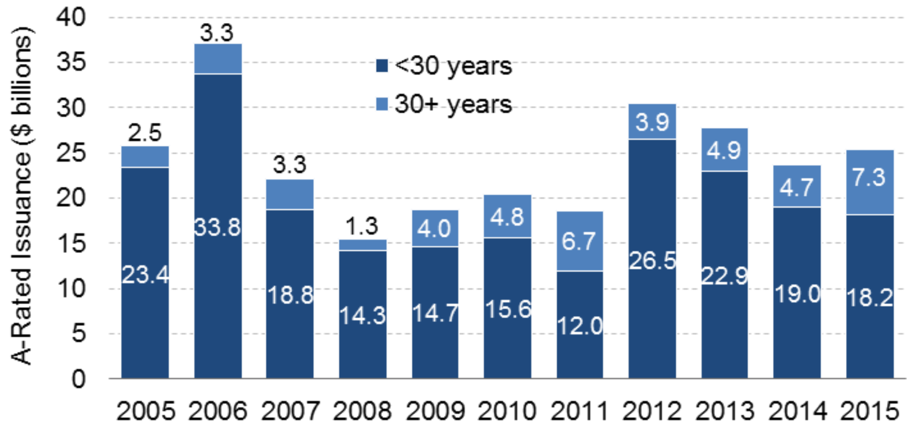
Please refer to the graphs below. When compared to the information in Figure 4 from FEI's Application, the second graph below confirms the greater access to 30 year and longer term bonds in the A credit rating category.

(i) Utility Bond Issuances by Year and Term from 2005 to November 30, 2015 (Source RBC Capital Markets)



(ii) A-rated Corporate Bond Issuances by Year and Term from 2005-November 30, 2015 (Source RBC Capital Markets).

7 http://www.bankofcanada.ca/core-functions/monetary-policy/key-interest-rate/.



7.2 Please discuss how the lowered interest rate environment has affected FEI's ability and cost of borrowing as compared to 2012.

Response:

FEI's cost of borrowing is fundamentally similar in 2015 as compared to 2012. FEI did not actually issue any long-term debt in 2012 so it is not possible to precisely compare FEI's current actual cost of debt with 2012. For comparative purposes, Exhibit JMC-3 in Mr.Coyne's evidence shows that the most recent average bond yield for an A rated utility was 3.89% as of August 2015, compared to 3.91% in June 2012. FEI does not consider this difference to be indicative of a significantly changed interest rate environment.

Maintaining FEI's A rating is critical to ensure continuing access to debt markets, should there be a market disruption similar to 2008 and 2009. While a similar capital market disruption would increase borrowing costs, with a resulting constraint on issuance capacity, maintaining an A credit rating would help to protect FEI's access to the markets in such an environment. Any downgrade to this rating could have an adverse impact to both the ability to borrow and cost of borrowing. The potential for a market disruption exists despite the current lower interest rate environment.

8.0 Reference: Exhibit B-1, pp. 20, 25;

Appendix A, Section 2 – Credit Rating Agency Reports, Moody's report on FEI dated July 20, 2015

Financial metrics

On page 20, FEI states that "[t]he ratings assigned to securities issued by FEI are reviewed by credit rating agencies on an ongoing basis. Currently FEI's unsecured long-term debt is rated as 'A3' by Moody's (the lowest level of the A category) and 'A' by DBRS (the middle level of the A category)."

On page 20, Table 2 provides Moody's rating grid for regulated utilities as follows:

Table 2: Moody's Rating Grid for Regulated Utilities

Broad Rating Factor	Factor Weighting	Rating Sub-factor	Sub-factor weighting
Regulatory Framework	25 %	legislative and judicial underpinnings of regulatory framework consistency and predictability of regulation	12.5 % 12.5%
Ability to recover costs and earn returns	25 %	timeliness of recovery of operating and capital costs sufficiency of rates and returns	12.5 % 12.5 %
Diversification	10 %	Market Position* Generation and Fuel Diversity**	5 % 5 %
Financial Strength	40 %	CFO Pre-WC[15] + Interest / Interest CFO Pre-WC / Debt CFO Pre-WC – Dividends / Debt Debt / Capitalization	7.5 % 15 % 10 % 7.5 %

* 10% weight for issuers that lack generation

** 0% weight for issuers that lack generation

On page 25, Table 3 provides its key financial indicators scores compared to minimum A3 rating per Moody's Utility Rating Methodology as follows:

Table 3: FEI's Key Financial Indicator Scores Compared to minimum A3 rating per Moody's Utility Rating Methodology[23]

	FEI's Score	A3 - Rating Threshold[24]	2011	2012	2013	2014
CFO pre-WC + Interest / Interest	Ba	4.5x	2.3x	2.5x	2.7x	2.8x
CFO pre-WC / Debt	Baa	19.0%	11.2%	14.5%	15.1%	14.4%
CFO pre-WC - Dividends / Debt	Baa	15.0%	6.6%	9.6%	8.0%	10.3%
Debt / Capitalization[25]	A	50.0%	47.4%	44.0%	43.6%	45.2%

Moody's credit opinion on July 20, 2015 stated:

> FEI's credit quality is driven by its credit supportive regulatory environment and its monopoly position. The company has a long term track record of earning its allowed return on equity and its cash flow continues to be highly predictable. This is offset by the company's weak financial metrics, with limited headroom at the current rating level, that are primarily a product of the allowed return on equity and the equity component of its capital structure.

On page 26, FEI provides Table 4 that shows a comparative analysis of utilities' credit metrics, allowed ROE and equity thickness.

8.1 It appears that Moody's favours FEI's regulatory environment and monopoly position to compensate for FEI's financial metrics that are below Moody's A3 – Rating Threshold. Please confirm that FEI has not been downgraded below A3 by Moody's since 2011.

Response:

FEI has not been rated below A3 since 2011. Moody's changed FEI's credit outlook to negative in 2013, with the following comment: "the BCUC's recent generic cost of capital decision (GCOC), which reduced both FEI's allowed ROE level and equity component for rates, is likely to weaken the company's financial metrics further and is the impetus for the company's negative ratings outlook." The Company's rating was eventually amended back to stable in June 2014.

8.2 Comparing the financial metrics in Table 3 from 2011 to 2014, it would appear that FEI has generally improved in the following areas: CFO pre-WC + Interest/Interest and CFO pre-WC - Dividends/Debt; and stayed relatively flat since 2012 in: CFO pre-WC/Debt and Debt/Capitalization. Given Moody's credit opinion, which appear to underweight financial metrics and in light of FEI's improvement in its financial metrics, would it be fair to say that FEI is less likely at risk of a credit rating downgrade based on financial metrics?

Response:

No. FEI is not less likely to be at risk of a credit rating downgrade due to financial metrics.

This is in part due to Moody's credit rating methodology, whereby Moody's considers a 40% weighting to financial metrics, but also considers a 25% weighting to Regulatory Framework.

A decision to reduce common equity or ROE may be viewed as undermining regulatory support that has otherwise supported FEI's rating in the face of traditionally weak metrics. This has been corroborated in Moody's June 2013 Credit Opinion on FEI which stated "the BCUC's recent generic cost of capital decision (GCOC), which reduced both FEI's allowed ROE level and equity component for rates, is …. the impetus for the company's negative ratings outlook."

Based on Table 4 on page 26, it would appear that FEI's financial metrics are less favourable in terms of Earnings Before Interest and Tax (EBIT) interest coverage when compared to the average DBRS Limited (DBRS) A-rated natural gas distribution and transportation companies. It also appears that FEI's financial metrics are less favourable in terms of EBIT interest coverage and debt to total capital when compared to the average electric distribution and transmission companies.

8.3 Please provide evidence as to whether or not any of these comparator companies received similar comments of FEI from credit analysts regarding supportive regulatory environment and/or other unique circumstances that allow the deviation from the credit agency's rating methodology.

Response:

FEI does not agree with the statement that Moody's has deviated from its methodology in determining FEI's credit rating. A supportive regulatory environment is one factor that Moody's considers within its methodology. Although FEI's credit metrics are lower than comparator companies, these metrics represent another element of the overall rating methodology. Moody's rating grid presented in FEI's credit rating report outlines the other considerations within their rating methodology. The factors and weighting are as follows:

1. Regulatory Framework: 25%
2. Ability to Recover Costs and Earn Returns: 25%
3. Diversification: 10%
4. Financial Strength: 40%

FEI has reviewed credit rating agency comments for some of the comparator companies noted in Table 4 of the Application and found that many of them contain similar language around a supportive regulatory environment being a key consideration in the rating.

For example, Enbridge Gas Distribution's recent DBRS rating reports stated the following: "The Company's ratings are based on its low-risk business profile, supported by a reasonable and stable regulatory environment in Ontario and a strong franchise area with a large customer base of over two million."

Similarly, the recent DBRS rating report for Gaz Metro Inc. notes that the "business risk profile is strongly supported by (1) regulated gas distribution operations in Québec, which benefit from a supportive regulatory framework with no exposure to commodity price risk and a rate stabilization program…".

Both statements provide evidence that a supportive regulatory environment is a consideration in a credit rating agency's methodology. While credit metrics represent a large weighting of the overall methodology, weak credit metrics have the ability to be offset through qualitative factors such as strong regulatory support. However, Moody's clearly notes in FEI's July 2015 rating report that a material adverse regulatory decision could result in a rating downgrade.

8.4 To the extent possible, please provide a similar comparison table to Table 4 using Moody's credit opinions and compare the four key financial indicator scores considered by Moody's.

Response:

Please refer to the table below for Moody's credit metrics based on the most recent Moody's credit rating opinions. Companies which were included in Table 4 but excluded from the table below are not rated by Moody's.

		CFO pre-WC+Interest/Interest			CFO pre-WC/Debt			CFO pre-WC-Dividends/Debt			Debt/Capitalization		
Fiscal Year	**Moody's Rating**	12 x	13 x	14 x	12 %	13 %	14 %	12 %	13 %	14 %	12 %	13 %	14 %
FortisAlberta Inc.	Baa1	5.2	4.7	4.4	21.6%	18.2%	17.5%	18.2%	14.9%	14.0%	56.0%	55.2%	53.9%
FortisBC Inc.	Baa1	3.3	3.5	3.8	9.6%	10.1%	11.5%	7.3%	5.7%	8.9%	55.8%	55.1%	54.8%
Hydro One Inc.	A3	4.0	4.0	3.9	13.6%	14.1%	13.4%	10.1%	12.1%	10.7%	57.6%	54.9%	53.4%
Newfoundland Power[2]	Baa1	3.3	3.9	4.2	15.8%	20.1%	21.7%	13.8%	15.8%	17.5%	51.9%	49.7%	49.4%
TransCanada Pipelines Limited[1]	A3	3.3	3.7	3.7	12.7%	13.6%	13.3%	6.8%	8.1%	7.9%	N/A	N/A	N/A
Average		**3.8**	**4.0**	**4.0**	**14.7%**	**15.2%**	**15.5%**	**11.2%**	**11.3%**	**11.8%**	**55.3%**	**53.7%**	**52.9%**
FortisBC Energy Inc.		**2.5**	**2.7**	**2.8**	**14.5%**	**15.1%**	**14.4%**	**9.6%**	**8.0%**	**10.3%**	**44.0%**	**43.6%**	**45.2%**

1 - Metrics per Moody's report for TransCanada Pipeline use FFO (Funds from operations) instead of CFO. The Moody's report also does not present Debt/Capitalization metrics for this company.

2 - Newfoundland Power's 2014 metrics include financial results up to September 30, 2014. Due to the date of report production (Jan 19, 2015), it is unlikely that 2014 year end results were available.

9.0 Reference: Exhibit B-1, pp. 20, 25

The approach of rating agencies

FEI's Application on page 20 notes that "[c]urrently FEI's unsecured long-term debt is rated as 'A3' by Moody's" and on page 25 notes that "with the exception of Debt to Capitalization ratio, all financial metrics are below the Moody's designated threshold for an A3 rating" and shows that this has been the case for each of the four years shown in Table 3.

9.1 Please explain if this indicates that Moody's has not applied its "minimum" credit metric ratio requirements in the case of FEI.

Response:

Under Moody's rating methodology, there is no defined "minimum" level of credit metric that is applied to a specific rating. Moody's considers credit metrics as one aspect of the overall rating methodology, and assigns a weighting to each factor that is considered in the final rating. In its recent credit rating report, Moody's assessed FEI a rating score which is below an A level for each of the financial metrics it considers in its methodology, with the exception of debt to capitalization ratio. However, Moody's has given FEI an A rating score or higher in several of its other rating factors and sub-factors, such as regulatory framework and diversification. The higher rated scores in these grid factors have allowed FEI to maintain its A3 rating. However, further weakening of these metrics in connection with an adverse regulatory decision on capital or ROE, would place downward pressure on the rating. FEI also notes that Moody's has stated that a forecast of sustained deterioration in credit metrics including CFO/pre-WC/Debt of less than 11%, could change the rating downwards.

9.1.1 In the case of FEI, should the Commission conclude that its actual credit metrics indicated in Table 2 were sufficient to achieve the A3 rating in the context of how Moody's viewed its regulatory framework, ability to recover costs and earn returns and its diversification?

Response:

Please refer to the responses to BCUC IRs 1.9.1 and 1.8.2 for further context. Please also refer to the July 2015 rating report issued by Moody's to FEI included in Appendix A of the ROE Application. The Rating Factors grid included in that report illustrates that FEI, while displaying weak credit metrics, offsets that by its regulatory framework and position of diversification in place, which allow it to receive an A-level rating. This grid also considers FEI to score lower than A level in the sub-categories of Sufficiency of Rates and Returns.

10.0 Reference: Exhibit B-1, Table 4, p. 26

Capital structures and credit metrics of sample Canadian utilities

FEI's Table 4 provides information on a sample of Canadian utilities. However, it does not include several relatively pure-play Canadian regulated utilities that issue debt on a standalone basis and that issue debt at the utility level and have standalone credit ratings.

10.1 Please provide a revised version of Table 4 that incudes Fortis Inc. and CU Inc. and any other relatively pure play regulated distribution utilities with standalone debt ratings that FEI and/or Mr. Coyne deem appropriate to include.

Response:

Table 4 on page 26 of FEI's Application was intended to cover some of the major natural gas and electric utilities that are regulated by Canadian regulators and not their non-regulated holding companies.

FEI has provided a revised version of Table 4 which includes similar financial metrics obtained from recent credit rating reports for Fortis Inc. and CU Inc. These companies are holding companies of regulated utilities, and therefore do not have an allowed ROE or equity thickness attributable to them.

		EBIT Interest Coverage			Debt to Total Capital		
Fiscal Year	**DBRS Rating**	12 x	13 x	14 x	12 %	13 %	14 %
CU Inc.[1]	A (high)	2.7x	2.7x	2.67x	57.1%	57.7%	60.2%
Fortis Inc.[2]	A (low)	2.17x	2.19x	1.91x	56.5%	56.5%	61.7%

1 - Metrics are labelled as EBIT Gross Interest Coverage (times) and total debt in capital structure per the CU Inc. ratings report.
2 - All 2014 figures are reported for 12 months ended September 30, 2014 due to timing of the report production, where as all other years are as at December 31. Also noted that the figures provided represent the consolidated metrics as per the most recent DBRS rating report.

10.1.1 Based on the revised sample, please summarize the range of credit metrics, equity ratios and allowed ROEs that were associated with a credit rating of A (low).

Response:

As noted in response to BCUC IR 1.10.1, the companies that were requested to be included in the revised sample are considered holding companies of regulated utilities, and are not regulated by Canadian regulators. Therefore these companies do not have an allowed ROE or equity thickness associated with them.

11.0 Reference: Exhibit B-1, pp. 27–31

Debt issuance constraint and forecast credit metrics

FEI discusses its debt issuance capacity and possible constraints under its Trust indenture. FEI notes that it will lose the benefit of certain purchase money mortgage debt that is excluded from the Trust Indenture coverage test.

11.1 Please discuss whether FEI's potential debt issuance constraint arises only as a result of the Trust Indenture and is not caused by any forecast decline in the credit rating or credit metrics.

Response:

To clarify, the FEI Trust Indenture contains an issuance test that needs to be passed before new debentures can be issued. The debt issuance capacity referred to in the preamble that FEI discusses is the amount of new debt that may be issued, and the possible constraint is the reduction in that debt issuance capacity that may constrain the ability to issue new debt under the Trust Indenture issuance test.

There is no specific test tied to credit ratings or credit metrics, but debt issuance capacity could be affected should there be a decline in credit ratings or credit metrics which would affect the cost of borrowing. As explained on page 27 of FEI's Application, FEI's issuance capacity is impacted, among other things, by its approved ROE and capital structure as well as the market-driven cost of debt. If there were a decline in the allowed ROE and/or equity thickness there would be implications on issuance capacity, as illustrated in Table 6 of the Application. In addition, a decline in allowed ROE and/or capital structure would lead to a decline in credit metrics, which in turn could lead to a credit rating downgrade and the resulting increased cost of borrowing. The increased cost of borrowing would further constrain FEI's debt issuance capacity.

11.1.1 Please discuss if FEI has other options under the Trust Indenture such as issuing purchase money mortgage debt or other secured debt that is excluded from the Trust Indenture coverage test.

Response:

As explained on page 28, footnote 30 of FEI's Application, the Trust Indenture limits FEI's ability to issue secured debt. Secured debt is restrictive and inefficient as it places a direct claim over assets on behalf of debt holders. It is more appropriate for an A-rated utility to have credit metrics that support its debt issuance needs as opposed to having to resort to less efficient financing instruments.

11.2 Please provide a forecast of FEI's credit metrics (including but not limited to those listed in Table 3 at page 25) for the years 2016 and 2017 based using the currently approved ROE and equity ratio and using scenarios of plus or minus 100 basis points in the ROE and equity ratio.

Response:

FEI does not have detailed forecast information available in order to calculate 2016 and 2017 credit metrics. However, for illustrative purposes, FEI has provided a table below which calculates the Moody's credit metrics under sensitivity scenarios of plus or minus 100 basis points in ROE and equity. The re-calculated credit metrics were determined using 2014 actual financial results and metrics as a proxy, while adjusting for post-amalgamation ROE and deemed equity thickness, approved 2015 rate base, and variances from formulaic O&M, net of the earnings sharing mechanism. These base metrics have also been adjusted for the impacts of capital in progress amounts up to 2016 as identified through FEI's Annual Review filing. During construction, these major capital projects are expected to put additional pressure on cash flow credit metrics due to the impact of financing costs prior to inclusion in rate base.

The metrics could be further negatively impacted if other significant projects are approved, such as projects discussed in the response BCUC IR 1.11.3.

Adjusted Moody's Metrics [1]	Base Metric [3]	39.5% Equity 8.75% ROE	37.5% Equity 8.75% ROE	38.5% Equity 9.75% ROE	38.5% Equity 7.75% ROE
(CFO Pre-W/C + Interest)/Interest Expense	**2.6x**	**2.6x**	**2.6x**	**2.7x**	**2.5x**
CFO Pre-WC/Debt	**12.6%**	**12.9%**	**12.3%**	**13.1%**	**12.0%**
CFO Pre-WC-Dividends/Debt [2]	**9.0%**	**9.2%**	**8.9%**	**9.1%**	**8.9%**
Debt/Book Capitalization	**47.4%**	**46.8%**	**48.1%**	**47.4%**	**47.5%**

1 - The adjusted metrics are calculated using post-amalgamation capital structure and ROE. All other balances are assumed to be consistent with 2014 actual amounts as reported by Moody's.

2 - Assumes a dividend payout ratio of 75% of incremental earnings under each scenario.

3 - The base credit metric forecast adjusts 2014 actual results for approved 2015 mid-year rate base, expected incremental earnings in 2015 through earnings sharing mechanism, and estimated capital spending associated with work in progress for 2015 and 2016.

11.3 Please provide an estimate of forecast capital spending in each year and the forecast amount of debt and equity forecast to be raised net of cash generation and dividend payments.

Response:

FEI is currently in a high capital growth period, driven primarily by a number of large projects, each at various stages of consideration, approval, development or construction. These projects are listed and described below. The timing of expenditures and the approval of certain of the projects over the 2016-2018 time period is uncertain, but for purposes of ensuring access to capital as it relates to the Company's Trust Indenture coverage test, FEI has considered the financing requirements of all of the projects during this time period.

This financial information has been provided in the context of how capital expenditures and debt requirements could potentially put pressure on FEI's debt issuance capacity. As such, this financial information is not representative of a forecast, as there are various agreements and approvals that must occur in order for the capital, debt and equity figures to materialize.

The major approved and potential capital projects over this period are as follows:

- The Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) has estimated project costs of approximately $240 million, the majority of which is expected to occur from 2016-2018.
- For the Coastal Transmission Projects, the total expected cost is estimated to be approximately $160 million with the majority of these expenditures expected to occur in 2016-2017.
- The Tilbury 1A project spend is expected to be approximately $440 million. FEI currently expects Tilbury to be substantially completed by 2016.
- If approved, capex for the Woodfibre project is estimated to be approximately $600 million.
- Tilbury 1B project has a conditional approval from an Order in Council ("OIC") from the Government of British Columbia and has an estimated completion cost, including AFUDC, of $450 million. Timing for this project is dependent on FEI project approval and meeting OIC conditional approval requirements.

The following table shows the required debt and equity financing requirements for the projects, subject to the timing and approval uncertainties described above:

	2016	2017	2018
Approved Major Capital Projects	130,000	160,000	205,000
Potential Growth Projects[3]	-	525,000	525,000
Expected Total Capital Expenditures[2]	**130,000**	**685,000**	**730,000**
Debt Financing[1]	80,000	420,000	450,000
Equity Financing	50,000	265,000	280,000

1 - Excludes refinancing of $200 million of debt maturing during the period

2 - Excludes financing required of formulaic capital which is partially funded through depreciation cost.

3 - Relates to Tilbury 1B expansion and Woodfibre

12.0 Reference: Exhibit B-1, Appendix A, Section 2 – Credit Rating Agency Reports, S&P report on Fortis Inc. dated April 30, 2015, p. 6

Investor required returns

The April 30, 2015 Standard & Poor's Ratings Services (S&P) debt rating report for Fortis Inc. indicates that Fortis Inc.'s return on common equity in the past five years beginning with 2014 was 4.7 percent, 6.9 percent, 7.4 percent, 7.8 percent and 7.9 percent.

12.1 Can FEI or Mr. Coyne explain if Fortis Inc.'s goodwill (the payment of premiums) to acquire regulated assets has lowered Fortis Inc.'s ROE?

Response:

The pre-amble is referring to the return on common equity per the S&P rating report, however it is not clear whether the question is referring to the anticipated ROE or earned ROE of Fortis Inc. As Fortis Inc. is a holding company of regulated utilities, it does not have an allowed ROE.

If the question is referring to the earned ROE subsequent to the acquisition of goodwill, the goodwill may result in a lower return on common equity for Fortis Inc. in the short-term, however it could be offset by longer term benefits. For example, the acquisition of regulated businesses and any related goodwill may bring with it numerous other longer-term advantages such as geographic diversification, cost synergies, acquisition of a strong management team for succession planning, diversification of businesses, greater access to capital markets due to scale and other strategic merits that would be attractive to investors, and which the market would view favorably, but which may not be realized in its reported ROE in the short-term. Additionally, if the rate base of the acquired utility is expected to grow significantly, Fortis Inc. may be willing to pay a premium knowing that this premium will be offset through future returns. Furthermore, goodwill is anticipated to be recovered through future returns, thus providing an appropriate return on equity over time. Considerations when making an acquisition go beyond the achieved or allowed ROE. Investors look at the amount they've invested in acquiring shares, share appreciation, and the return they will receive in the long-term and not simply the financial statement ROE recorded during a relatively short time frame.

Fortis Inc.'s returns on common equity from 2012 to 2014, as reported by S&P, were likely affected by the significant acquisitions of CH Energy (2012) and UNS Energy (2014), which would have produced lagging return on common equity as one-time acquisition costs were absorbed and ownership transitions took place. The full financial benefits of these acquisitions would typically occur after this transition period as the full contribution of pro-forma earnings and synergies are realized, thus the calculated ROEs are not reflective of investors' long-term expected returns.

Finally, as acknowledged by the Commission in prior decisions, conditional on the existence of appropriate "ring-fencing" conditions upon Fortis Inc, any premium paid to acquire the equity capital of other regulated entities is not relevant to determining an appropriate capital structure and return on equity for FEI:

> *"The Commission Panel has considered the premium paid by Fortis Inc. to acquire the equity capital of TI in 2007. As was the case with respect to the premium paid by KMI for the shares of TI discussed in the 2006 ROE Decision there is no evidence before the Commission that any of the premium paid by Fortis Inc. will be included in any of the Companies' rate bases and recovered from their customers. Further, as was the case with the KMI acquisition, the Commission imposed "ring-fencing" conditions upon Fortis Inc. The Commission Panel considers that the Commission's role is to determine an appropriate capital structure and return on equity for Terasen and that the acquisition of TI by Fortis Inc. is not relevant to the Commission Panel's determination in this regard.[8]"*

The subject of "acquisition premia" has been discussed in more detail in Mr.Coyne's response to BCUC IR 1.33.2 and 1.33.3.

12.1.1 Can FEI or Mr. Coyne discuss the ability of Fortis Inc. to attract investor capital while earning ROEs that have apparently not exceeded 8 percent in the past five years and any implications of this on the returns apparently required by investors?

Response:

The question presents a faulty premise, as investors will focus on long-term expected share returns determined by dividends and capital appreciation when considering investment in a specific company, and not the historic accounting measure of ROE. Fortis Inc. has a long and consistent history of dividend growth (a record 42 consecutive years of annual dividend increases) which attracts investors. For example, Fortis Inc. has improved its dividend per common share from $1.21 in 2012 to $1.25 in 2013 and $1.30 in 2014. ROE is important from a valuation perspective to the extent it drives dividends or capital appreciation, the two factors which determine investor returns. It is also worth noting that recent ROEs, as reported by S&P, were impacted by Fortis Inc.'s significant utility acquisitions, and are not reflective of long-term investor expectations. For more information please refer to the response to BCUC IR 1.12.1.

[8] 2009 Cost of capital Decision, page 15.

13.0 Reference: Exhibit B-1, pp. 2–3; Appendix A, Section 2 – Credit Rating Agency Reports, DBRS report on FEI dated January 14, 2015;

FortisBC Energy Utilities Application for Reconsideration and Variance of Commission Order G-26-13 on the FortisBC Energy Utilities' Common Rates, Amalgamation and Rate Design Application, Decision dated February 26, 2014, p. 30

FEI's business risks pre and post-amalgamation

On page 2 of Exhibit B-1, FEI notes that one notable change since the GCOC Stage 1 proceeding is the amalgamation of FEI with FEVI and FEW. On December 31, 2014, the three companies amalgamated. The amalgamated entity is carrying on business as FEI, and in this proceeding may be referred to as "FEI", "amalgamated FEI" or "FEI Amalco" as the context requires. On page 3 of Exhibit B-1, FEI states:

> While amalgamation is a factor affecting FEI's business risk that should be considered, it is not the primary justification for FEI's request to increase FEI's equity thickness or ROE. FEI Amalco remains a large natural gas distribution utility, regulated by the BCUC, whose core business is to provide space and water heating to its customers.

On page 30 of the Commission decision on FortisBC Energy Utilities (comprising of FEI, FEVI and FEW) Application for Reconsideration and Variance of Commission Order G-26-13 on the FortisBC Energy Utilities' Common Rates, Amalgamation and Rate Design Application, the Commission stated:

> The Commission Panel finds that a final determination as to the appropriate ROE and capital structure for the amalgamated entity must be deferred to the Generic Cost of Capital Proceeding. However, from the evidence and submissions filed in this Proceeding, the Commission Panel would recommend that the capital structure and ROE remain the same for the amalgamated entity as for FEI, as the low risk benchmark utility. <u>In this Panel's view, the major benefit to the shareholder of the approval for the FEU to amalgamate and adopt postage stamp rates is a reduction in the risk faced by the two smaller utilities. The Panel does not see this risk as being transferred to the larger amalgamated entity. Rather, in this Panel's view, the risks attributable to the small size and small customer bases of FEW and FEVI combined with their higher rates, as highlighted in this Application, will be eliminated as these utilities are subsumed into a single, larger entity</u>. [Emphasis added]

On page 1 of the DBRS rating report dated January 14, 2015, it states:

The business risk profile of the amalgamated entity would not be materially different from FEI's pre-amalgamation business risk level. The amalgamated entity will have a larger customer base than FEI's pre-amalgamation customer base, and the risk previously attributable to FEVI's and FEW's competitive position and smaller size is eliminated.

13.1 In the FortisBC Energy Utilities Application for Reconsideration and Variance of Commission Order G-26-13 on the FortisBC Energy Utilities' Common Rates, Amalgamation and Rate Design Application Decision, the Commission recommended that the capital structure and ROE should remain the same for the amalgamated entity as for FEI, please discuss FEI's views specifically with respect to the underlined in the preamble.

Response:

As explained on page 1 of Appendix C – Business Risk, amalgamation addressed FEVI's and FEW's risks related to greater concentration of assets within a small service area and a less diverse customer and economic base. Therefore, FEI agrees with the Commission Panel findings as underlined in the preamble, namely that risks attributable to the small size and small customer bases were not transferred to the larger amalgamated entity. There are certain risks that were unique to FEVI and FEW that are now transferred to FEI, notably the supply risk associated with submarine crossings, but this risk is relatively low. As a result, amalgamation is not the primary justification for FEI's request to increase FEI's equity thickness or ROE.

13.2 Does FEI believe that there are synergies and/or other features of a larger utility in FEI Amalco serving an expanded service area which may reduce the risk of the utility and strengthen the business? Please discuss.

Response:

No. The amalgamation did not create any meaningful synergies for the amalgamated entity nor reduce FEI Amalco's risk due to the expanded service area. These issues were thoroughly discussed in FEU's amalgamation reconsideration application[9] and FEU's final submission to the Commission in the original amalgamation proceeding[10] respectively.

---

9 FEU Amalgamation Reconsideration Application, pp. 2-3.
10 FEU Final Submission, Original Amalgamation Application, pp. 91-93.

As explained in FEU's amalgamation reconsideration application (pp. 2-3) FEI, FEVI and FEW were highly integrated prior to the amalgamation. The integration of the FEU was achieved in 2004 through the Utilities Strategy Project. All of the FEU shared common executives, management, policies (both operational and support), systems and back office functions. As well, the FEU shared operational activities, including but not limited to the customer service, gas supply, gas control, dispatch, engineering and emergency response. Therefore amalgamation had minimal impact in the degree of integration and any potential synergies from amalgamation were not material.

With respect to the impact of amalgamation on size and cost of capital, the following excerpt from FEU's final submission in the original amalgamation proceeding is provided and reflects FEI's position:

> *"In section III of her opinion, Ms. McShane describes how the size of a firm can have an impact on its cost of capital. The question is whether FEI Amalco would be perceived by the capital markets as materially larger than pre-amalgamation FEI. Ms. McShane tests whether FEI Amalco would be perceived as materially larger than pre-amalgamation FEI by comparing the capitalization of pre-amalgamation FEI and FEI Amalco to an analysis of firm size and costs of capital performed annually by Morningstar/Ibbotson Associates. The results of this comparison show that both pre-amalgamation FEI and FEI Amalco would qualify as large cap stocks and would most likely fall within the same market capitalization decile. As stated by Ms. McShane: "In other words, while FEVI and FEW (combined) are not of immaterial size, FEI has already reached sufficient market capitalization such that, from a capital markets perspective, the increase in size arising from amalgamation would not lower its cost of capital.""*[11]

The issue of amalgamated FEI's increased size was also studied on page 99 of Mr. Coyne's testimony where he confirms that FEI Amalco's size had no impact on FEI's risk profile:

> *"Through amalgamation, FEI has increased its size but since it was already a large gas distributor, there has been no impact on FEI's risk profile due to the increased size of the amalgamated entity".*

13.3 Does FEI agree with the DBRS rating report characterization of FEI Amalco as referenced in the preamble? If so, would it be reasonable to exclude any considerations on the effect of amalgamation and instead focus on capital markets and FEI's business risk since 2012? If not, please explain why.

[11] FEU Final Submission, Original Amalgamation Application, page 94, paragraph 246.

Response:

FEI agrees with both Moody's and DBRS' assessments that the amalgamation was largely credit neutral to FEI. It should be noted that credit rating agencies do not consider the risk to equity investors.

As presented in Table C-2 of Appendix C (column titled Risk Status Change due to Amalgamation Alone), FEI believes that with the exception of the security of supply risk factor, amalgamation did not impact any of the risk categories. The incremental supply risk is caused by FEVI's and FEW's regional infrastructure constraints and dependency on a single pipeline system that traverses challenging terrain. Nevertheless, FEI agrees with the Commission Panel finding in the GCOC Stage 2 Decision where it states that "there are additional supply interruption risks faced by FEVI and FEW when compared to the Benchmark but they are marginal. Therefore, the Panel places minimal weight on this factor"[12]. So while it is an overstatement to say that one should "exclude any considerations" of amalgamation, FEI agrees that the focus should be on capital markets and changes in FEI's business risk since 2012.

13.4 To the best of FEI's knowledge, are there any recent (e.g., past ten years) amalgamation of smaller gas utilities in Canadian jurisdictions? If there have been, what have been the impact on the business risk profile to the entities that have absorbed the smaller and/or riskier utilities?

Response:

FEI is not aware of any recent similar examples of natural gas utilities amalgamating in other Canadian jurisdictions.

[12] GCOC Stage 2 Decision, p.56.

14.0 Reference: Exhibit B-1, Appendix A, Section 1 – Financial Information, FEI Consolidated Financial Statements, FEI Consolidated Balance Sheet (US GAAP), p. 3

Goodwill and equity ratio

The consolidated balance sheet of FEI shows that there is a good will asset valued at $913 million for both years 2014 and 2013. Note 7 of the financial statements indicates that the excess purchase price (goodwill) paid by Fortis Inc. on the acquisition of FEI has been recorded in FEI's financial statements using push-down accounting and that this included recognizing additional paid-in capital (equity) in the amount of the goodwill recognized.

FEI's financial statements for the year ended December 31, 2011 did not include any goodwill and indicated equity of $1049.5 million. However, FEI's financial statements for the year ended December 31, 2012, after the adoption of US GAAP, show that on December 31, 2011 FEI had goodwill of $769 million and equity of $1891 million.

14.1 Please clarify that FEI had no goodwill value on its balance sheet until it adopted the US GAAP. Please comment on the "goodwill" item in terms of it being an asset in a regulated utility, its impact on credit agency rating determinations and its impact on the credit metrics of FEI.

<u>Response:</u>

Confirmed that FEI had no goodwill on its balance sheet until it adopted US GAAP. The goodwill recognized upon adoption of US GAAP represents the excess of the purchase price over the fair value of the shares acquired by Fortis Inc. for the acquisition of FortisBC Energy Inc. (named Terasen Gas Inc. at the time) which took place on May 17, 2007. At the time of acquisition, FEI reported its financial statements under Canadian GAAP which did not require the use of pushdown accounting.

Upon FEI transitioning to US GAAP in 2012, guidance for business combinations required the application of push down accounting. Push-down accounting refers to the establishment of a new accounting basis for an acquired entity in its separate, standalone financial statements based on an acquisition that results in the acquired entity's outstanding shares becoming substantially wholly owned. As a result of these rules under US GAAP, the establishment of goodwill and additional paid in capital relating to "push down" of the excess purchase price paid was required on the financial statements.

Although goodwill is recognized on the financial statements under US GAAP, it is excluded from FEI's rate base and therefore FEI does not earn a regulated return on this amount.

In its credit opinion dated August 8, 2012, DBRS discusses some of the US GAAP transition adjustments including the recognition of goodwill and notes that "the change in accounting reporting did not have a material impact on the credit profile of [FEI]." In the Financial Profile section of the DBRS rating reports issued, DBRS calculates the Debt to Capitalization with and without US GAAP accounting adjustments. Although both metrics are presented in the report, DBRS includes the ratio which excludes the goodwill adjustment in its consideration of the rating. Table 4 of the Application also presents the ratio adjusted to exclude goodwill.

Moody's credit report subsequent to the transition in 2012 shows an improvement in the debt to capitalization ratio and notes that "the change in the ratio is merely a function of US GAAP accounting rules as goodwill…is now recognized as an asset on FEI's balance sheet with an offset to paid in capital." Moody's has therefore recognized and included the goodwill balance in its determination of credit metrics. FEI notes the fact that the Debt/Capitalization ratio was positively impacted by the adoption of US GAAP in the footnotes to Table 3 of the Application.

14.2 In a case where goodwill does not earn any cash return, please explain if any goodwill on a utility balance sheet must be financed with 100 percent equity in order not to weaken the credit metrics that would apply in the absence of goodwill.

<u>Response:</u>

FEI has financed the goodwill on its consolidated balance sheet with equity. Goodwill is excluded from rate base and therefore does not earn a regulated return.

As noted in the response to BCUC IR 1.14.1, DBRS examines the debt to capitalization ratio after adjusting for US GAAP accounting changes in its consideration of FEI's rating. Therefore, the existence of a goodwill balance has not fundamentally strengthened or weakened FEI's DBRS credit metrics.

Moody's has included the equity financing of the goodwill balance in their calculation of the debt to capitalization ratio. As stated in the Application, FEI's debt to capitalization ratio, as calculated by Moody's, has benefitted from the inclusion of the equity financing of goodwill. Although FEI's debt to capitalization credit metric improved compared to the regulated debt to capitalization metric due to the equity financing of goodwill, there was no impact on the other primary Moody's credit metrics nor the overall Moody's rating as a result of the change.

14.3 Please describe how FEI's goodwill is financed.

Response:

FEI's goodwill is financed through equity. As noted in response to BCUC IR 1.14.1, when FEI transitioned to US GAAP accounting standards, a goodwill asset and a corresponding "Paid in Capital" amount was recognized which is considered an equity contribution.

14.4 It appears that FEI had no goodwill under Canadian GAAP but has considerable goodwill under US GAAP. Please explain if the change to US accounting had any material impact on the credit metrics as calculated by the rating agencies

Response:

Please refer to the response to BCUC IR 1.14.1.

15.0 Reference: Exhibit B-1, pp. 17, 19; Appendix A, Section 1 – Financial Information, FEI Management Discussion & Analysis for the Year Ended December 31, 2014 dated February 19, 2015, p. 11; Section 2 – Credit Rating Agency Reports, DBRS report on FEI dated January 14, 2015

Credit agency rating

On page 17 of Exhibit B-1, FEI submits that credit agencies:

> …are especially sensitive to (i) the proportion of common equity in a utility's capital structure as it provides security for investors lending money to a utility, and (ii) the cash generated by the allowed returns to ensure that the interest on the debt of the utility can be serviced. The combination of an upward trend in FEI's business risk and relatively weak financial metrics that impact access to capital, demonstrate that FEI's common equity ratio should be increased to 40 percent.

On page 19 of Exhibit B-1, FEI states:

> One of the primary determinants of FEI's credit rating is its financial metrics, which are currently viewed by the rating agencies as being below the range acceptable for an A rating. The lower financial metrics are due to FEI having a common equity ratio and allowed ROE that are at the lower end of the range of comparable utilities. An increase in FEI's common equity component will improve FEI's financial credit metrics and support the likelihood of FEI maintaining its A-category credit rating.

On page 11 of the FortisBC Energy Inc. Management Discussion & Analysis for the Year Ended December 31, 2014 in Appendix A, it states:

Credit Ratings

Securities issued by the Corporation are rated by DBRS Limited ("DBRS") and Moody's Investors Service ("Moody's"). The ratings assigned to securities issued by the Corporation are reviewed by these agencies on an ongoing basis.

The table below summarizes the ratings assigned to the Corporation's various securities as at December 31, 2014:

Credit Ratings	DBRS	Moody's
Commercial paper	R-1 (Low), Stable Trend	-
Secured long-term debt	A, Stable Trend	A1, Stable Outlook
Unsecured long-term debt	A, Stable Trend	A3, Stable Outlook

In June 2014, Moody's affirmed the long-term credit ratings of the Corporation of A1 for secured long-term debt and A3 for unsecured long-term debt and changed the ratings outlook to stable from negative.

In January 2015, DBRS affirmed the long-term credit ratings of the Corporation after the completion of the amalgamation on December 31, 2014.

The DBRS rating report dated January 14, 2015 states:

> Starting in 2015, the new amalgamated entity will have a return on equity (ROE) of 8.75% and a deemed equity component of the capital structure of 38.5%, which is unchanged from 2014 for FEI. As a result, FEI's financial metrics are expected to remain within DBRS's 'A' rating guidelines.

15.1 On page 17 of its Application, FEI presented evidence from the common equity perspective only; and on page 19, FEI presents its views from both equity thickness and return on equity perspective. Please provide data to show the equivalent of 1 percent increase in common equity percentage in capital structure in terms of increase in ROE and the equivalent of 1 percent increase in ROE in terms of increase in common equity percentage.

Response:

The requested information is provided below using FEI's 2014 Approved rate base (on an amalgamated basis). To achieve the same return as provided by a 1% increase in equity, FEI would require an ROE of 8.98%. To achieve the same return as provided by a 1% increase in ROE, FEI would require an equity thickness increase to 42.9%.

1% increase in Equity Thickness	2014 Approved Rate Base	ROE	Equity	Equity Earned Return
8.75% ROE, 38.5% Equity	3,618,763	8.75%	38.50%	121,907
8.75% ROE, 39.5% Equity	3,618,763	8.75%	39.50%	125,073
Change in Equity Earned Return				3,166
8.75% ROE, 38.5% Equity	3,618,763	8.75%	38.50%	121,907
X.XX% ROE, 38.5% Equity	3,618,763	**8.98%**	38.50%	125,073
Change in Equity Earned Return				3,166

1% increase in ROE	2014 Approved Rate Base	ROE	Equity	Equity Earned Return
8.75% ROE, 38.5% Equity	3,618,763	8.75%	38.50%	121,907
9.75% ROE, 38.5% Equity	3,618,763	9.75%	38.50%	135,839
Change in Equity Earned Return				13,932
8.75% ROE, 38.5% Equity	3,618,763	8.75%	38.50%	121,907
9.75% ROE, XX.XX% Equity	3,618,763	8.75%	**42.90%**	135,839
Change in Equity Earned Return				13,932

15.2 Moody's changed FEI's ratings outlook from negative to stable. In FEI's view, what would have been the trigger that prompted Moody's to alter the outlook?

Response:

FEI cannot speculate as to the exact trigger that prompted the revision of the ratings outlook, as FEI was not privy to the discussion of the ratings committee. A new analyst began to cover FEI in 2014 that may have had a different view of the relative rating components and felt that removal of the negative watch was warranted. FEI's understanding is that the negative outlook was driven by ROE and capital structure decisions in 2013 which necessitated a more focused outlook on the overall elements of the rating.

As noted in Moody's announcement of the rating action in June 2014 "The change in the outlooks for the FortisBC entities reflects an upward revision of some qualitative scores following a more detailed analysis of the Provincial regulatory framework and comparison to peers, particularly those in the United States. This has offset the reduction in allowed return on equity and equity ratios that followed the BCUC's last generic cost of capital decision that led to the negative outlook. As a result of the credit supportive regulatory framework, the FortisBC entities have an established long term track record of earning their allowed returns on equity and generating cash flow that we expect to remain highly predictable." However, Moody's does note in recent credit opinion reports that a material adverse regulatory decision could result in a rating downgrade.

15.3 DBRS indicates that FEI's financial metrics are expected to remain within DBRS' "A" rating guidelines with the 8.75 percent ROE and 38.5 percent equity thickness. Please calculate the additional revenue requirement and rate impact as a result of the increase in ROE to 9.5 percent and the increase in equity thickness to 40 percent for FEI. Does FEI agree that it is not efficient to increase revenue requirement for a purpose (i.e., remain within DBRS' A rating) that is already served?

Response:

The additional FEI revenue requirement and rate impacts that would result from an increase in the ROE to 9.5 percent and an increase in the equity thickness to 40 percent are provided below.

Summary of Impacts for an Average Mainland Residential Customer Using 90 GJs and 9.50% ROE, 40.0% Equity Thickness[1]

Revenue Requirement $000s increase	$	21,520
Delivery Margin % increase		2.83%
Annual Bill Impact	$	15.79

Notes:
[1] - Compared to Compliance Filing of Annual Review of 2016 Rates which includes 8.75% ROE and 38.5% Equity Thickness

While FEI has provided the requested information on revenue requirement and rate impacts, the Fair Return Standard requires the utility's regulated rate of return to be established independently of the revenue requirement impacts. Binding judicial authorities have characterized as "absolute" the obligation to approve rates that afford the utility an opportunity to earn the fair return. In *British Columbia Electric Railway Co. v. Public Utilities Commission*, [1960] S.C.R. 837 at 848 (see also pp.856-857) Locke J. stated

> I do not consider that Question (1) can be answered by a simple affirmative or negative. The obligation to approve rates which will produce the fair return to which the utility has been found entitled is, in my opinion, absolute, which does not mean that the obligation of the Commission to have due regard to the protection of the public, as required by s. 16(1) (b), is not to be discharged. It is not a question of considering priorities between "the matters and things referred to in Clauses (a) and (b) of subsection (1) of s. 16". The Commission is directed by s. 16(1) (a) to consider all matters which it deems proper as affecting the rate but that consideration is to be given in the light of the fact that <u>the obligation to approve rates which will give a fair and reasonable return is absolute</u>. [Emphasis added.]

In the context of this question regarding credit ratings, the relevant question is whether or not FEI's request meets the financial integrity and capital attraction requirements.

B. FORTISBC ENERGY INC. BUSINESS RISK ASSESSMENT

16.0 Reference: Exhibit B-1, p. 14; Appendix C – FEI Business Risk Assessment, Section 2.2, Summary Assessment of Amalgamated FEI's Business Risk, pp. 3–4;

GCOC Stage 2 Decision dated March 25, 2014, p. 56

Energy supply risk

Table C-2 in Appendix C shows the amalgamated FEI's business risk as compared to the 2012 benchmark utility, including the "risk status change due to amalgamation alone." FEI views that all risk categories are the same post-amalgamation with the exception of higher security of supply.

On page 14 of its Application, FEI states:

> The addition of FEVI and FEW to FEI's service territory has slightly increased FEI's exposure to security of supply risk, as these two utilities are downstream of pre-amalgamated FEI on a radial system that crosses challenging terrain and the Strait of Georgia. As such, the overall energy supply risk is considered to be slightly higher than 2012 levels.

On page 56 of the GCOC Stage 2 Decision, the Commissions stated:

> The Commission Panel finds that there are additional supply interruption risks faced by FEVI and FEW when compared to the Benchmark but they are marginal. Therefore, the Panel places minimal weight on this factor.
>
> The Commission Panel agrees with BCPSO with respect to the likelihood of both of FEVI's submarine crossings being disabled concurrently. We acknowledge that there is a remote possibility but the probability is very low. The Panel acknowledges that both FEVI and FEW load centres are at the end of a radial line which results in some increased risk and FEW's lack of on-system storage. However, FEVI and FEW did not provide evidence to establish the level of probability related to such an occurrence or examples of where these types of issues proved to be a problem in other jurisdictions.

16.1 Given that the Commission placed minimal weight on the supply interruption risks, please discuss any other compelling reasons since March 2014 that the Commission should place a greater weight on the supply interruption risk.

Response:

As acknowledged by the Commission panel in the preamble above, both FEVI and FEW load centers are at the end of a radial line which results in some increased risk. This risk did not exist for pre-amalgamation FEI and is considered an incremental risk to FEI Amalco. In other words, FEI is not arguing for placing a greater weight on this risk but rather identifies that FEVI's and FEW's supply interruption risks have transitioned to FEI Amalco's supply interruption risk. FEI recognizes that the incremental supply interruption risks arising from amalgamation are modest for the reasons described on p.56 of Appendix C. Hence, FEI has identified only a "slight increase in overall business risk" (Application, p.3) associated with amalgamation.

16.2 Given that FEVI and FEW are likely to make up only a small portion of the overall FEI Amalco, is it fair to say that the incremental supply interruption risk is minimal? Please explain.

Response:

FEI agrees with the Commission Panel's findings in the preamble that there is additional supply interruption risk faced by former FEVI and FEW service territories but that this risk is marginal. Please also refer to the response to BCUC IR 1.16.1.

17.0 Reference: Exhibit B-1, Appendix B – Evidence of Mr. James Coyne, Appendix A, Proxy Group Assessment, pp. A16–A87; Appendix C – FEI Business Risk Assessment, Section 2.2, p. 4; Section 10, Regulatory Risk, pp. 73–75

Regulatory risk

On page 4 of Appendix C, FEI describes the main cause of regulatory uncertainty being the regulatory discretion in approving or denying a utility's applications. FEI further expands the regulatory uncertainty that 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.

FEI has assessed its overall regulatory risk as being similar to what it was in 2012, with the potential to be higher over the term of performance based ratemaking (PBR).

17.1 On page 74 of Appendix C, FEI states that risk is elevated during the PBR term (i.e., 2014-2019) as a materiality limit gives rise to the potential for denial of prudently incurred costs and increases the underlying risk to the Company. Please confirm that the materiality limit only applies to extraordinary events, like natural disasters.

Response:

Not confirmed. An "unforeseen event" is the correct nomenclature for the events that apply to the Z-factor mechanism, not "extraordinary events". The materiality threshold in the Z-factor mechanism as defined in the 2014 PBR Decision applies to unforeseen events that are caused by exogenous factors outside the control of a prudently operated utility and the cost or saving of which are clearly outside the base upon which the rates were originally derived. The specific wording from the PBR Decision has set criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment:

1. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;
2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;
3. The impact of the event was unforeseen;
4. The costs must be prudently incurred; and
5. The costs/savings related to each exogenous event must exceed the Commission defined materiality threshold.

The choice of word in this context is important because “extraordinary” events implies events that do not happen often while unforeseen events caused by exogenous factors may happen more frequently and include not only natural disasters but also incidents like man-made damages or judicial, legislative, administrative changes, orders or directions that create additional costs for the utility. For example, in FBC’s Annual Review for 2016 Rates, it has received Z-factor treatment of both wildfire damage and Mandatory Reliability Standard compliance costs.

In any case, the materiality threshold gives rise to the potential for denial of prudently incurred costs and increases the underlying risk to the Company, due to the potential for items falling below the threshold, which could be significant when considered on a cumulative basis. In addition, the other criteria when considered together can give rise to situations where, even when the materiality threshold is exceeded, recovery of prudently incurred costs could be denied.

As seen in Table C-2, FEI continues to rank regulatory risk as its highest risk area, as it had in the 2012 Stage 1 GCOC proceeding. On page 73, FEI states that regulatory oversight gives rise to the risk that the allowed return does not accord with the Fair Return Standard.

17.2 Does FEI agree that the in the absence of, or lack of, regulatory oversight could mean that FEI would, in the alternative, be facing market risk?

<u>Response:</u>

FEI notes that even as a regulated entity, FEI faces market risk in the context of competition for customers and throughput. While the regulator plays an important role in minimizing direct competition from a natural gas distribution competitor, other entities compete directly for the market against FEI.

Other things being equal, rate regulation directionally reduces a company’s market risk. However, this fact does not affect or change FEI’s risk ranking. FEI has evaluated its risk profile in light of the fact that it is, and will remain, a regulated entity. As a regulated entity, regulatory decisions can have the single largest impact on FEI’s ability to earn a fair return and recover its invested capital, and therefore, FEI has ranked regulatory risk as its highest risk area.

17.3 While FEI assesses the overall regulatory risk as being similar to what it was in 2012, please provide a list of recent examples (from 2012 to 2015) that FEI's rates were set at a level that did not provide FEI with an opportunity to earn its fair return.

Response:

Please refer to the response to CEC IR 1.17.2 for historical data on FEI's allowed and achieved ROE for 1995 to 2014. As can be seen in the table provided in that response, FEI has met or exceeded its allowed ROE for the majority of those years (exceptions are 1998 and 2010). Since FEVI and FEW were purchased by FEI's parent company, FEVI was unable to achieve its allowed ROE in 2003, 2010 and 2011 and FEW was unable to achieve its allowed ROE in 2003, 2004, 2010 and 2012.

In all years, as part of the forward looking rate setting regulation used in BC, FEI may earn more or less than the allowed ROE based on variations from forecasts. The fact that FEI is able to achieve its allowed ROE does not indicate, in and of itself, that the approved ROE is deemed sufficient, nor does it alleviate investors' concerns regarding the long-term regulatory risk caused by the uncertainty that is inherent in the nature of the regulatory framework.

On page 75 of Appendix C, FEI states that regulatory lag can present a risk for FEI's return on and of capital because it is necessary for the utility to conduct its operations based on interim rates with no assurance that the interim rate will be confirmed in the final decision.

17.4 In Appendix B, where the risk template for each proxy company is presented, interim rate is described as an item where it is normally requested by the utility and allowed or disallowed under specific circumstances by the regulator. Does this regulatory arrangement make interim rate a tool to mitigate risk as opposed to a factor contributing to risk?

Response:

Interim rates are a tool aimed at providing the regulator with greater flexibility in reviewing applications without compromising the "just and reasonable" standard. In the absence of a power to approve interim rates, regulators would generally have to ensure that regulatory processes did not extend into the test period for which rates were being set. Otherwise, the utility or customers would potentially be paying too much or too little between (e.g.) January 1 and the date the final decision could be implemented. Rates that are unreasonably high or unreasonably low during that period are not “just and reasonable”. Interim rates are thus beneficial to both utilities and their customers in that they allow for reasonable procedural timelines for complex regulatory applications.

The issue that FEI is identifying as a risk factor is not the existence of interim rates *per se*, but rather the length of time that the utility remains on interim rates before a final order is made. Inherent in interim rates is the prospect that they will be changed with retrospective effect back to the beginning of the test period. The longer interim rates remain in effect, the less certainty the utility has regarding its budgeting and spending for the test period as a whole. In other words, regulatory risk is associated with waiting long periods for a final rate order.

To illustrate this risk, consider a scenario where interim rates go into effect on January 1 and the final decision only comes in September of that year, i.e. 9 months into a one year test period. The utility will be operating during the 9 month period without any certainty that its budget will be supported by rates. The utility would have only three months (October-December) to adjust spending to account for any unfavourable variance between the interim and final rate order. In practice, this could be difficult in certain cases.

FEI has identified regulatory risk associated with lag as being unchanged relative to what existed in 2012. (See p.75 of Appendix C)

18.0 Reference: Exhibit B-1, Appendix C – FEI Business Risk Assessment, Section 9, Political Risk, p. 59; Section 9.4, Aboriginal Rights and Title, p. 71

Aboriginal rights

On page 59 of Appendix C, FEI describes that the Supreme Court of Canada decision in *Tsilhqot'in Nation v. British Columbia* introduced new uncertainties.

On page 72 of Appendix C, FEI takes the position that a risk of litigation in BC is greater than other areas in Canada, and greater than it was in 2012.

18.1 Please also describe the joint efforts between aboriginal groups and FortisBC Inc. in developing liquefied natural gas (LNG) and other projects in British Columbia since 2012. Please comment on how the joint efforts would lead to heightened or reduced uncertainties in Aboriginal rights.

<u>Response:</u>

The question refers to FortisBC Inc., but has been interpreted as a reference to FEI.

The most significant instance to date of FEI working in tandem with First Nations on an LNG project was in respect of the Mt. Hayes LNG facility, which predated 2012. A non-regulated affiliate of FEI had recently been in the early stages of exploring an LNG project on Tsawwassen First Nation (TFN) lands, but this cannot proceed at the present time as the TFN has determined not to pursue it. There have been no other LNG projects of a similar nature since 2012.

Most of FEI's business, including new investments in LNG facilities (e.g. Tilbury expansion) or pipeline to serve LNG facilities (e.g., the Eagle Mountain-Woodfibre pipeline project), takes place without involving First Nations as a co-proponent or co-owner. In such cases, FEI's interaction with First Nations arises in the context of ongoing engagement regarding particular initiatives, and agreements. These interactions are similar in character today as they were prior to 2012, but tend to be more intensive for larger projects. Some members of First Nation communities have opposed LNG developments and FEI's developments that support LNG. Some First Nation communities have also begun to require a higher degree of control over the projects' assessment process and overall project design (e.g Eagle-Mountain-Woodfibre Project, and the Squamish Nation's own parallel regulatory process). FEI has experienced a relative growth in the expectations from First Nations, as they pertain to the degree of engagement and breadth and depth of benefits agreements and/or MOUs, and it is believed that these heightened expectations are, in part, as a result of the *Tsilhqot'in* decision. As discussed in the response to BCUC IR 1.18.2, the decision has been interpreted differently by some First Nations and thus represents a new challenge for FEI.

FEI's efforts to engage First Nations on large projects tied to LNG development have served to mitigate, in part, increased business risk associated with undertaking specific capital expenditures in the LNG business and the *Tsilhqot'in* decision. They do not reduce FEI's overall business risk below 2012 levels.

FEI's risk assessment in Appendix C accounts for all of the above considerations.

18.2 Assuming that FEI is correct in its assumption that there would likely be future litigation on facilities and projects that are already constructed and in place on lands, subject to a declaration of Aboriginal title, is it also true that the Tsilhqot'in decision also gave certainty to the First Nations groups on what is required to prove that they have Aboriginal title to select pieces of property? Is it also true that this Supreme Court of Canada decision also gives government confirmation that they continue to possess substantial authority over resource development on Crown lands?

Response:

For clarity, FEI did not say that "there would likely be future litigation on facilities and projects that are already constructed and in place on lands…". FEI indicated that the intent of "passages" in the *Haida* and *Tsilhqot'in* decisions "will likely be the subject of future litigation and interpretation" (p.72, line 17). FEI's position is that the risk of challenges and litigation has, other things being equal, increased since 2012 as a result of the *Tsilhqot'in* decision.

The *Tsilhqot'in* decision clarified the test for proving aboriginal title and presented the first example of how that test would be applied. FEI's risk is unaffected by any "certainty to the First Nations groups on what is required to prove that they have Aboriginal title to select pieces of property". FEI's service territory is covered by many First Nations traditional territories, most of those traditional territories incorporate claims of Aboriginal title (often overlapping) and there is potential for future claims for aboriginal title. Although the Court limits the requirement for consent (discussed below) to after Aboriginal title has been proven, there is a passage in the decision that has been interpreted by First Nations as requiring something more than consultation prior to proof of title, under certain circumstances. The Court held (at para. 91): "Where a claim is particularly strong — for example, shortly before a court declaration of title — appropriate care must be taken to preserve the Aboriginal interest pending final resolution of the claim." Although this was put forward as an exception to a general rule, many First Nations perceive their claims for Aboriginal title to be "particularly strong".

The *Tsilhqot'in* decision requires that, where Aboriginal title has been proven, governments can only infringe with consent or by meeting a test for justification of infringement. That is, governments only possess authority over resource development to the extent that their actions either do not infringe aboriginal title or they can justify the action based on the test. There will be disagreements in specific cases about whether government actions are justified. Moreover, the implications of the test for existing facilities have been clouded by the Court's comments quoted in FEI's Business Risk Appendix C at p.72: "if the Crown begins a project without consent prior to Aboriginal title being established, it may be required to cancel the project upon establishment of the title if continuation of the project would be unjustifiably infringing." These comments have been interpreted broadly by First Nations as applying to pre-existing facilities.

19.0 Reference: Exhibit B-1, Appendix C –FEI Business Risk Assessment, Section 3, Business Profile, pp. 7–11

Business profile and throughput

According to FEI, the amalgamation of FEI, FEVI and FEW took place on December 31, 2014, and the phase-in period will be completed on January 1, 2018.

19.1 Has FEI carried out any studies related to the impact of postage stamp rate on the capture rate and customer growth in the former FEVI and FEW service areas as well as the effects of the rates would have on the former pre-amalgamation FEI service areas? If so, please describe the study's conclusions.

Response:

No, FEI has not carried out any studies in this area. As stated on page 45 of FEI's business risk Appendix, FEI believes that the full effects of amalgamation on FEVI's and FEW's capture rates will not be clear until after the three year phase-in to common delivery rates.

19.2 On page 9 of Appendix C, FEI states that in 2014, amalgamated FEI's normalized demand has experienced a modest decrease compared to the 2012 levels. Can this decrease be attributable to the one industrial customer as described in footnote 10?

Response:

The change in the total throughput level is a result of the changes in demand across all customer types, including industrial customers. The modest decline in 2014 relative to 2012 was seen in each of the three different rate classes. FEI confirms that part of the decrease in the industrial demand is due to the net change in demand from the industrial customer described in footnote 10.

19.3 Please provide the data in Figures C-3, C-4, C-5 and C-6 in tabular format.

Response:

The data used to produce Figures C-3, C-4, C-5 and C-6 in Appendix C is provided in tabular format below.

Figure C-3

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Throughput (in PJs)										
Total Throughput	**213**	**206**	**209**	**203**	**201**	**203**	**208**	**213**	**209**	**209**
Total Accounts	**885,709**	**899,452**	**916,343**	**929,116**	**937,263**	**946,576**	**953,943**	**942,869**	**953,287**	**964,853**

Figure C-4

	Before 1950	**1950-1975**	**1976-1985**	**1986-1995**	**1996-2005**	**2006 or later**
Natural gas	89.2%	90.6%	85.7%	89.4%	83.6%	66.8%
Electricity	9.6%	7.8%	12.1%	9.4%	13.0%	28.9%
Other	1.1%	1.6%	2.3%	1.2%	3.4%	4.2%

Figure C-5

	Before 1950	**1950-1975**	**1976-1985**	**1986-1995**	**1996-2005**	**2006 or later**
Natural gas	80.8%	79.9%	75.6%	82.9%	79.9%	56.2%
Electricity	20.8%	15.3%	20.0%	12.8%	16.2%	30.9%

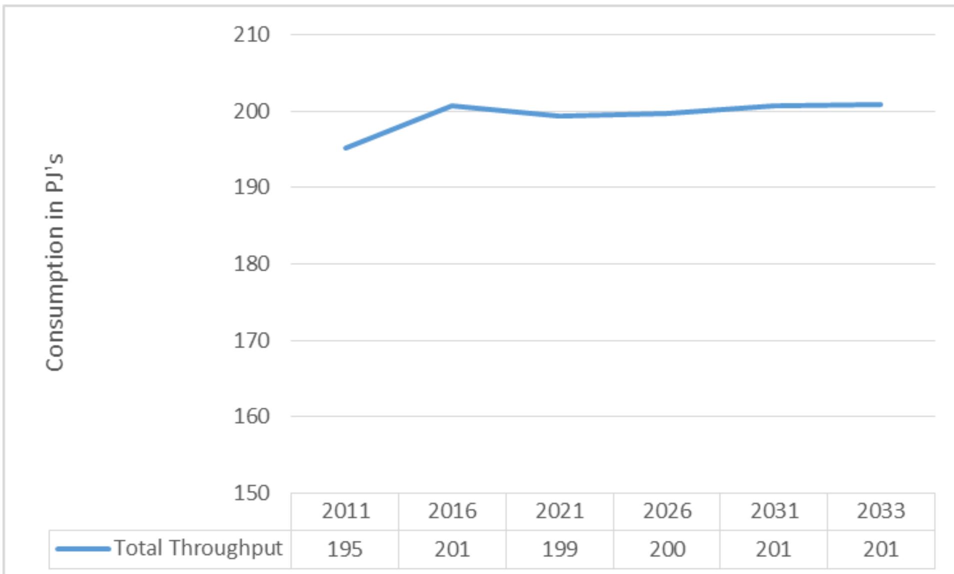
Figure C-6

Year	2011	2016	2021	2026	2031	2033
Consumption in PJs	74	73	70	70	69	69

19.4 Figure C-5 provides the outlook of amalgamated FEI residential throughput levels. Please replicate the chart, as well as providing information in tabular format, using total throughput.

Response:

FEI assumes that the reference in this question is to Figure C-6 in Appendix C. Therefore, FEI has provided the total throughput, which includes both non-bypass and bypass customers, in the same format as Figure C-6 in Appendix C of the Application, including the underlying data table at the bottom of the chart.



20.0 Reference: Exhibit B-1, Appendix C – FEI Business Risk Assessment, Section 3, Business Profile, Figure C-3, Figure C-6, pp. 10, 12; Section 6, Market Shifts Risk, pp. 45–50

Business profile and market shifts risk

On page 12 of Appendix C, FEI states:

> Similar to 2012, the trend in FEI's throughput level, particularly for the residential sector, is characterized by: (a) weak capture rates in the new construction market in the growing multi-family dwelling sector, and (b) declining use per customer from existing and new customers which is caused by factors such as smaller average dwelling size, higher capital costs for natural gas appliances versus electric appliances, changes in customers' preference and improvements in energy efficiency and conservation efforts supported by the policies of provincial and local governments.

Figure C-3 on page 10 of Appendix C shows the amalgamated FEI's total throughput (normalized throughput vs. customer accounts). Figure C-6 shows the outlook of amalgamated FEI residential throughput levels.

Figure C-27 on page 45 of Appendix C shows the amalgamated FEI's historical residential normalized use per customer (UPC) from 2005 through 2014. Figure C-33 on page 49 of Appendix C shows the amalgamated FEI's residential customer additions from 2005 to 2014. Figure C-34 on page 50 of Appendix C shows the amalgamated FEI's commercial customer additions from 2005 to 2014.

20.1 Please provide annual normalized throughput data from 2000-2015. Include the year over year change and discuss the annual changes from 2012 to 2015. For instance, is there evidence to show that the rate of decline in recent years (2015) is faster than in previous years (2012)?

<u>Response:</u>

Please note that data prior to 2004 cannot be provided on the amalgamated basis as this is prior to the acquisition of Centra Gas. 2015 is excluded as there is no year-end actual normalized data available at this time.

The annual actual normalized throughput data, including bypass customers, from 2004 to 2014 is provided below. There is no evidence of a steeper rate of decline throughout any sustained period of the data set. There is a consistent declining trend seen in the residential class which has been partially offset by increases in other classes, such as Industrial. The amount and the frequency of this offsetting increase from other rate classes such as industrial is inconsistent and there is no expectation that the increases in other classes are enough to offset the persistent declining trend that has been accelerated in recent years in the residential class.

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Throughput (in PJs)											
Total Throughput	**219**	**213**	**206**	**209**	**203**	**201**	**203**	**208**	**213**	**209**	**209**
year over year change		**-3%**	**-3%**	**1%**	**-3%**	**-1%**	**1%**	**2%**	**2%**	**-2%**	**0%**

20.2 Please provide the data and methodology to arrive at the throughput levels graph shown in Figure C-6. Why does the throughput level decline at an accelerated rate starting in 2016 through 2021?

Response:

The throughput levels graph shown in Figure C-6 is based on the 2014 LTRP reference case annual demand forecast. The residential demand forecast methodology and results received extensive review through the regulatory proceeding for the 2014 LTRP. A portion of that information is provided here in response to this request.

The LTRP reference forecast was built using the Company's 20-year account forecast, with new dwellings and floor space based on the account growth rates. Anticipated efficiency improvements, including known code changes and the natural replacement of equipment such as furnaces and hot water tanks, were incorporated in both existing buildings and new construction. Anticipated changes in the saturation and gas shares for specific end-uses were also incorporated.

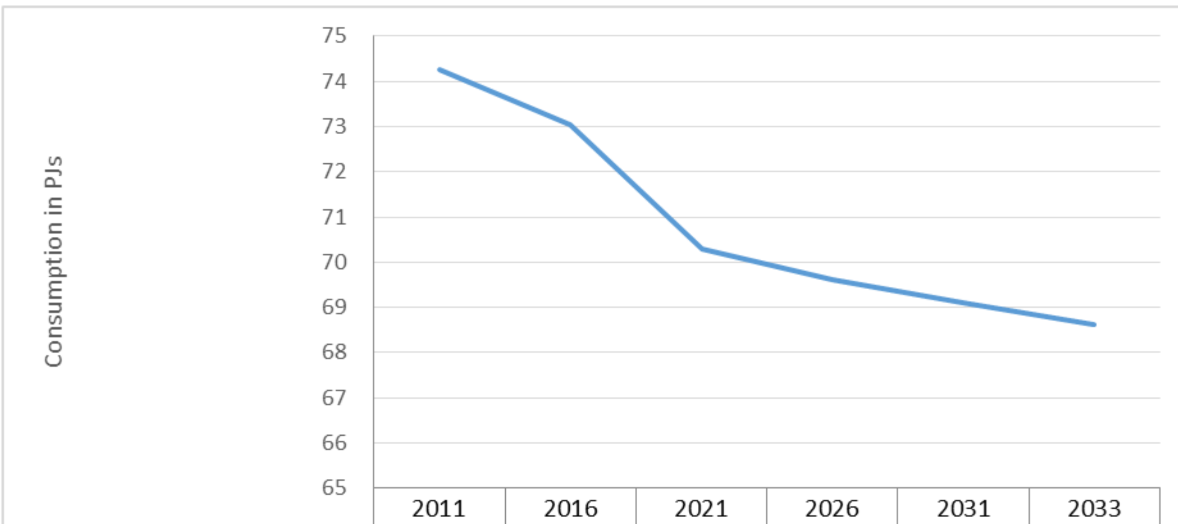
As the overall methodology is end use based, accounting for changes in the use of appliances in the residential class, the accelerated rate of decline in 2016 through 2021 is largely due to major changes in domestic hot water and space heating combined with slowed customer additions during the same time period.

BCUC IR 1.19.4 in the 2014 LTRP proceeding requested FEI to provide a table showing the assumptions and variables that underpin the reference case demand forecast. FEI responded that a full listing of all assumptions and variables would result in over 4,000 pages of information, but provided a sample table of assumptions and variables for residential domestic hot-water. The response to that IR is provided in Attachment 20.2 in order to help provide some of the data that makes up the reference case forecast for residential demand.

Further, BCUC IR 1.38.1 in the 2014 LTRP proceeding requested FEI to provide a table showing for each variable the value in the reference case and the value in the scenario analysis. The response to that IR, as applied to the residential demand forecast, is also provided in

Attachment 20.2, helping to explain how the reference case residential demand forecast was developed.

The cumulative changes over the 6 milestone years are, respectively, -2%,-4%,-1%,-1%,-1%. The historical rate of decline in 2014 relative to 2009 on a cumulative basis is approximately -2%, which is in line with the rate of decline in the LTRP forecast, with the exception of the 2016 to 2021 period where a steeper decline was forecast due to the aforementioned factors.



	2011	2016	2021	2026	2031	2033
Residential Throughput	74	73	70	70	69	69

20.3 With respect to residential (UPC) as shown in Figure C-27, please compare the rate of decline experienced between 2012 and 2015. For instance, compare the average rate of decline in the past five years from 2007-2012 and 2010-2015.

Response:

As shown in Figure C-27 and discussed on Page 45 of Appendix C, the rate of decline in residential annual use per customer from 2005 to 2014 is approximately 11 percent. The cumulative rate of decline from 2007 to 2012 was approximately 5 percent, or approximately 1 percent annually. The cumulative rate of decline from 2009 to 2014 was approximately 5.5 percent, or approximately 1.1 percent annually[13].

[13] Figure C-27 does not include 2015 information. FEI has instead used the period up to 2014 in this response.

These comparative periods are indicative of a continuing persistent decline in normalized residential use rates.

20.4 With respect to residential customer additions, Figure C-33 shows that net customer additions had been declining prior to 2012 and increasing since 2012. It also shows that the percentage of customer additions to total number of customers has rebounded since 2012. Does FEI agree that these observations lower market shift risk? Please explain.

Response:

No. The increase in the number of net residential customer additions since 2012 does not indicate a decline in market shift risk.

First, as noted on page 49, footnote 44 of Appendix C, in 2013 and 2014, FEI undertook an initiative to repatriate customers that had a meter and service line but who had stopped taking service from FEI. This resulted in an increased number of residential as well as commercial net customer additions in those years. This initiative primarily accounts for the increase in additions seen in 2013 and 2014. It is a short term impact that will not affect the longer term trend.

Furthermore, as demonstrated in Figure C-29, the new residential customers added to the system between 2011 and 2014 have lower use per customer (UPC) than existing customers which has a long-term impact on FEI's residential throughput. In other words, contrary to the suggestions in the question, a constant increase in number of residential customer additions is needed to keep the residential throughput, and therefore market shift risk related to it, at the current level.

Data related to the number of customer additions should not be considered in isolation. Despite the increase in number of customer additions since 2012, FEI has continued to experience declining residential UPC and has lost market share to electricity in space heating and water heating sectors as corroborated by BC Hydro's 2015 residential end-use survey.

20.4.1 Similarly, commercial customer additions in Figure C-34 show an increase from 2012 and appear to be approaching pre-recession levels in 2008. Does FEI agree that this observation lowers market shift risk?

Response:

No. The increase in number of commercial customer additions since 2012 does not indicate a decline in market shift risk.

First as noted on page 49, footnote 44 of Appendix C, in 2013 and 2014, FEI undertook an initiative to repatriate customers that had a meter and service line but who had stopped taking service from FEI. This resulted in an increased number of residential as well as commercial net customer additions. Commercial net customer additions are highly volatile and do not exhibit a clear trend.

Data related to the number of customer additions should not be considered on a stand-alone basis. Despite the increase in the number of customer additions since 2012, FEI's commercial UPC has slightly decreased since 2012.

21.0 Reference: Exhibit B-1, Appendix C – FEI Business Risk Assessment, Section 3, p. 13

New markets

On page 13 of Appendix C, FEI states that it is exploring possibilities such as expanding its LNG business for regional export markets, remote communities and power generation. For 2015, this mainly includes the LNG transported from FEI's Tilbury LNG Plant to the Yukon and Northwest Territories for power generation as an alternative to diesel-fuel, with a forecasted annual demand of 87 TJ in 2015.

21.1 Please provide a list of export markets for LNG exports that FEI is exploring. Please comment on the number of contracts that are imminent, e.g., supply agreement to Hawaii Electric.

Response:

FEI is exploring a number of regional export markets for the sale of LNG from the Tilbury facility. The markets under development include remote stationary power in Alaska, marine vessels operating in the Pacific Northwest trade, Hawaii Electric Company, Hawaii's gas utility and potentially working with trading and shipping companies acting as aggregators to ship LNG to Asian and South American markets.

These export markets under development are in addition to domestic markets that FEI will serve out of Phase 1A of the Tilbury expansion. These domestic markets include power generation for industrial and remote communities, on road trucking, marine markets (i.e. BC Ferries and Seaspan), mine haul trucks and locomotives.

FEI is in various stages of discussions depending on the customer but no contracts have been finalized or are imminent at this time.

21.2 The company evidence mentions the forecasted annual demand of 87 TJ in 2015 with respect to LNG sales to the Yukon and Northwest Territories for power generation. Is FEI referring to a new market that does not previously exist?

Response:

These markets were initiated for LNG prior to 2015 by FEI to replace diesel in power generation. In that sense these are not new markets; however FEI is looking to pursue additional similar opportunities if and where possible.

21.2.1 Based on the 2015 use per residential account, please describe 87 TJ in terms of new residential customers added to FEI. Please make explicit the assumptions used.

Response:

Based on FEI's Annual Review for 2015 Rates Compliance Filing[14], FEI's 2015 forecast Residential Use per Customer for 2015 is equal to 83.2 gigajoules[15] and the consumption for new residential customers is 68.3 GJ per year[16]. The addition of 87 TJ (87,000 gigajoules) is equal to 1,046 existing residential customers or 1,274 new residential customers[17].

FEI states that it expects the new initiatives and the investment in new infrastructure to serve the new initiatives would bring some benefits to existing customers but will not fundamentally change the core business of FEI.

21.3 In what ways will the existing customers benefit? Please quantify the benefits the FEI expects.

[14] Filed with the British Columbia Utilities Commission on June 30, 2015 pursuant to Orders G-86-15 and G-106-15.

[15] Section 11, Schedule 4, Line 2 Schedule 1 Residential 2015 Forecast Terajoules = 73,067.8. Section 11, Schedule 7, Line 3 Schedule 1 Residential Average Number of Customers = 878,512. 2015 Forecast Use per Customer -73,067,800 gigajoules/878,812 = 83.2 gigajoules and average for all existing customers.

[16] Section 4, page 51, FEI 2015 MX Text Application.

[17] 87,000 gigajoules / 83.2 gigajoules = 1,046 existing residential customers; 87,000 gigajoules / 68.3 gigajoules = 1,274 new residential customers

Response:

The means by which existing customers will benefit from the new large industrial volumes served under Rate Schedule 50 (RS 50) is that the rates charged to RS 50 customers will exceed the incremental costs of the infrastructure built to serve them. The RS 50 rates are designed to recover the incremental cost of service of the system upgrades necessitated by the RS 50 customer load plus a minimum additional contribution of $0.10/GJ[18]. The RS 50 rate is also subject to a Rate Floor of $0.55 per GJ[19]. If the calculated rate, including the $0.10/GJ System Contribution (as inflated), is less than $0.55 per GJ, the RS 50 rate remains at $0.55 per GJ, meaning that the net contribution to benefit existing customers will be greater than $0.10 / GJ if the Rate Floor is in effect. The aggregate net benefit to existing customers is dependent on the total RS 50 demand and the particular customers that are added. For illustrative purposes, the potential initial customers for RS 50 are projected to have demand in the range of 120 PJ to 150 PJ per year, suggesting a minimum net contribution of $12 million to $15 million per year (subject to FEI rate increases as described in footnote 18) , if those projects go ahead as planned.

21.4 If the investment in new infrastructure was carried out and the new initiatives were below expectations, to what extent would the ratepayers be harmed?

Response:

As described in the response to BCUC IR 1.21.3, the RS 50 tariff is designed to provide net benefits to other ratepayers. In addition, there are a number of safeguards in the RS 50 tariff which limit the possibility of harm to other ratepayers. Customers wishing to take service under RS 50 must sign up for a contract term of at least 15 years and for firm service at a demand level of 45 TJ/day or more. The RS 50 charges are on a take-or-pay basis and RS 50 customers are subject to security requirements that will help minimize potential negative impacts of customer default. In addition FEI will construct only the system upgrades that are necessary to meet the contracted demand of RS 50 customers while maintaining safe and reliable service levels for other natural gas customers. The cost of service of these RS 50-driven system upgrades will be recovered in the rates of RS 50 customers.

---

[18] The minimum contribution is called the “System Contribution” in the RS 50 Table of Charges. It is set at $0.10 per GJ in the initial period of RS 50 service and increases each year thereafter by FEI’s general rate increases applicable to non-bypass customers (subject to a minimum increase of 0% and a maximum increase of 3%).

[19] The RS 50 Rate Floor is $0.55 / GJ for aggregate RS 50 customer demand less than 200 PJ / year. The Rate Floor decreases to $0.50 / GJ if the aggregate RS 50 demand is between 200 PJ / year and 400 PJ / year, and to $0.45 / GJ is aggregate RS 50 demand exceeds 400 PJ / year.

21.5 If the new initiatives and new infrastructure are not in placed to increase throughput, is it true that FEI would still recover its future return on capital and return of capital?

Response:

There is no guarantee that FEI will be able to recover its future return on and of its invested capital, with or without these initiatives. All of the risk factors identified in the Business Risk Appendix can affect FEI's ability to recover its future return on and of capital. Declining throughput impacts customer delivery rates and increases FEI's business risk. Although, all else equal, the revenues from new initiatives have the potential to offset effects of declining throughput and therefore provide mitigation of the increases in FEI's business risk, they do not reduce FEI's business risk in absolute terms.

22.0 Reference: Exhibit B-1, Appendix C – FEI Business Risk Assessment, Section 4, Economic Conditions, Table C-5, p. 15

Economic indicators

On page 15 of Appendix C, FEI states that the current Canadian economic environment continues to be dominated by uncertainty. It summarizes the changes in leading economic indicators for four jurisdictions across Canada in Table C-5. FEI also concludes that the risks related to economic conditions today are similar to 2012.

22.1 Please expand Table C-8 by extending the years to start in 2004.

Response:

The TD Economics report does not include actual data for years prior to 2012, therefore the historical data has been retrieved from the Statistics Canada website.

Real GDP growth (at market prices - Chained $2007)

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BC	C$2007 MM	175571	184267	192385	198325	199768	194987	200324	206360	211427	215901	222868	N/A
	% change	3.9%	5.0%	4.4%	3.1%	0.7%	-2.4%	2.7%	3.0%	2.5%	2.1%	3.2%	2.5%
Alberta	C$2007 MM	231198	241330	256614	260964	265165	250510	262720	279655	290544	305353	320113	N/A
	% change	5.5%	4.4%	6.3%	1.7%	1.6%	-5.5%	4.9%	6.4%	3.9%	5.1%	4.8%	-1.4%
Ontario	C$2007 MM	567600	585843	596797	601735	601723	582904	600131	614606	622717	631068	648352	N/A
	% change	2.8%	3.2%	1.9%	0.8%	0.0%	-3.1%	3.0%	2.4%	1.3%	1.3%	2.7%	2%
Quebec	C$2007 MM	290941	295263	298803	306029	311945	309359	315708	321647	324993	329038	334103	N/A
	% change	2.5%	1.5%	1.2%	2.4%	1.9%	-0.8%	2.1%	1.9%	1.0%	1.2%	1.5%	1.7%

Source: CANSIM (Table 384-0038),

Note:

- TD Economics forecasts do not include the dollar amount.
- StatsCAN indicated that Canada totals in the provincial and territorial gross domestic product by income and by expenditure accounts (PTEA) do not correspond to the national gross domestic product by income and by expenditure accounts (IEA) estimates at certain times of the year. The IEA's annual revisions, released each spring, result in a discrepancy between the estimates.

Unemployment Rate

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
BC	7.2	5.9	4.8	4.3	4.6	7.7	7.6	7.5	6.8	6.6	6.1	5.9	5.9
Alberta	4.7	4	3.5	3.5	3.6	6.5	6.6	5.4	4.6	4.6	4.7	6	6.6
Ontario	6.8	6.6	6.3	6.4	6.6	9.1	8.7	7.9	7.9	7.6	7.3	6.7	6.7
Quebec	8.5	8.2	8.1	7.3	7.2	8.6	8	7.9	7.7	7.6	7.7	7.6	7.5

Source: CANSIM (Table 282-0002) and TD Economics October 2015 Provincial Forecast

Housing Starts

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
BC	32925	34667	36443	39195	34321	16077	26479	26400	27465	27054	28356	32500	28700
Alberta	36270	40847	48962	48336	29164	20298	27088	25704	33396	36011	40590	36300	32800
Ontario	85114	78795	73417	68123	75076	50370	60433	67821	76742	61085	59134	63500	58500
Quebec	58448	50910	47877	48553	47901	43403	51363	48387	47367	37758	38810	36200	31000

Source: CANSIM (Table 027-0008) and TD Economics October 2015 Provincial Forecast

22.2 Please include the following indicators in the table: (a) BC business bankruptcies; and (b) Canada real gross domestic product (GDP) growth.

Response:

Please find the requested information in the tables below:

(a) Business Bankruptcy Rate in selected Canadian provinces: The TD Economics report did not include any information on Bankruptcy rates. The provincial bankruptcy rates were retrieved from Industry Canada, Office of the Superintendent of Bankruptcy Canada.

Year	BC	Alberta	Ontario	Quebec
2014	0.5	0.3	0.8	3.1
2013	0.5	0.4	1.0	3.3
2012	0.5	0.7	1.2	3.1
2011	0.5	0.8	1.4	3.2
2010	0.6	1.1	1.8	3.3
2009	1.1	1.2	2.6	4.1
2008	1.2	1.3	2.7	4.6
2007	1.3	1.4	2.9	4.2
2006	1.7	2.1	3.1	3.8
2005	2.4	3.9	3.3	3.7

Source: Industry Canada, https://www.ic.gc.ca/eic/site/bsf-osb.nsf/eng/br01821.html#three

Canada Real GDP growth: The requested information is available in Exhibit JMC-2 of Mr.Coyne's evidence.

23.0 Reference: Exhibit B-1, Appendix C – FEI Business Risk Assessment, Section 4, Economic Conditions, pp. 15–16;

Appendix A, Section 3A – Debt Analyst Reports, BMO Capital Markets report for FEI

Economic conditions

On page 15 of Appendix C, FEI in Table C-5 provides the economic indicators for British Columbia, Alberta, Ontario and Quebec from 2012 to 2016. On page 16 of Appendix C, FEI states:

> 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.

In Section 3A – Debt Analyst Reports of Appendix A, the BMO Capital Markets analyst states:

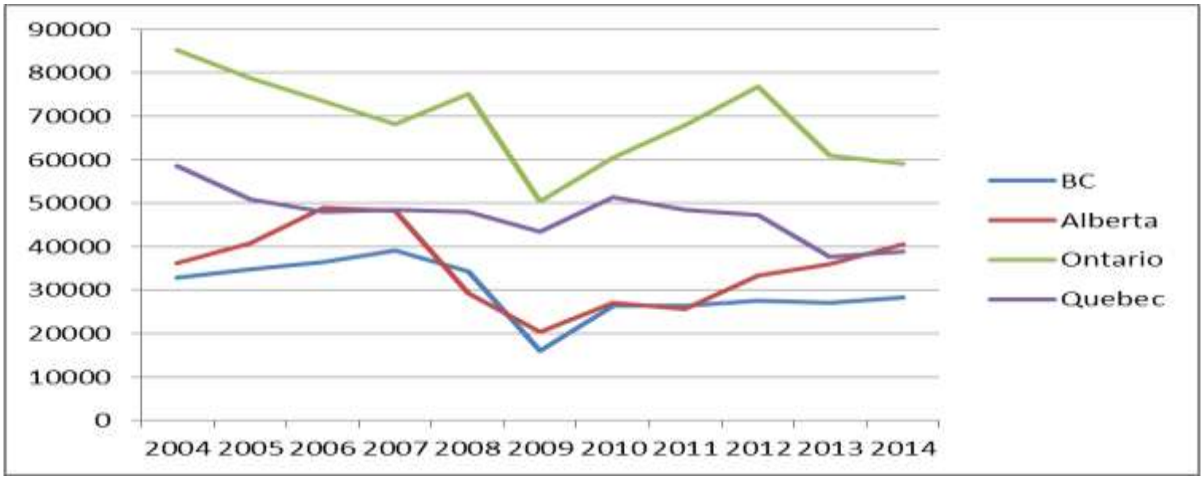
> An extended decline in economic conditions would be expected to reduce demand for energy over time. Energy sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices and housing starts.

23.1 Although BC housing starts are lowest among all four provinces, would FEI agree that the housing starts trend in BC remains steady when compared to all four provinces based on the data provided in Table C-5? Is a trend not more of an important indicator than the housing starts numbers since those numbers are a function of population size?

Response:

FEI believes that both the number of housing starts and any existing trend can be valuable for analysis. However, as demonstrated in the figure below, it is hard to find any definite trend in the number of housing starts. The annual percentage change in the number of housing starts is volatile and it is hard to forecast, as evidenced by changes in quarterly forecasts published by banks and other relevant institutions.

Nevertheless, FEI agrees that historical housing starts data in Quebec and BC are more stable than Ontario and Alberta.



23.2 By way of comparison, BC's GDP and unemployment rate is more favourable in BC than Ontario and Quebec. Does FEI agree that these favourable economic indicators benefit BC's utilities in the form of increased energy demand? Please discuss.

Response:

No. An increase in economic activities in BC does not necessarily lead to a significant increase in natural gas demand in FEI's service territory. BC has limited industrial demand in comparison to Quebec, Ontario or Alberta and BC's industries are less dependent on fossil fuels than these provinces. Much of BC's GDP is driven by housing construction and port activities which do not have the same energy intensity requirements from gas utilities as heavy manufacturing applications seen in other provinces. In contrast, Ontario's and Quebec's industries are more energy-intensive which means an equal percentage increase in Ontario's or Quebec's GDP may result in higher energy demand than BC.

BC is actively seeking to reduce emissions as evidenced by the Draft BC Climate Leadership Plan. In addition to the reduced load seen from energy efficiency in existing buildings, new buildings may require even stricter codes with respect to building design which may have the effect of making gas less competitive as a fuel source. Any future increases in carbon tax will force downward pressure on the use of natural gas and therefore increase business risk. The effect of these policies may outweigh any impact from an increase in GDP with respect to the use of gas.

FEI also notes that the 2015 and 2016 forecasts for Real GDP growth and unemployment rates in BC and Ontario are relatively similar.

24.0 Reference: Exhibit B-1, Appendix C – FEI Business Risk assessment, Section 5.1.2, Electricity Prices, Figure C-12, p. 23

Natural gas prices vs. electricity prices

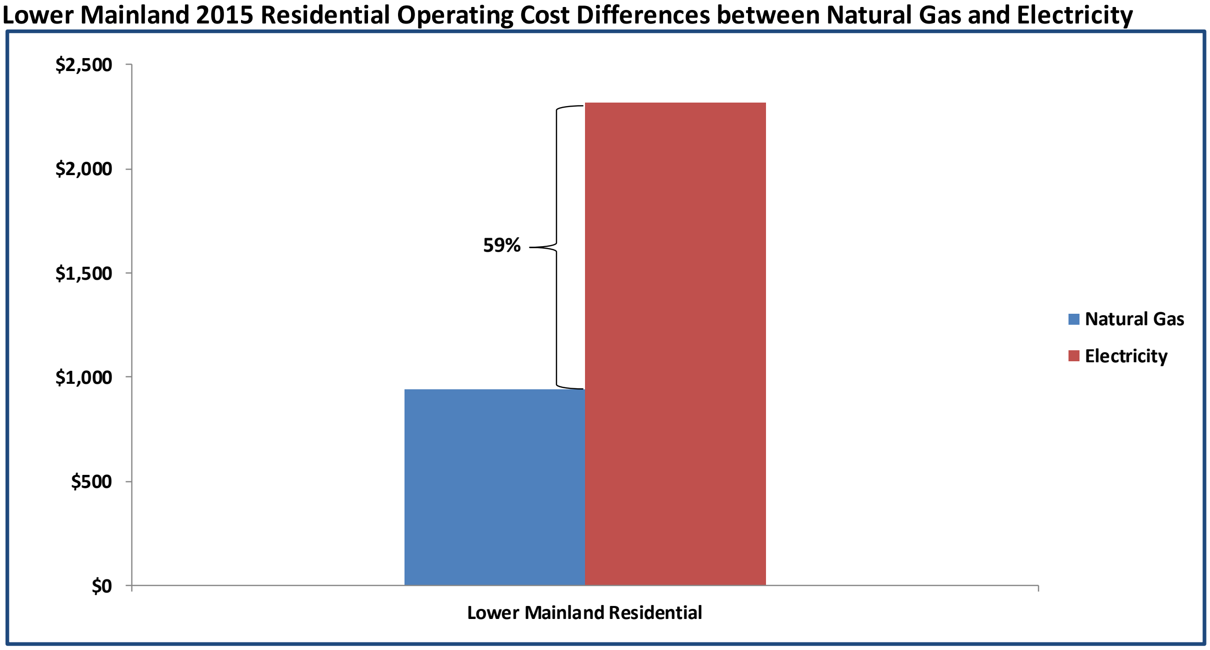
Figure C-12 shows the extent to which residential electricity rates differ from province to province, with major city represented.

24.1 Please provide a similar chart showing lower mainland residential customer operating cost differences between natural gas and electricity for the years 2000, 2005, 2009, and all years between 2012 and 2015.

<u>Response:</u>

Please refer to the charts below.

Lower Mainland 2015 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 BC Hydro in effect April 1, 2015

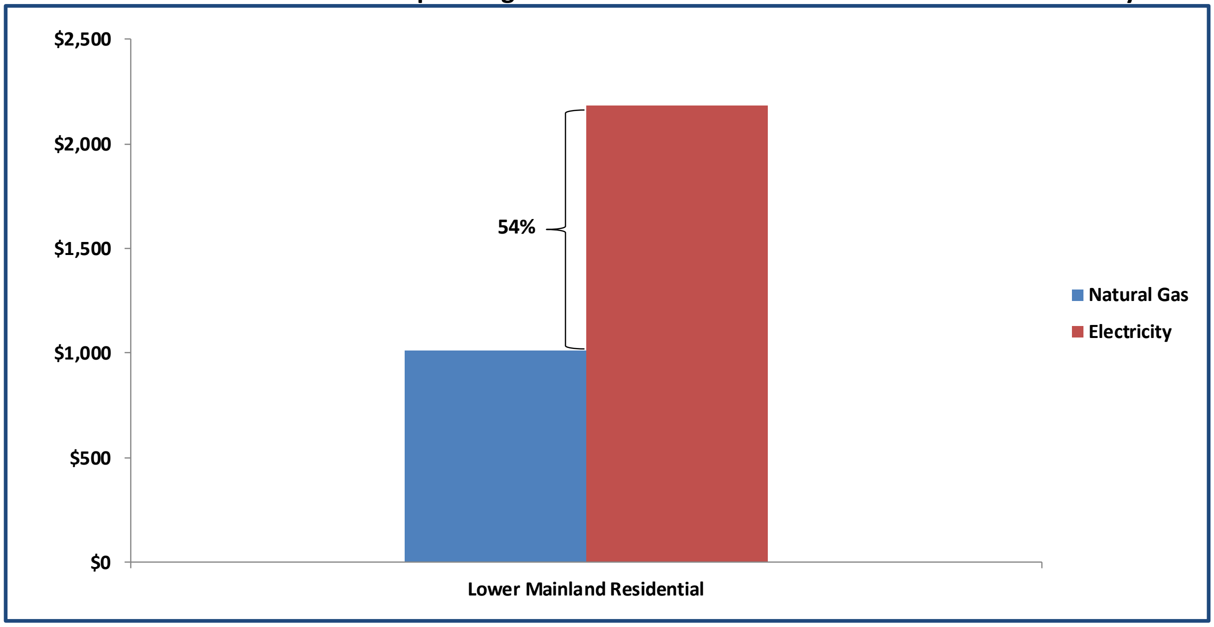
FEI Mainland residential rates are as at June 1, 2015

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 an annual use rate of 90 GJs

All bills are exclusive of applicable franchise fees and taxes (with the exception of the BC Carbon Tax for FEI)

Lower Mainland 2014 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 BC Hydro in effect April 1, 2014

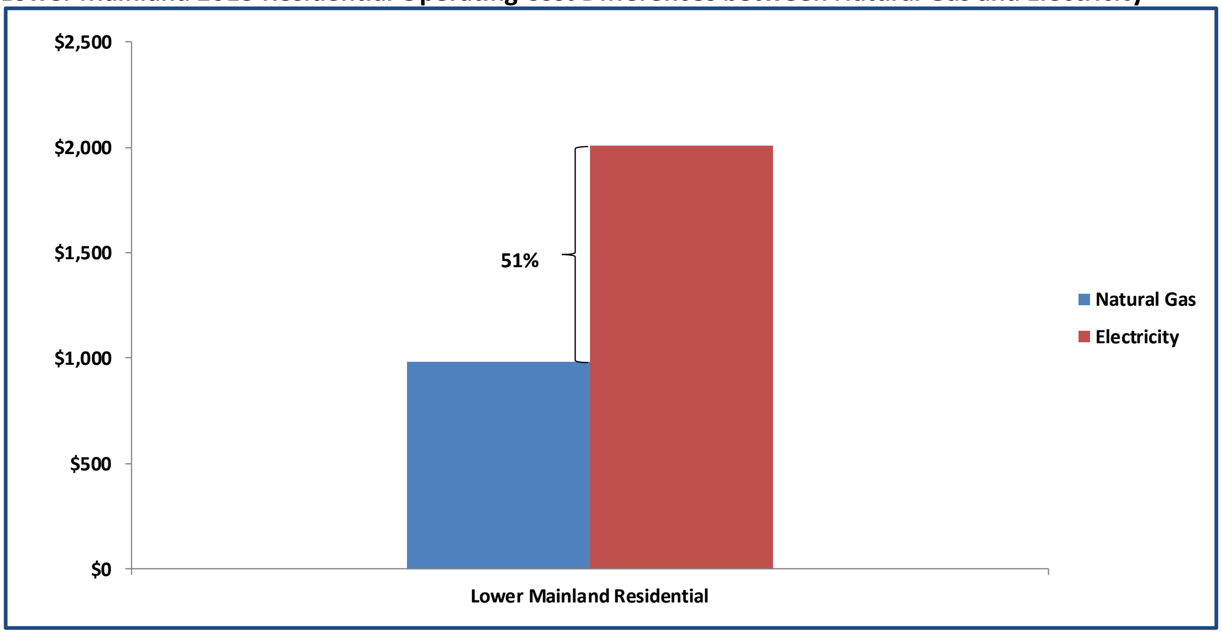
FEI Lower Mainland residential rates are as at January 1, 2014

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 an annual use rate of 90 GJs

All bills are exclusive of applicable franchise fees and taxes (with the exception of the BC Carbon Tax for FEI)

Lower Mainland 2013 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 BC Hydro in effect April 1, 2013

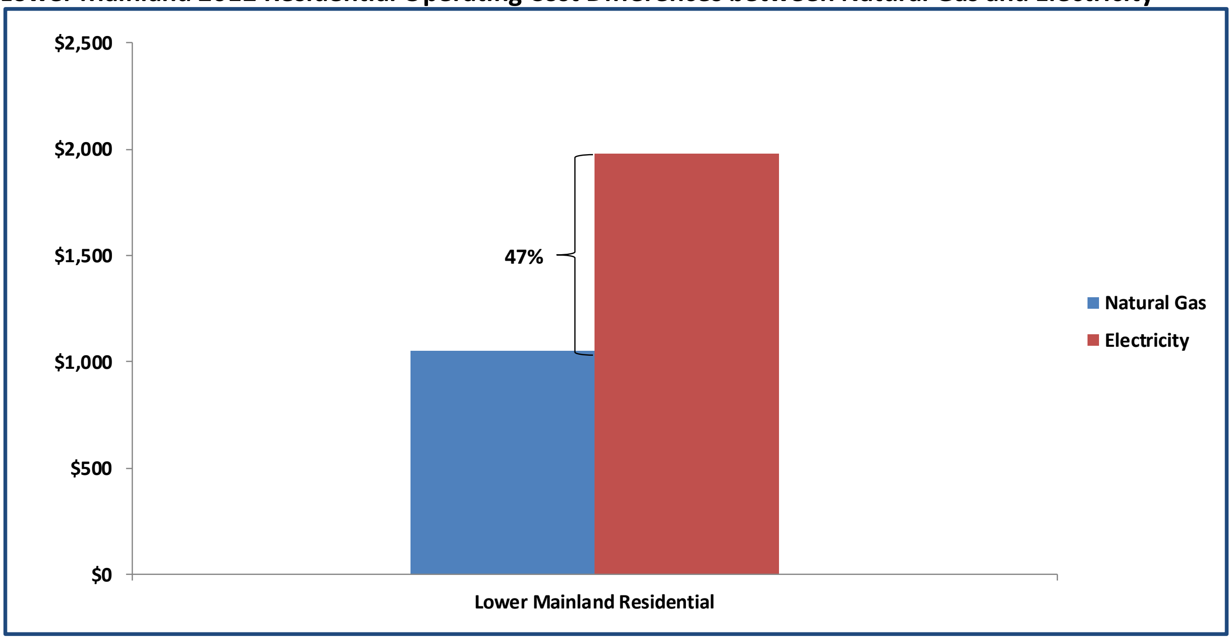
FEI Lower Mainland residential rates are as at January 1, 2013

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 an annual use rate of 90 GJs

1 All bills are exclusive of applicable franchise fees and taxes (with the exception of the BC Carbon Tax for FEI)

Lower Mainland 2012 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 BC Hydro in effect April 1, 2012

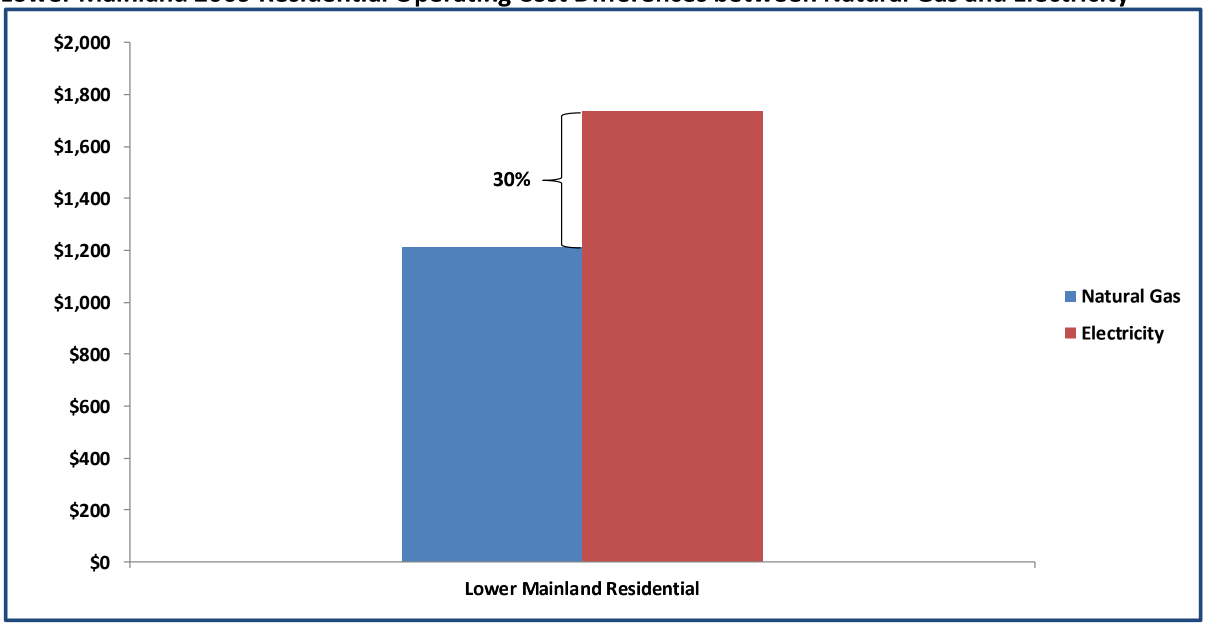
FEI Lower Mainland residential rates are as at January 1, 2012

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 an annual use rate of 90 GJs

All bills are exclusive of applicable franchise fees and taxes (with the exception of the BC Carbon Tax for FEI)

Lower Mainland 2009 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 BC Hydro in effect April 1, 2009

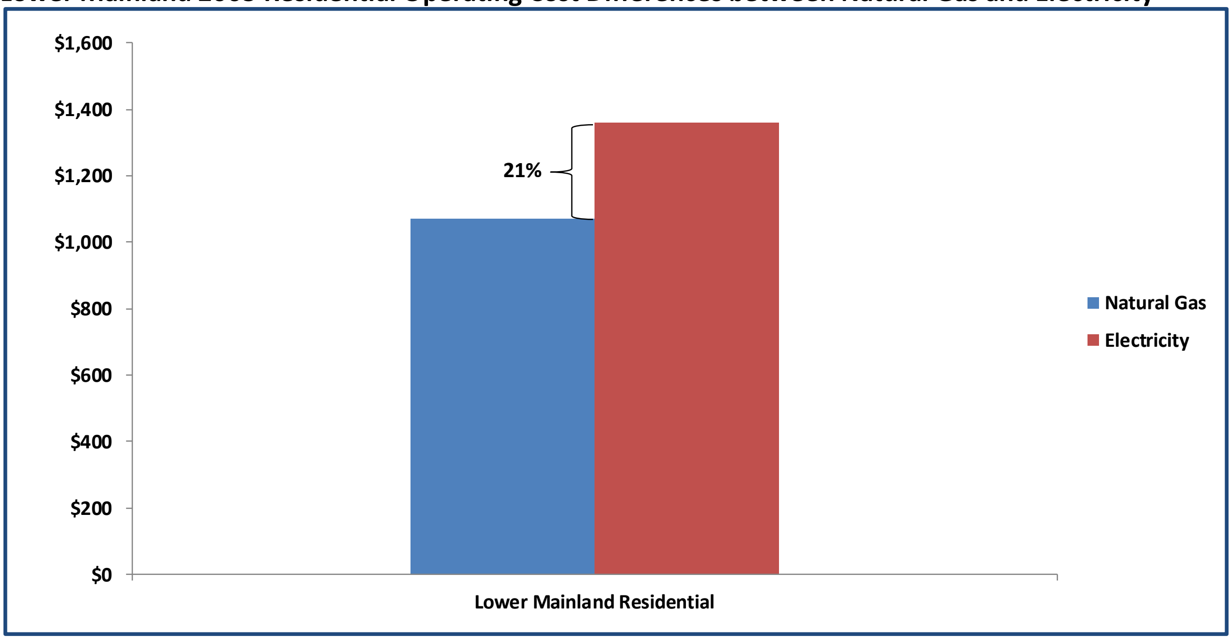
FEI Lower Mainland residential rates are as at January 1, 2009

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 an annual use rate of 90 GJs

All bills are exclusive of applicable franchise fees and taxes (with the exception of the BC Carbon Tax for FEI)

Lower Mainland 2005 Residential Operating Cost Differences between Natural Gas and Electricity



Assumptions:

BC Hydro rates effective April 1, 2004

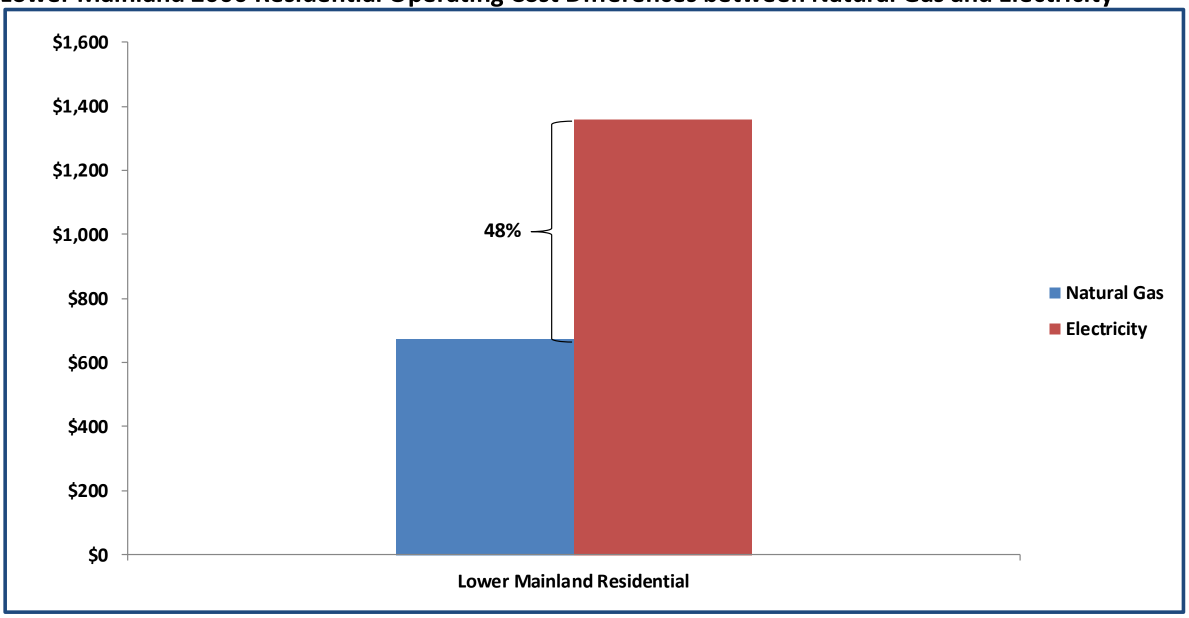
FEI Lower Mainland residential rates are as at January 1, 2005

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 an annual use rate of 90 GJs

All bills are exclusive of applicable franchise fees and taxes

Lower Mainland 2000 Residential Operating Cost Differences between Natural Gas and Electricity



Assumptions:

BC Hydro rates effective April 1, 1994

FEI Lower Mainland residential rates are as at January 1, 2000

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 an annual use rate of 90 GJs

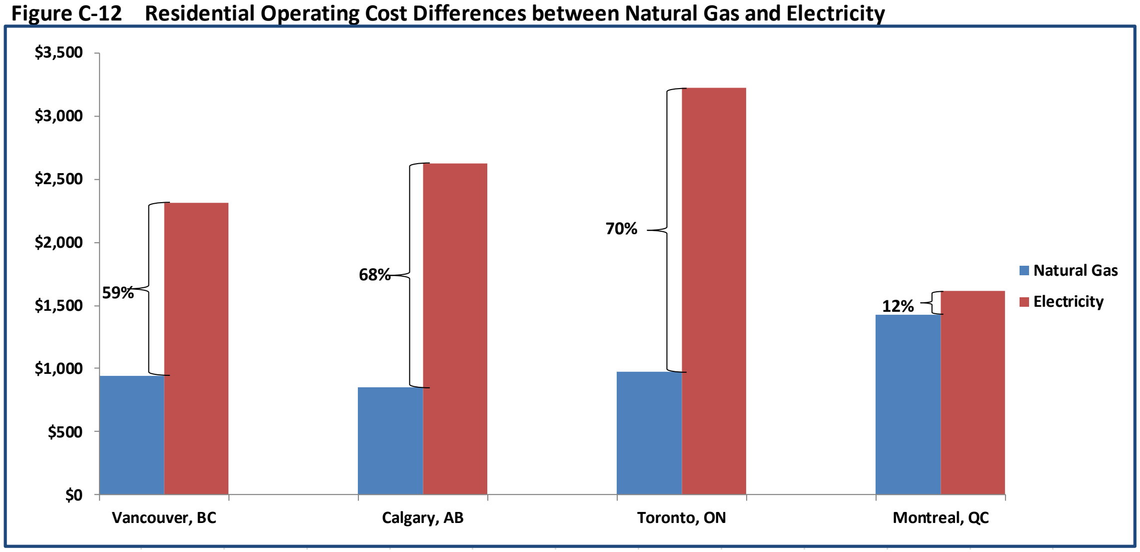
All bills are exclusive of applicable franchise fees and taxes

24.1.1 Please provide the corresponding data to support Figure C-12.

<u>Response:</u>

In responding to this question, FEI has identified an error in the Toronto, ON and Montreal, QC columns. The updated Figure-C-12 is provided below.

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 as at June 1, 2015 with the exception of Toronto which is 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 an annual use rate of 90 GJs

All bills are exclusive of applicable franchise fees and taxes (with the exception of the BC Carbon Tax for Vancouver, BC)

Please refer to Attachment 24.1.1 which provides the corresponding data to support the updated Figure C-12.

24.1.2 Please compare and discuss any trends observed in the operating cost differential from 2012 to 2015.

Response:

From 2012 to 2015, the operating cost differential between natural gas and electricity in British Columbia has improved from 45% in 2012[20] to 59% in 2015.

As stated in the Application[21]:

> *"In general, with recent increases in electricity prices, the current price competitiveness of natural gas has marginally improved, other things being equal. However, as discussed*

---

[20] 2012 Generic Cost of Capital Proceeding; Appendix H, Business Risk, Section 5.1 Commodity Price, Figure 12 Residential Operating Cost Differences between Natural Gas and Electricity, page 20.

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

> *in the Market Shift Risk and Political Risk sections, the improved price competitiveness of natural gas continues to be muted by non-price factors."*

That is, any improvement in price competiveness between natural gas and electricity is countered by other factors explained in the Application. These other factors include, for example, a higher capital cost differential for natural gas appliances (as presented on page 34 of Appendix C), mandatory connection provisions being contemplated or applied in certain municipalities (either through rezoning requirements or bylaw) or updates to building codes that limit FEI's ability to attract or retain customers (as explained in the political risks section of Appendix C). If a potential FEI customer cannot choose natural gas due to a government policy or a local government green initiative, then the price competitiveness of natural gas with electricity becomes irrelevant.

25.0 Reference: Exhibit B-1, Appendix C – FEI Business Risk Assessment, Section 5.3, Table C-6, p. 33; Section 6.2, Perception of Energy, Figure C-24, p. 42; Section 9.2, Provincial GHG Emissions Reductions and Local Government Initiatives, pp. 64–69

Upfront and installation costs

FEI analyzed the price competitiveness of natural gas by considering the upfront capital cost differences between natural gas and electricity end-use applications (space heating and water heating). The comparison is shown in Table C-6.

25.1 Please provide the data for Figures C-20, C-21, C-22 and C-23 in tabular format.

Response:

Please refer to the fully functional spreadsheet provided in Attachment 25.1.

On pages 64 to 69, FEI provides a description of local governments' recent steps to promote moving away from natural gas to other energy sources. FEI describes in Figure C-24 that there are barriers such as the high capital costs of adoption of alternative energy services.

25.2 Local government mandatory connections clause aside, has FEI undertaken any analysis of the capital cost differences between natural gas and alternative energy sources?

Response:

FEI has undertaken an analysis of rate and capital cost differences between natural gas and alternative energy sources for its intervention in the Creative Energy application. FEI filed evidence that compared the cost of heat delivered by an on site gas boiler solution to Creative Energy's district energy system for the Northeast False Creek area in Vancouver. The costing analysis (which included capital, operating, delivery and gas commodity costs) showed that on-site boilers with natural gas service from FEI was a more cost effective option to Creative Energy's proposed district energy system. The analysis is ultimately a situation specific exercise and does not lend itself to broad generalizations. An evaluation of alternatives will vary according to the specific situation (for example, e.g. building type and consumption) and given the vast array of equipment, age of equipment, efficiency of the equipment and potential usage of the equipment.

New energy systems (including district energy systems and the natural gas system on Vancouver Island) are capital intensive and in early start-up may not be able to compete with natural gas or electricity rates supplied by mature utilities. To remove this natural barrier to entry, regulators and municipalities promote a particular rate-setting mechanism, sometimes referred to as a market-based approach, in which rates are kept at an artificially lower level than the actual cost of service for the utility or even lower than the rates of other energy sources to promote the utility's growth. This approach is used by privately-owned as well as municipality-owned utilities in BC as explained in the City of Surrey Rate Setting Policy Document for Surrey City Energy (SCE) district energy project[22]:

> *"In the short term, as the DE system is maturing, SCE rates will not necessarily fully cover the debt servicing and operating costs of the system; however, the rate structure will allow for the recapturing of the early years deficits while remaining competitive with the costs that customers would incur if they were using other thermal energy options that are available in the market, such as electricity and natural gas".*

For the City of Surrey SCE project, BC Hydro's residential electricity rate was considered as a suitable benchmark against which SCE rates should be compared and SCE's objective was set for its rates to not exceed this benchmark for the first three years. Nevertheless, SCE's rate-setting document stated that its rates will also be compared with natural gas rates:

> *"While the BC Hydro rate is a suitable benchmark based on equivalence of service and customer understanding, rate comparisons will not be limited to BC Hydro. SCE rates will also be compared against the long-term capital and operating costs of natural gas as well as other lower mainland."*

This approach has also been applied to the SFU UniverCity District Energy system and River District Energy located in southeast Vancouver as well as the City of Vancouver's DE utility that services Southeast False Creek.

Furthermore, any capital cost difference between natural gas and alternative energy projects can be reduced due to the available subsidies for alternative energy projects. These alternative energy subsidies include: the Province of BC Provincial Sales tax exemptions on renewable energy equipment, the SolarBC institutional incentive funded by the Government of BC, the BC Clean Energy Fund, the Natural Resources Canada ecoENERGY Innovation initiative and the ecoENERGY for Renewable Power program. For example the COV's municipal owned utility, Southeast False Creek, received an external grant from senior levels of government of approximately $9 million.

Non-price considerations can, and often do, have a greater impact on energy decisions.

[22] https://www.surrey.ca/bylawsandcouncillibrary/CR_2013-R246.pdf.

26.0 Reference: Exhibit B-1, Appendix C – FEI Business Risk Assessment, Section 2.2, Summary Assessment of Amalgamated FEI's Business Risk, p. 3; Section 5.3, Upfront and Installation Costs, pp. 35, 37;

GCOC Stage 2 Decision dated March 25, 2014, pp. 53–54

Energy price risk – price competitiveness

In Table C-2 of Appendix C, FEI submits that the upfront and installation costs are the same for "total risk status since 2012" and the "risk status change due to amalgamation alone." The upfront and installation costs relate to the price competitiveness between natural gas and electricity.

Figure C-20 on page 35 of Appendix C shows the FEI Mainland service territory space heating burner tip rate vs. electric equivalents. Figure C-22 on page 37 of Appendix C shows the FEI Mainland service territory water heating burner tip and capital cost vs. electric equivalents.

On pages 53 and 54 of the GCOC Stage 2 Decision, the Commissions stated:

> [T]he Panel notes that in most cases, a builder must consider installation costs as they relate to the construction costs and they must weigh the cost of options against customer requirements. Therefore, the cost of energy is separate and combining the capitalized cost with the energy cost clouds the issue and is inappropriate. Eliminating capitalized costs from the cost of natural gas results in both FEW and FEVI rates being substantially lower vis-à-vis electricity Tier 2 rates. The question then becomes one of magnitude and the Commission Panel considers that while FEI holds an advantage in differential, the costs of energy in FEVI and FEW are still favourable.
>
> **The Commission Panel finds that FEVI and FEW face some additional risk due to differences in rates vis-à-vis electricity compared to FEI. The Panel also finds that natural gas rates are likely to continue to maintain a competitive advantage over electricity and therefore places minimal weight on this factor.**

26.1 Based on Figures C-20 and C-22 of Appendix C, it appears that the natural gas price advantage over electricity rates has been growing since July 2014 in both space and water heating. That is, the Mainland burner tip rate has been trending down while step 1 and 2 electricity rates are trending up. In light of the Commission's determination in the GCOC Stage 2 Decision that "the cost of energy is separate and combining the capitalized cost with the energy cost clouds the issue and is inappropriate", does FEI agree that the price differential between natural gas and electricity is growing, and that the price advantage in natural gas is becoming more favourable?

Response:

Please refer to the response to BCUC IR 1.24.1.2.

27.0 Reference: Exhibit B-1, Appendix C – FEI Business Risk Assessment, Section 5, Energy Price Risk, pp. 28–29, 32; Appendix B – Evidence of Mr. James M. Coyne, p. 78; Exhibit A2-1, FEI Price Risk Management Workshop Summary Report dated October 27, 2015

Energy price risk – commodity price volatility

On page 32 of Appendix C, FEI states: "FEI assesses the risk associated with market price volatility to be higher than 2012 and significantly higher than the Commission's expectations in 2012."

On page 78 of Appendix B, Mr. Coyne states:

> 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.

Figure 9 on page 68 of Appendix B shows the 45-day rolling average volatility (measured by standard deviation) of the NW Sumas and West Coast Station 2.

On page 28 of Appendix C, FEI in Figure C-16 shows the actual regional daily prices as follows:

Figure C-16: Actual Regional Daily Prices

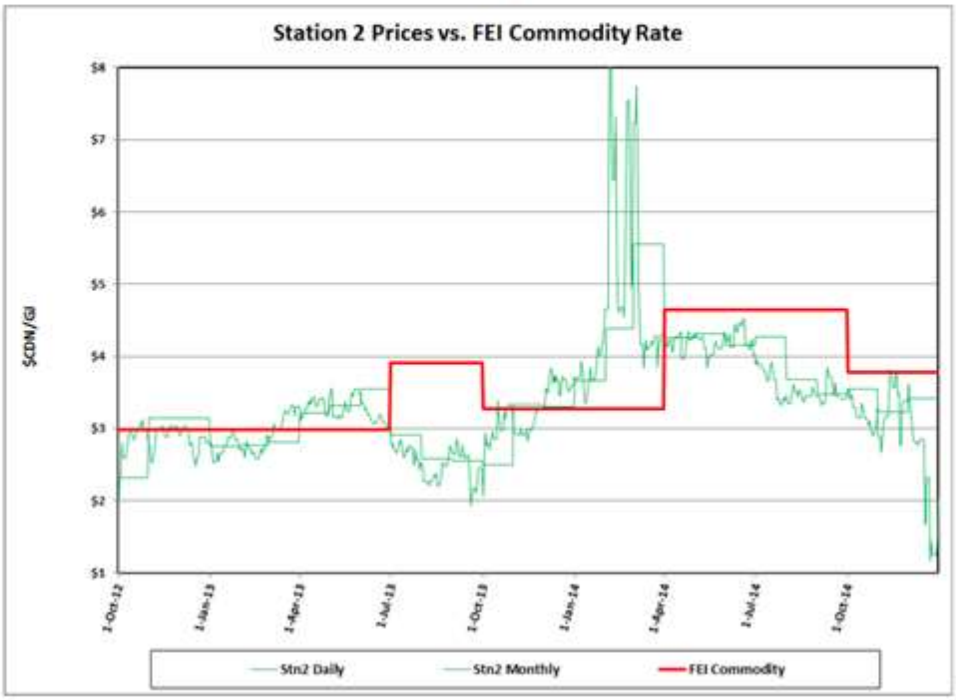
On page 29 of Appendix C, FEI provides Figure C-17 which shows the weighted average cost of gas (WACOG) vs. commodity rate (excluding hedging). FEI submits that its WACOG and commodity rate have fluctuated significantly throughout the past three years. FEI's commodity rate has moved from near $3/GJ in 2012 up to almost $5/GJ in 2014 and then back down again to near $2.50/GJ in 2015.

The Commission guidelines for gas cost rate setting were originally established in Commission letter L 5 01 dated February 5, 2001, and further modified in Commission letter L-40-11 dated May 19, 2011 (together the Guidelines). The Guidelines were established in 2001 in response to high gas prices and the need to change rates more frequently than once per year to ensure significant deficits were not accumulated in gas cost deferral accounts in times of rising prices. In establishing the Guidelines in letter L 5 01, the Commission took into account: rate stability, price transparency, implications for the expected size of the deferral account and efficiency of process.[23]

In Exhibit A2-1, as part of the FEI Price Risk Management Workshop Summary Report, FEI provides the Station 2 prices vs. FEI commodity rate, AECO/NIT prices vs. FEI CCRA rate, and commodity rate vs. spot market, for example:

[23] Commission Order G-37-14

Historical FEI Commodity Rate vs. Market Prices

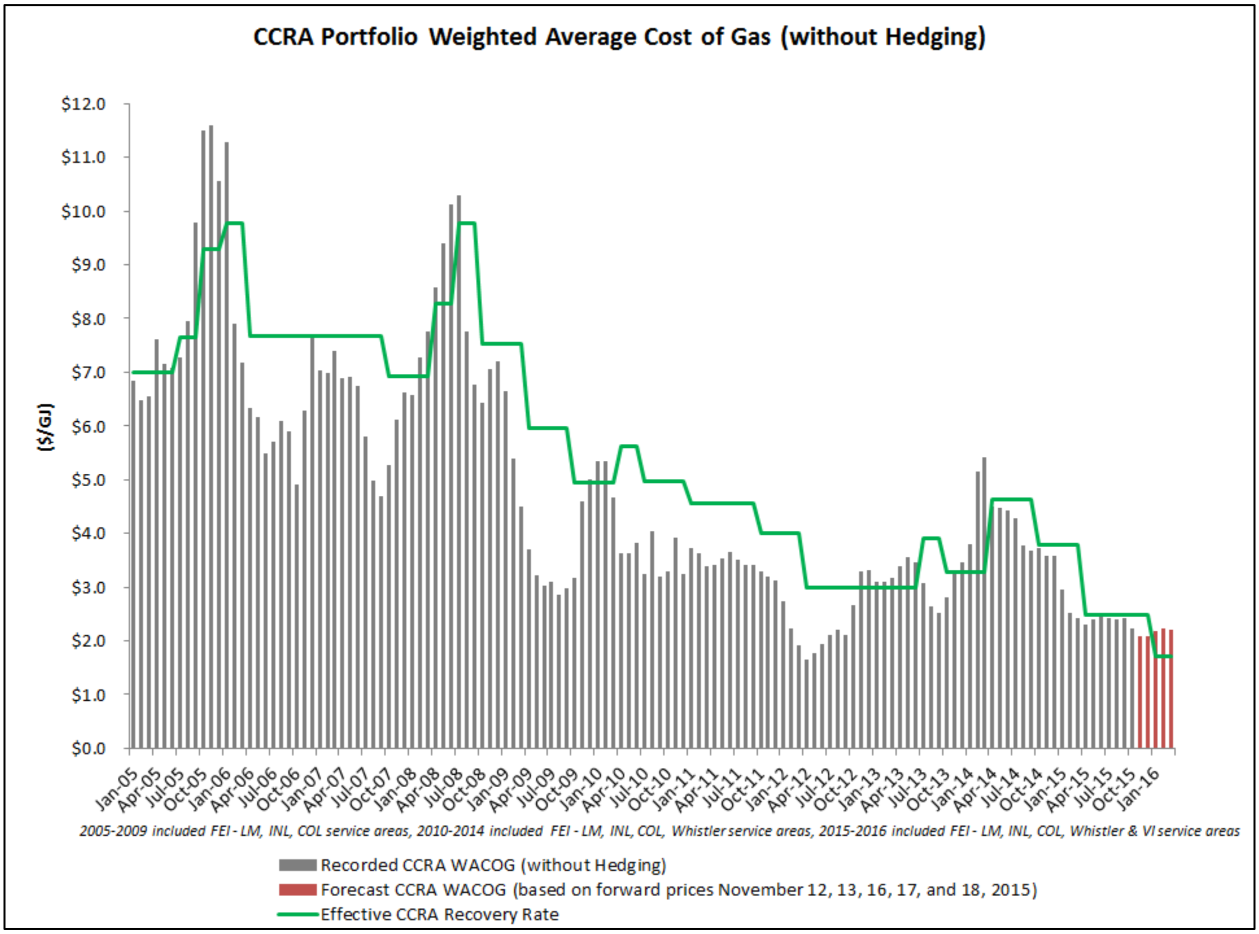


78

27.1 Please expand Figure C-17 to show the period from 2005 through 2015. Was the Commodity Cost Reconciliation Account (CCRA) rate more volatile pre-2012 as compared to 2012 through 2015?

Response:

The following figure illustrates the CCRA WACOG (without hedging) vs. the CCRA recovery rate from 2005 to March 2016.



Natural gas prices have been and continue to be one of the most volatile commodities in North America. The WACOG and the CCRA rate were volatile pre-2012 and continued to be volatile from 2012 through 2015.

Prior to the impacts of the shale gas boom which began in 2009, the overall natural gas price level was higher than today and the WACOG and CCRA rate fluctuated frequently with significant rate changes and spikes in the cost of gas. From 2010 to 2012, during the abundant shale gas period, the WACOG and CCRA rate changes moderated but continued to fluctuate.

Although the overall natural gas price level from 2012 to 2015 has lowered compared to historical price levels, the WACOG and CCRA rate remained volatile. As illustrated in the figure above, FEI experienced multiple CCRA rate changes from 2012 through 2015. The CCRA rate increased from $3.272/GJ to $4.640/GJ (a 42% increase) on April 1, 2015 before dropping down to $1.719/GJ as of January 2016 (a drop of 55% from January 2015).

27.2 As shown in Figure C-16, FEI noted the December 7, 2013 daily price at Sumas of $10.76/GJ. FEI also noted the February 6, 2014 daily price at Sumas, AECO and Station 2 of $28.54/GJ, $18.94/GJ, and $20.19/GJ, respectively. Please confirm that customer's CCRA rate – the commodity rate at which customers are actually paying – remained the same at $3.272/GJ from October 1, 2013 through March 31, 2014.

Response:

Confirmed. Although the CCRA rate remained at $3.272/GJ from October 1, 2013 through March 31, 2014, the CCRA rate was increased to $4.640/GJ (a 42% increase) on April 1, 2014. The rate impact from the price spikes in the winter of 2013/14 was delayed for two main reasons. First, the more significant price spikes occurred after FEI had already set the quarterly rate effective January 1, 2014. Second, the deferral account, capturing the difference between actual gas costs and customers' rates, had built into it a significant deficit position and so needed to be recovered from customers with the April 1, 2014 rate change.

27.3 As shown in the graph above provided in Exhibit A2-1, the CCRA rate (FEI Commodity) absorbs the volatility in market prices by way of the flow through and deferral of any surplus and deficit in the CCRA. With respect to Mr. Coyne's testimony "it is my experience that volatile natural gas prices and price spikes do factor into customers' perceptions of gas use", would Mr. Coyne and FEI agree that customers are not exposed to daily or monthly commodity market volatility through the commodity rate setting mechanism?

Response:

Customers are not exposed to daily or monthly commodity market volatility in the sense that their rate does not fluctuate with every change in price, but they are still exposed. The commodity rate setting mechanism includes the recovery or refunding of accumulated deferral account balances as well as the forward projection of gas costs based on forward market prices. The accumulated deferral account balance includes the impacts of any recent daily and monthly market price volatility. Furthermore, daily and monthly market price volatility typically influences the forward market prices as well.

Customers' perception is not only affected by their monthly bills but by what they hear on the everyday news as well. For instance, news regarding a change in natural gas prices may lead to some customers' anticipation of a similar immediate change in their monthly bills.

27.4 Please explain all tools available to FEI to mitigate the volatility of natural gas market prices. For instance, please discuss the purpose and objectives of the annual contracting plan (including physical hedge – storage, daily and monthly purchases, long term contracts, etc.), gas supply mitigation incentive program (GSMIP), and long term resource plan.

Response:

The tools currently available to FEI to mitigate the impact of the volatility of natural gas market prices include gas storage and various commodity purchasing strategies as defined in the Annual Contracting Plan (ACP), gas cost deferral accounts and the quarterly rate setting mechanism. For gas customers there are also optional programs available to help them smooth their monthly bills or fix their commodity rates. These include the Equal Payment Plan, Customer Choice Program and Rate Schedule 14A. Larger gas customers can also elect to use FEI for transporting their gas only but purchase their commodity supply with a variable or fixed rate from a natural gas marketer. FEI does not consider GSMIP and the long term resource plan as tools to mitigate the volatility of market prices.

As outlined in the ACP, FEI diversifies its gas supply portfolio in several ways to mitigate underlying market price volatility. For instance, FEI purchases physical supply at daily and monthly index prices from various supply hubs. Furthermore, the use of storage assets also plays a role in mitigating pricing volatility. Storage provides a natural physical winter hedge, as FEI purchases the gas to inject into storage during the summer, when prices are typically lower than winter prices. However, these tools within the ACP regarding FEI's supply portfolio still include market-based pricing and so FEI's gas costs and commodity rate are highly influenced by the volatility in the marketplace.

27.4.1 Is it fair to say that customers have tools available if they prefer to smooth out price volatility by way of the equal payment plan and/or fixing the commodity rate with a gas marketer? Please discuss all the tools available if the customer is averse to price volatility.

Response:

As was the case before 2012, customers do have other service offerings to smooth out bill volatility and commodity rate volatility available to them.

The Equal Payment Plan (EPP) is a tool available for customers to smooth out bill volatility but it has no effect on the underlying commodity purchase cost and therefore no impact on market gas price volatility. The EPP is designed to help customers avoid seasonal bill fluctuations with 12 monthly installments for budgeting purposes, as customers generally consume more natural gas in the winter months and less in the summer months. However, installment amounts are reviewed every three months and may be adjusted up or down due to changes in gas usage or commodity rates. Customers enrolled in the EPP can have their installment amount adjusted every three months. Currently, about 30% of eligible FEI customers have signed up for the EPP.

Eligible customers can lock in their commodity rate with a gas marketer with the Customer Choice program for one to five years and therefore smooth out commodity rate volatility during this period. Currently, about 5% of eligible customers are participating in the Customer Choice program.

27.5 Other than Mr. Coyne's the 45-day rolling average volatility (measured by standard deviation) of the NW Sumas and West Coast Station 2, please provide volatility indices for the period from 2005 to 2015 that FEI uses to track volatility for Sumas, Station 2 and AECO.

Response:

FEI does not track specific statistics or indices for historical market price volatility for market gas prices. There may be many different statistics or indices one could use to measure price volatility but FEI is not aware of any industry standards for tracking volatility. For the purposes of this Application, FEI has observed the historical market price and commodity rate changes and their frequency and magnitude in its assessment of the price volatility risk. Mr. Coyne has provided historical 45-day rolling average volatility measure by standard deviation in his assessment of the volatility risk.

27.6 In Table C-2, FEI describes the risk status of commodity price volatility since 2012 as "higher". When FEI describes price spikes and volatility, does FEI differentiate the underlying causes such as short-term weather impact and longer term impact from infrastructure for resource development?

Response:

No, FEI does not differentiate the underlying causes as price spikes and volatility can be caused by a combination of factors. These factors can include weather, capacity of connecting pipelines, plant outages, demand and supply of natural gas, prices of competing fuels, storage inventory levels, etc.

28.0 Reference: Exhibit B-1, Appendix C – FEI Business Risk Assessment, Section 5.2, Commodity Price Volatility, p. 31;

Commission letter L-28-15; FEI 2015/16 Annual Contracting Plan Executive Summary, p. ES-10

Energy price risk – T-South transport

On page 31 of Appendix C, FEI states:

> The potential for new regional baseload industrial load will result in greater competition for existing pipeline capacity on a year round basis… 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.
>
> While expanding the Spectra T-South system is an option, along with other pipeline solutions, these require long-term shipper commitments and several years to complete. While these proposed projects can also take years to complete, the timing of the completion of such projects does not always align with the required infrastructure, leading to the potential for supply/demand mismatches and price volatility.

As accepted by Commission letter L-28-15, FEI states on page ES-10 of its 2015/2016 Annual Contracting Plan:

> The most significant of these developments involves the potential for new incremental demand in the region and the resulting need to construct additional pipeline transportation capacity. The challenge these requirements create is the need to match the timing of when the new demand materializes with the construction of new pipeline capacity. A potential mismatch of these developments causes existing resource to be in much greater demand. In response FEI has been recontracting and extending the term of its existing resources to help ensure that the existing resources remain in the portfolio. FEI will continue to make appropriate changes to its portfolio as market conditions evolve in order to continue to be able to meet the objectives of the ACP.

28.1 Please confirm that FEI has the ability and has made effort to contract via the annual contracting plan for the appropriate Spectra T-South capacity to adequately mitigate potential supply/demand mismatches and price volatility. Please provide a public response and also a detailed confidential response (if it contains commercially sensitive information). Provide an explanation for confidentiality.

Response:

FEI has the ability to bring forward changes to the ACP to help mitigate some price volatility, and/or supply and demand mismatches given the availability of resources in the marketplace. There are still numerous factors outside of FEI's control that can cause supply/demand mismatches, and ultimately price volatility, that cannot be offset by FEI. For example, production could decline due to shut-ins or maintenance activities, while demand could increase due to cold winter events or from market growth. Furthermore, the third party transportation capacity that FEI and its customers rely on to move supply from Station 2 to Huntingdon is currently fully contracted. As a result, FEI and its customers could continue to experience significant price volatility on the day or month during cold winter events when demand is higher than the available pipeline capacity. Moreover, if incremental demand in the region comes online before any additional pipeline capacity is built, there would be an increase in price volatility in the market, especially at Sumas. Although under the current ACP, FEI sales customers are not directly exposed to price volatility at Sumas, the Transportation customers in the Lower Mainland are Sumas buyers, therefore they will be exposed to the price volatility occurring at this market hub. Further FEI sales customers would continue to be exposed to the price volatility at Station#2 and Aeco (Nit), where FEI buys gas to flow into its pipeline capacity that it holds.

29.0 Reference: Exhibit B-1, Appendix C – FEI Business Risk Assessment, Section 7.1.2, Midstream (Transportation and Storage), p. 54

Nova Gas Transmission Ltd. (NGTL) North Montney project

In Appendix C, FEI states:

> [T]he NEB attached several conditions to its recommended approval of the project, including the establishment of separately tolled project facilities unless NGTL comes forward with a new toll proposal. NGTL is expected to come forward with a proposal for a new toll methodology for these facilities that would allow them to be considered an extension of its existing system. NEB approval of such a proposal would impact FEI's ability to continue to access natural gas supply for its customers at competitive market prices, reduce liquidity at the Station 2 hub and increase FEI's cost of holding firm transportation capacity and storage resources. Shippers that today flow gas on T-North and move gas to the Station 2 or Alberta market could alternatively simply bypass the WEI system. Any reduction in the use of T-North and T-South systems will increase the costs to their captive shippers such as FEI.

In a news release dated April 15, 2015[24], the National Energy Board (NEB) stated:

> The Board has approved the applied-for rolled-in tolling design during a transition period, on conditions. The conditions include a requirement for NGTL to maintain a separate cost pool and separate accounting records for the Project.

Furthermore, in its report dated April 2015[25], the NEB stated:

> Intervenors noted the potential commercial impacts of the Project proceeding with the applied-for tolling methodology. FortisBC and EUG [Export Users Group] expressed concerns that if NGTL's proposed tolling methodology was applied to the Project, there would be decreased liquidity at Westcoast's Station 2 and potentially increased costs to access gas supplies. <u>The Board is of the view that its direction regarding tolling of the Project mitigates Intervenor concerns about the potential commercial impacts of the Project.</u> [Emphasis added]

29.1 Based on the NEB's conditional approval with the requirement for NGTL to maintain a separate cost pool and account records for the Project and given the NEB's views on its directions, would FEI agree that the NEB is sensitive the gas

---

[24] https://www.neb-one.gc.ca/bts/nws/nr/2015/nr18-eng.html

[25] https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90464/90550/554112/915551/1060220/2789084/2760037/Report_GH-001-2014_-_North_Montney_Mainline_-_A4K5R6.pdf?nodeid=2759936&vernum=-2

supply risk in BC, and thus, there is no immediate risk to Station 2's liquidity and the potential increased costs to shippers including FEI? Please discuss.

Response:

No, this risk remains. While FEI agrees that its intervention in NGTL's North Montney Project helped to highlight issues associated with the risk to gas supply in BC caused by the Project, this does not mean that the establishment of separate cost pools and account records for the Project by itself mitigates the gas supply risks the Project potentially causes for FEI. As part of the Western Export Group, FEI highlighted to the NEB significant problems that would be created by the proposed treatment of incremental delivery revenue by NGTL as part of the separate cost pools. If the proposed treatment by NGTL was accepted by the NEB, then it would provide for an unreasonably subsidized use of the Project facilities by the Project's proponents and also provide zero cost access to the rest of the NGTL system. This in turn would provide a significant incentive for producers to bypass Westcoast's T-North system and impact FEI's ability to continue to access natural gas supply for its customers for the reasons cited in the preamble to this question.

30.0 Reference: Exhibit B-1, Appendix C – FEI Business Risk Assessment, Section 6.2, Perception of Energy, pp. 41–42; Section 9, Political Risk, pp. 60–69

Perception of Energy and Energy Policies and Legislations

On page 63 of Appendix C, FEI assesses that the increased willingness of local governments to dictate energy choices represents a material increase in risk for FEI.

Figure C-24 on page 42 shows that initial willingness to adopt alternative energy sources to natural gas has reversed from 69 percent to 62 percent over a 4-year period. Moreover, survey respondents' receptiveness to natural gas rose from 16 percent to 34 percent over a 12 month period.

30.1 In FEI's view, in addition to the reasons cited in Figure C-24, does the low cost of natural gas commodity price have any effects on the survey results? Why or why not?

Response:

FEI is unable to draw any definitive conclusions regarding the effect of lower natural gas prices on the survey results. None of the quantitative surveys summarized in Figure C-24 specifically explored the effect natural gas prices had on respondents' willingness to adopt alternative energy sources. Further, the 69% referenced was established from a survey conducted in the summer of 2009, while the 62% referenced in 2013 was from a winter months' survey. Given margins of error (i.e., approximately ± 3.5% in each study) and the possible influence of seasonality, FEI cannot reliably conclude the results were materially different.

30.2 In FEI's view, in addition to the reasons cited in Figure C-24, does the change in the designation of natural gas as a source of clean energy for the purpose of LNG export have any effects on the perception of natural gas as a clean energy? Why or why not?

Response:

No. In FEI's view, the designation of natural gas as a source of clean energy for the purpose of LNG export will not have any material effects on the perception of natural gas as a clean energy source.

While the Provincial government has changed the designation as noted in the preamble, the fact that the change is very limited in scope reinforces the perception that, absent such a change in designation, natural gas is not a clean energy source. Furthermore, certain LNG facilities, such as the Woodfibre LNG project, are touting the use of electricity as opposed to natural gas in its liquefaction process as a beneficial and distinguishing factor, which casts a negative light on natural gas.

With respect to FEI's customers, as explained on page 61 of FEI's Appendix C, the power required for FEI's LNG facilities, as well as the proposed EGP project, is supplied by BC Hydro. Therefore FEI's customers are not directly impacted by this change to natural gas designation for LNG export.

Local governments, including those in the vicinity of the proposed LNG projects, continue to view natural gas as a non-clean fuel and strive to curb their natural gas consumption to reduce their GHG emissions.

31.0 Reference: Exhibit B-1, Appendix C – FEI Business Risk Assessment, Section 10, Regulatory Risk, pp. 74–75; Appendix A, , Section 2 – Credit Rating Agency Reports, Moody's report on FEI dated July 20, 2015

Risks related to PBR

On page 74 of Appendix C, FEI states that the Commission's decision in FEI's Application for a Multi-Year Performance Based Ratemaking (PBR) Plan for the years 2014 through 2018 exemplifies how an individual Commission decision can have implications for FEI's ability to earn its fair return. It explains that compared to cost of service regulation, performance-based rate-setting is subject to some additional risk associated with managing the controllable costs over a longer time horizon to a formulaic amount. FEI also provides three other specific aspects of the PBR Decision that have the potential to elevate regulatory risk for DEI during the PBR term.

Moody's credit opinion report states:

> PBR MARGINALLY INCREASES RISK
>
> The shift to PBR marginally increases risk because of the potential for increased cash flow volatility compared to cost of service regulation. However, we believe that management will be successful in achieving the challenges inherent in its PBR plan and continue to earn the allowed return on equity established by the regulator. While there is some increased regulatory risk pending resolution of some outstanding issues, particularly capital spending, once a precedent is established it will reduce regulatory risk for the PBR term. Performance based regulation utilizes a formula based approach to rate making. Revenues associated with controllable operating expenses and capital expenditure are adjusted on an annual basis during the 6 year period of the plan, from 2014-2019. Each year they are adjusted for inflation, a productivity or X-factor of 1.1% (FBC 1.03%), while initial rates were based on 2013 cost of service based rates with some adjustments. Many costs remain pass through items; for example, interest expenses and taxes limiting risk to the utility. The PBR plan has a symmetrical earnings sharing mechanism that is partially subject to service quality indicators. An annual review process forms part of the PBR plan to mitigate the risk of the plan failing to achieve its objectives. CPCN capital has been excluded from the PBR plan on a temporary basis, while different options are evaluated.

31.1 Does FEI agree with Moody's credit opinion that the management of FEI will be successful in achieving the challenges inherent in its PBR plan and continue to earn the allowed return on equity established by the regulator?

<u>Response:</u>

As noted on page 75 of Appendix C, Commission Order G-106-15 set FEVI's sustainment capital based on a five year average of FEVI's actual sustainment capital expenditures and reduced FEVI's previously approved 2014 sustainment capital by $6.3 million which resulted in a similar reduction to base capital expenditures for 2015 and each of the remaining years in the PBR term. This decision, coupled with the prior reduction of FEI's growth factor by 50 percent, has put significant pressure on FEI's capital expenditure performance.

In the first two years of the PBR Plan, FEI has achieved O&M savings in each year, but capital spending has been above the formula amount by a cumulative $11.4 million. As FEI stated in its Annual Review for 2016 Rates, "FEI was able to realize savings in O&M expenditures, while FEI's capital expenditures continue to be above the capital formula amount"[26] and "…the challenges FEI is facing in meeting its growth and sustainment capital formula spending amounts are expected to continue through the remainder of the term of the PBR Plan.[27]"

In summary, FEI will be challenged to spend within the capital formula set out in the PBR Plan, but expects to continue to achieve savings in O&M. In order to achieve the allowed ROE, FEI will need to ensure continued savings from O&M to offset the above noted capital challenges and the cumulative impacts of the O&M formula productivity factor. While FEI expects in the near term to achieve its allowed ROE, it is difficult to assess the likelihood of doing so further into the PBR term as possible future regulatory decisions, Z-factor decisions, further capital challenges and the impacts of the formula productivity factor create ROE pressures.

31.2 Under the cost of service regulation, has FEI been able to achieve is allowed ROE? Please provide an allowed and actual ROE comparison for FEI for the period 2000 to 2014 (historical) and 2015 (projected).

Response:

In the table below, FEI has provided the requested allowed and actual data for the 2000 to 2014 historical period. FEI has not provided the 2015 projected ROE because a current projection of all the components of rate base and the cost of service is not available. Given ROE is derived by all the individual components of rate base and cost of service, some of which are subject to variability, providing an accurate projected ROE is difficult and not necessarily reflective of the actual results that will occur. However, to be responsive and assuming all other components of rate base and cost of service are equal to the amounts approved in the Annual Review of 2015 Rates, the projected $10.2 million in O&M savings less the calculated earnings sharing amount in the Annual Review for 2015 rates would result in an after-sharing ROE of 9.05 percent (9.39 percent before-sharing).

For the years FEI was under cost of service (2002-2003 and 2010-2013), FEI has been able to achieve its allowed ROE in each year except 2010, where the actual ROE was less than the approved ROE. In 2002, an approved revenue requirement did not exist for that year so the amounts cannot be compared.

[26] Page 4 of FEI's Annual Review for 2016 Rates Application.
[27] Page 7 of FEI's Annual Review for 2016 Rates Application.

	ROE		
	Allowed[1] (a)	Actual Pre-ESM (b)	Actual Post-ESM[2] (c)
2000	9.50%	10.75%	10.12%
2001	9.25%	9.38%	9.31%
2002	N/A	9.73%	N/A
2003	9.42%	10.23%	N/A
2004	9.15%	9.34%	9.25%
2005	9.03%	10.78%	9.91%
2006	8.80%	10.47%	9.64%
2007	8.37%	10.73%	9.55%
2008	8.62%	10.64%	9.63%
2009	8.99%	11.89%	10.44%
2010	9.50%	9.42%	N/A
2011	9.50%	10.15%	N/A
2012	9.50%	10.12%	N/A
2013	8.75%	9.12%	N/A
2014	8.75%	9.54%	9.20%

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 (2000-2001, 2004-2009, 2014)

C. DIRECT TESTIMONY OF MR. JAMES M. COYNE

32.0 Reference: Exhibit B-1, Appendix B – Evidence of Mr. James M. Coyne, p. 19, Exhibit JMC-3, FEI Canadian & US Bond Yield Averages

Utility yield and bond spread changes since 2012

On page 19 of Appendix B, Mr. Coyne discusses the yields and spreads on utility A-rated bonds and how those have changed since June 2012 and what this indicates in terms of risk aversion.

32.1 Please confirm that the most recent Canadian A-rated utility bond yield shown in JMC-3 is 3.89 percent and that it was 3.91 percent in June of 2012.

Response:

Mr. Coyne confirms that the most recent Canadian A-rated utility bond yield shown in JMC-3 is 3.89 percent and that it was 3.91 percent in June of 2012.

32.2 Please discuss if FEI's bond spread has changed in relation to the bond spread of other relatively pure-play Canadian regulated gas and or electricity distribution utilities.

Response:

Mr. Coyne has compared the change in long-term bond spreads of FEI relative to the gas and electric distribution companies included in the Canadian proxy group (Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc., and Valener Inc.) used in Mr. Coyne's Direct Testimony for three separate time periods: June 2012 (when evidence was last filed in the prior GCOC proceeding), August 2015 (the date of Mr. Coyne's evidence in the current proceeding) and November 2015 (the most recent data available). Mr. Coyne also compared FEI's bond spreads to the Canadian Corporate A-rated bond spread for the same three time periods. Mr. Coyne utilized Bloomberg data for long-term (15+ years) bond issuances for each gas or electric distribution subsidiary for each period. The proxy group electric and gas distribution companies for which long term bond yield data were available in Bloomberg were: Canadian Utilities, Nova Scotia Power Inc., Enbridge Gas Distribution Inc., Maritime Electric Co Ltd., Newfoundland Power Inc, Fortis BC Inc., Fortis Alberta Inc., and Gaz Metro Inc. Mr. Coyne has selected this group of companies because it is representative of the gas and electric distribution interests of the Canadian proxy group. From the long-term utility bond yields he subtracted the applicable (Canadian or U.S.) 30 year government bond yield to calculate the spread. (He selected the 30 year bond yield because it was sufficiently long term and most issuances had a remaining maturity of 20 to 30 years; and using the same government bond to calculate all spreads provided a better basis for comparison). Mr. Coyne also added the Canadian Corporate A spread to the analysis. Mr. Coyne's analysis is summarized below.

	LT Bond Spread over 30-yr Gov. Canada			Change in Bond Spread	
	April to June 2012	June to August 2015	Sept. to Nov. 2015	June 2012 to August 2015	June 2012 to Nov. 2015
FEI	**1.47**	**1.70**	**1.82**	**+0.23**	**+0.35**
CU Inc	1.45	1.72	1.84	+0.27	+0.39
Nova Scotia Power Inc	1.72	1.86	1.99	+0.14	+0.27
Enbridge Gas Distribution Inc	1.47	1.72	2.01	+0.25	+0.54
Maritime Electric Co Ltd	1.27		1.87		+0.60
FortisBC Inc	1.48	1.71	1.92	+0.23	+0.44
Fortis Alberta	1.42		1.89		+0.47
Gaz Metro	1.48	2.13	1.78	+0.65	+0.30
Average Canadian Distribution Cos.	**1.48**	**1.80**	**1.88**	**+0.32**	**+0.40**
Canadian Corporate A	**1.56**	**1.81**	**1.87**	**+0.25**	**+0.31**

Source: Bloomberg

As the Table above illustrates, bond spreads have increased since June 2012, indicating an increase in the cost of both utility and corporate credit risk over the period. The Table shows that FEI's bond spread has increased relative to June 2012, generally following the trend of Canadian Corporate A-rated bonds. The data also indicates that the Canadian distribution utilities as a whole have bond spreads that are slightly above FEI's bond spreads and the Corporate A-rated bonds. Differences are at least in part due to the lack of consistent bond pricing data across all bond issues and the use of different bond issues (with different terms) for the average spread calculations reported above for each time period. Please refer to the calculations in Attachment 32.2.

32.2.1 Please discuss if any such change in FEI's relative bond spread would be a useful indicator of whether the bond market perceives that FEI's risks have changed since 2012 relative to other utilities.

<u>Response:</u>

Mr. Coyne believes that relative bond spreads could be a useful indicator of whether the bond market perceives a change in FEI's risk since 2012. However, this tool should be used to complement a broader risk analysis and should not be used in isolation. Evidence of changes in FEI's bond yields is influenced by the availability of data, the type of bond, new bond issuances, the bond terms, the maturity of the bond, etc. In addition, it is not possible to determine what portion of the change in FEI's bond yield is due to changes in the bond market itself versus the change due to FEI's risk profile. A comparison to the Corporate A bond is informative in that it provides a benchmark bond spread, but the conclusions we can draw from a relative comparison requires an assumption that any differences in changes in FEI's bond spreads from those of the Corporate A bond spread would be due entirely to FEI's risk profile. In light of the above, a relative bond spread analysis could provide meaningful information to assess credit risk over a given period, but conclusions drawn from such an analysis should be corroborated by other evidence.

32.3 Please discuss if the typical bond spread of relatively pure-play Canadian regulated gas and or electricity distribution utilities has changed since 2012 in relation typical A-rated corporate bonds.

Response:

According to the analysis provided above in BCUC IR 1.32.1, for the Canadian utilities surveyed (with bond issuances), utility bond spreads have increased more than the Corporate A-rated bond spreads.

33.0 Reference: Exhibit B-1, Appendix B – Evidence of Mr. James M. Coyne, Section II, A – The Fair Return, pp. 10–11; Section V, A – Methods for Determining ROE, p. 34

Required returns by investors

In Section II A. of his expert testimony, Mr. Coyne describes the definition of the Fair Return Standard and its application. He submits on page 10 that the assessment of whether the Fair Return Standard has been met requires an examination of the required returns by investors in like-risked enterprises.

On page 34, under the topic of Methods for Determining ROE, he states: "While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on market information."

One aspect of market information is the price at which the shares of relatively pure-play Canadian and US regulated utilities trade in relation to the equity in rate base per share upon which an ROE is allowed and earned. Another aspect is the percentage premium (if any) to rate base which has been paid in merger and acquisition activity to acquire relatively pure-play regulated utilities in Canada and the US. While the purchasers' expectations regarding earnings growth as well as the purchasers' required return, that have led to these market prices, cannot be known with certainty, it may be possible to estimate reasonable growth assumptions given the highly regulated nature of the earnings.

33.1 In preparation for his testimony for this proceeding, has Mr. Coyne carried out any survey research on the required returns by investors in FEI-like enterprises, lower and higher risk enterprises in Canada, US and globally? If so, please provide the results of his research. If not, please explain why not.

<u>Response:</u>

Mr. Coyne has not carried out survey research on the required returns by investors in FEI-like enterprises, or lower/higher risk enterprises in Canada, the U.S. or elsewhere, nor is he aware of survey information on required equity returns for utilities or companies of similar risk to FEI. Mr. Coyne has estimated the required ROE using analytical techniques to quantify investor expectations regarding required equity returns.[28] Mr. Coyne's cost of capital analysis produces an estimate of the required returns of such like risked enterprises to FEI both in Canada and the U.S. As can be found in Mr. Coyne's evidence, through the development of a DCF and CAPM analysis for both a U.S. and Canadian proxy group, he has estimated the required returns of the proxy companies. The results of this analysis are laid out in Mr. Coyne's testimony in Table 1 on page 5. He has also considered each individual company's risk profile relative to FEI and

[28] Coyne Direct Testimony p. 34, lines 12-13.

developed a composite perspective of the proxy group risk profile relative to FEI (see Table 20, p. 101) to determine whether an adjustment for risk should be made. As Mr. Coyne explains in the above cited passage to this question (also found on p. 34 of his testimony), the cost of equity is not directly observable and must be estimated based on market information.

33.2 Can FEI or Mr. Coyne provide the panel with information regarding the ratio of price paid to rate base as well as an estimate of the price paid for the equity portion as a percentage of the equity portion of rate base in the acquisition of relatively pure play regulated utilities in Canada and the US?

Response:

Mr. Coyne takes issue with the preamble to this series of questions. Mr. Coyne believes that the premium paid for shares in the market or the acquisition premium paid to acquire highly-regulated entities provides only very general information on investors' earnings growth assumptions and provides no meaningful information with respect to investors' required returns. Every transaction has its own set of assumptions and even regulated entities provide opportunities for synergies that do not exist in isolation, i.e. tax considerations, financing structure, cost reduction, operating synergies, vertical integration, growth in new or existing service areas, etc. We can estimate the value an investor has paid over the rate base of a regulated entity, but do not know the justification, i.e. cost reduction, first step to a larger strategy, revenue growth, etc. The value attributed to a regulated utility in an acquisition does not reside solely in the value of the utility but rather is the value created by the addition of that utility to the Company's asset portfolio and the contribution the utility will make in achieving the company's strategic goals. As such, it provides very general information as to perceived value of the deal by the investor but very little information on how that investor would view the utility in isolation. Mr. Coyne agrees with the comments submitted in BC's last Generic Cost of Capital Proceeding by capital markets expert, Aaron Engen. Mr. Engen provided the following responses to information requests, posed to him in that proceeding:

Mr. Engen opposes the view that observers can draw conclusions regarding expected returns flowing from regulated asset acquisitions based only on the regulated asset's allowed ROE. Allowed ROE is one of many factors that drive expected cash flow from an investment in regulated assets. Other factors which can increase expected cash flows include changes in ROE, operating efficiencies, implementation of PBR regimes or increased benefits from current PBR regimes, and double dip interest deductibility.

In addition, regulated asset purchasers may have opportunities to increase cash flows away from the regulated business including access to other, higher ROE assets or

> *businesses which are acquired alongside the regulated business, introduction of double leverage at a "holdco" level, and the opportunity to provide appropriately approved business services to the regulated business (engineering services, for example).*
>
> *Rather than incorrectly considering one factor, allowed ROEs, when attempting to evaluate what returns buyers expect on acquiring a regulated asset, one should instead consider all sources of potential cash flows relevant to the purchaser at the time of the acquisition. The difficulty, then, is that the foregoing information is not known to transaction observers. It is only known to the purchaser and its advisors. Because the information cannot be known by observers, any calculation of expected returns on capital from a regulated asset purchase will necessarily be incorrect.*[29]

In another response to an information request by the BCUC, Mr. Engen explains why it is inappropriate, in cases where utilities' shares exceed price/earnings ratios of the broader market, to attempt to adjust utilities allowed ROEs such that utility price/earnings multiples are aligned with the market. Mr. Engen responds:

> *The concept of adjusting allowed ROEs to manage utility share prices in such a fashion so as to keep utility price/earnings multiples in line with the market is not feasible nor is it desirable.*
>
> *To begin with, multiple regulators may be involved with setting allowed ROEs for a corporation's regulated businesses (as is the case with Fortis Inc.). The more a utility's operations are overseen by different regulators, the less ability any one regulator has to effect change in the utility's share price and market valuations. In many cases rate-regulated, cost-of-service assets comprise only a portion of the utility owner's businesses. The ability to determine which assets, non-regulated vs. regulated, are supporting the higher valuations is, at best, questionable. Were the company's non-regulated operations to be more attractive to the market, the regulator would have to more heavily penalize the regulated assets in order to manage down the company's earnings valuations to offset the positive P/E valuation impact of the non-regulated business.*
>
> *P/E multiples may change for reasons not connected with allowed ROEs. For example, a company may be expecting material growth in nearer-term earnings which the market is willing to pay for (at least in part) in the current year. In such a case, one would expect the company's P/E ratio to rise and, perhaps, substantially so. In such case, it would be perverse to reduce allowed ROEs in an attempt to lower P/E ratios when the reason they were high in the first instance had nothing to do with allowed ROEs.*

[29] Aaron Engen's Response to BCUC IR 1.30.1, Generic Cost of Capital Proceeding, Stage 1, submitted September 24, 2012.

> *Finally, adjusting allowed ROEs to keep P/E multiples in line with the market would result in increased volatility in regulated asset earnings as allowed ROEs are manipulated upwards and downwards. The end result of such an exercise would be to turn regulated asset earnings into assets with the same earnings volatility as the market. Doing so would bring regulated asset risk closer to, if not to, the market's level of risk and result in an increase regulated asset cost of capital.*[30]

Indeed, the question of whether utility allowed earnings should be adjusted to arrive at a target market to book or price earnings ratio has been examined by regulatory theorists and academics. Dr. James Bonbright opines:

> *Should the allowed rate of return be designed to prevent the market prices of public utility equities from rising to substantial premiums above book values? A rigorous and literal application of a cost-of-capital measure of a fair rate of return in the above-outlined sense of this measure would mean an attempt by a commission to regulate rates of charge so as to maintain the market prices of utility equities on a par with their book values or rate-base values plus some stipulated allowance for necessary underpricing. Yet a mere reference to any such attempt should suffice to suggest its absurdity. In the first place, commissions cannot forecast, except within wide limits, the effect of their rate orders on the market appraisals of the stocks of the companies subject to these orders. But in the second place, whatever the initial market appraisals may be, they are sure to change not only with the changing prospects of earnings but with the changing outlook of a notoriously volatile stock market. In short, market prices are beyond the control, though not beyond the influence, of rate regulation. Moreover, even if a commission did possess the power of control, any attempt to exercise it in the* manner just suggested would result in harmful, uneconomic shifts in public utility rate levels…

> *…Regulation is simply powerless to assure the purchasers of public utility equities that future corporate earnings will suffice to maintain market prices on a par with book values or with any other dollar figure. Lacking this power, regulation wisely concedes to the public utility industries opportunities for corporate earnings liberal enough to bring to substantial market premiums the stocks of those well-managed companies that actually succeed in realizing these earnings fairly continuously. But while the allowance of a rate of return, during periods of prosperity, liberal enough to let utility equities command substantial premiums over their book values seems to me to be called for in the interest of long-run corporate ability to meet capital requirements, the question what constitutes a proper degree of liberality has not yet received a convincing answer. Indeed, I doubt whether a conclusive answer can ever be found under such an indefinite standard of a*

[30] Aaron Engen's Response to BCUC IR 1.3.1, Generic Cost of Capital Proceeding, Stage 1, submitted September 24, 2012.

> *fair rate of return as that of a flexible rate designed to rise and fall with changes in anticipated rates of income necessary to induce new investments of equity capital.*[31]

Though we find no recent discussion in Commission Orders of any inferences that can be drawn from acquisition premiums and trading values above 1, the Commission Panel did provide comments on these topics in its 2006 FEI Cost of Capital Decision. In that Decision, though the Commission acknowledged several competing philosophies on the relevance of such information, the Panel ultimately found no specific relevance for the acquisition premium information and stated:

> *The Commission Panel agrees with the AEUB that acquisition premiums may result from a number of strategic factors which are unrelated to the establishment of a fair return for a benchmark low-risk utility. The Commission will continue its practice of allowing utilities subject to its jurisdiction, to earn a fair return on the value of their investment in property, the value of which does not include a premium on acquisition*[32]*.*

The Commission has requested metrics on deal value over book value and over utility rate base for recent acquisitions. This is not a metric that we would rely upon for the reasons discussed above, i.e. there is no way to know the value stream that investors attach to either the regulated or unregulated operations of the business. With those caveats, Mr. Coyne has included the requested information in the attached table on relatively significant acquisitions/ mergers in the U.S. and Canada within the last few years. In particular, the table provides key background information for each of the mergers/ acquisitions and then provides the following quantitative information:

1. Announced Deal Value (Price)
2. Total Rate Base – This is calculated by summing the best available data for rate base for each of the gas or electric distribution companies owned by the company being acquired.
3. Weighted Equity Ratio - This is the aggregate equity ratio of all the gas and electric distribution companies for which data was available.
4. Total Equity Portion of Rate Base – This is calculated as the sum of the equity portion of rate base of all the gas and electric distribution companies being acquired.
5. Book Value identified at the time of the acquisition.

---

[31] Bonbright, James C. Principles of Public Utility Rates. New York, Columbia University Press, 1961, pages 254 through 256.

[32] BCUC Decision, Terasen Gas Inc., *To Determine the Appropriate ROE and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism*, March 2, 2006, at p. 52.

6. Deal Value/ Book Value – Calculated on a per share basis.
7. Rate base equity as a percentage of book value.
8. Announced Deal Value Attributable to Distribution Utilities to Rate Base Equity ratio. (The price times the value calculated in 7, divided by the rate base equity, shown as a percentage).

It should be noted that in some cases, complete or final information is not publically available, for example, on the rate base approved in settlements. Please refer to Attachment 33.2 for the analysis of the best information available, and, in some cases, notes where no information could be found. Interpretation of this information is provided in response to BCUC IR 1.33.3.

33.3 Please provide Mr. Coyne's views on the interpretation of the returns required by investors in the market, based on the premiums at which the rate base and equity in rate base of relatively pure-play regulated utilities trades in the market in relation to the regulated rate base upon which a regulated return is earned.

Response:

There are many factors that lead to the negotiated price in utility mergers and acquisitions. Projected earnings of the regulated local distribution company are one part of the picture, but many other factors drive these valuations. As Mr. Coyne has indicated in his response to BCUC IR-1.33.2 above, some of those non-return factors that may influence an acquirer to pay large premiums for regulated assets over book value are tax considerations, financing structure, cost reduction, operating synergies, vertical integration, or growth in new or existing service areas. Below, I discuss some of these factors.

One factor driving value in a merger is the opportunity to achieve cost savings. By combining similar companies that perform certain similar functions, merging entities envision and capture opportunities for reducing costs over time, resulting in customer and shareholder benefits. For example, a core part of the recent merger of Northeast Utilities and NSTAR completed in 2012, was a projected benefit of $780 million in net savings over 10 years to be shared with customers, a portion of which was immediately credited to customers.[33]

[33] Press Release "NU/NSTAR Merger Closes, Creating New England's Premier Utility Company" (April 10, 2012) http://www.businesswire.com/news/home/20120410006040/en/NUNSTAR-Merger-Closes-Creating-England%E2%80%99s-Premier-Utility.

This connects to another common rationale for mergers and acquisitions: the ability to bring a greater level of expertise and capacity in order to improve service and performance, and often reduce costs. Mergers and acquisitions provide an opportunity to create value when superior practices can be implemented. A statement from the NU/ NSTAR Merger press release again captures this concept, as stated by Thomas J. May, President and CEO of the combined company: "This merger puts us in a unique position to provide better service levels … [T]ogether we have the scale, talent and financial resources to meet the complex and demanding energy needs of our customers across New England." [34]

Further, mergers or acquisitions may allow a company to further a particular vision or philosophy. This is illustrated in the proposed merger between NextEra and Hawaiian Electric Industries, Inc. (HEI). In that case, the two companies tout the alignment between the environmental values of the HEI's customers, and NextEra's strong clean energy portfolio. This is reflected in the companies' press release, which states: "The transaction brings together two industry leaders in clean and renewable energy. The Hawaiian Electric Companies… have put Hawaii on the leading edge of clean energy nationally…. NextEra Energy adds its strength as the nation's leading clean energy company. NextEra Energy shares Hawaiian Electric's vision of increasing renewable energy, modernizing its grid, reducing Hawaii's dependence on imported oil, integrating more rooftop solar energy and, importantly, lowering customer bills." [35]

Another factor that can be significant is business opportunities outside of regulated distribution operations. Opportunities for investments beyond the local distribution business, such as natural gas pipelines, electric transmission lines, or competitive retail business may be significant drivers of mergers or acquisitions. This is exemplified in the press release announcing the proposed merger between NSTAR and Northeast Utilities. In addition to pointing to the distribution companies, Mr. May referred to the growth potential from "NSTAR's very strong balance sheet coupled with Northeast Utilities' impressive array of transmission investment opportunities."[36]

Similarly, in Kinder Morgan's acquisition of Terasen Gas in 2005, Kinder Morgan's Treasurer, made the following statements regarding the transaction and why Kinder Morgan would pay 2.7 times book value for a regulated utility. Mr. Bryson stated, "Well, I think that 2.7 book value was for the entire Terasen entity, which includes not just the gas utility business, but includes the pipeline business and the water business. You know, as we've indicated to investors over the past several years and demonstrated to investors over the last several years, we've got

---

[34] http://www.businesswire.com/news/home/20120410006040/en/NUNSTAR-Merger-Closes-Creating-England%E2%80%99s-Premier-Utility

[35] Press Release: "NextEra Energy and Hawaiian Electric Industries to Combine" (December 3, 2014) http://www.nexteraenergy.com/news/contents/2014/120314.shtml.

[36] Northeast Utilities and NSTAR Agree to $17.5 Billion Merger of Equals, Forming New England's Premier Utility Company. October 18, 2010. http://www.businesswire.com/news/home/20101018005866/en/Northeast-Utilities-NSTAR-Agree-17.5-Billion-Merger

tremendous growth potential in our pipelines business…I think, you know, their public statements are clear that they saw the greatest potential in the pipelines business. When you add up the various growth opportunities that Terasen has in front of it, I mean, we're a $5-billion organization currently, with more than $5 billion of growth potential in that business segment alone."[37] It should be noted that the Commission Panel in that decision found no relevance of the Terasen transaction price-to-book ratio to setting the ROE and capital structure for the benchmark utility.[38]

Another reason why a utility may undertake to acquire another utility is the opportunity to enter or strengthen its position in another aspect of the energy industry. For example, in describing the rationale for Southern Company to acquire AGL Resources, Southern Company Chairman, President and CEO Thomas A. Fanning stated, "[W]e believe the addition of AGL Resources to our business will better position Southern Company to play offense in supporting America's energy future through additional natural gas infrastructure… For some time we have expressed our desire to explore opportunities to participate in natural gas infrastructure development. With AGL Resources' experienced team operating premier natural gas utilities and their investments in several major infrastructure projects, this is a natural fit for both companies." [39]

Other factors that drive mergers include the creation of a larger company for improved capital market access, to better cope with increased environmental requirements and costs, geographic diversification, earnings diversification, or management team succession.

In sum, there are several factors that drive mergers and acquisitions, as well as opportunities for creating future value. Further, it must be recognized that the data requested utilizes rate base which is a depreciated value, and not reflective of the current replacement cost of these assets, some of which were built many decades ago. As indicated in Mr. Coyne's response to BCUC IR 1.33.2, acquisition premiums cannot be used with any accuracy to assess the adequacy of allowed returns, and to quote regulatory theorist, James C. Bonbright, when considering whether it is appropriate to attempt to design allowed returns such that market prices of utility equities are on par with book value, Dr. Bonbright stated, "any attempt should suffice to suggest its absurdity."[40] One cannot simply look at the ratios or percentages in the response to BCUC IR 1.33.2 and come to meaningful conclusions regarding the reasonableness of a rate of return.

---

37 BCUC Commission Decision 2006-03-02 FEI Cost of Capital and Capital Structure (March 2, 2006) at 11.

38 Ibid at 13.

39 Southern Company Press Release "Southern Company to Acquire AGL Resources in $12 Billion Transaction, Creating Leading U.S. Electric and Gas Utility" PRNewswire. August 24, 2015. http://www.prnewswire.com/news-releases/southern-company-to-acquire-agl-resources-in-12-billion-transaction-creating-leading-us-electric-and-gas-utility-300132138.html.

40 Bonbright, James C. Principles of Public Utility Rates. New York, Columbia University Press, 1961, page 255.

34.0 Reference: Exhibit B-1, Appendix B – Evidence of Mr. James M. Coyne, Section III, A – Summary of Current Economic and Capital Market Conditions, pp. 13–17

Business and Economic Conditions in Canada and the US

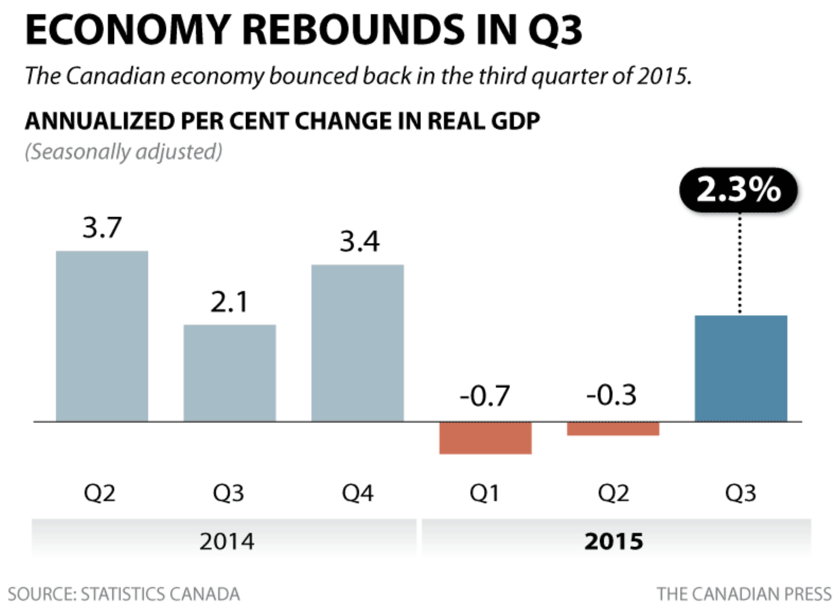
In Section III A. of his expert testimony, Mr. Coyne describes the increasingly interdependent set of relationships between countries in the global economy. Mr. Coyne summarizes the financial outlook as prepared by the Bank of Canada, the Consensus Economics, among others.

34.1 In the October 2015 issue of the Bank of Canada Banking and Financial Statistics[41] that was released on October 29, 2015, the data indicated: (i) a downward trend in the annual rates of monetary aggregates from 2012 onwards; (ii) an upward trend in total business credit; (iii) a downward trend in unemployment rate; and (iv) an inflation rate (total CPI excluding food and energy) from 2014 onward that is in line with the target range of between 1 to 3 percent as opposed to the below target range experienced in late 2012 and early 2013. In Mr. Coyne's view, are these positive trends in the macro-economic conditions for Canada?

Response:

Looking at the latest economic data from the Bank of Canada and Statistics Canada, it appears that the Canadian economy has shown resilience while facing pressures from weak resource prices. As pictured below, real GDP rebounded to an annual rate of real growth of 2.3% in the third quarter, following two consecutive quarters of negative growth (a technical recession).

[41] http://www.bankofcanada.ca/publications/bfs/ Tables A1 and A2.



Source: http://www.cbc.ca/news/business/canadian-economy-gdp-1.3344905

The changes in specific indicators cited in the question, in Mr. Coyne's view, portray a mixed outlook for the Canadian economy—some positive, others negative. The downward trend in M1+ from 2012 would generally signal a softening in the economy, as witnessed in the first 2 quarters of 2015, just as the uptick in August and September signaled a strengthening economy. The broader measure of money supply, M2++, has actually increased since 2012, signaling an upward movement in inflationary pressure. The growth in business credit is generally considered a positive economic sign, although it has slowed in recent months. The Canadian unemployment rate has stubbornly hovered in the 6.7-6.9% range over the first three quarters. The Bank of Canada attributes the national unemployment profile to a marked increase in unemployment in the energy producing provinces against a flat picture in other regions. On balance, the Canadian economy has added about 160,000 net new jobs over the past year.[42] The relatively stable trend in inflation within the Bank's target range signals a continuation of accommodative monetary policy designed to stimulate economic growth, consistent with the Bank's most recent decision on December 2 to hold the target overnight rate at 0.5%.[43]

---

[42] Bank of Canada Monetary Policy Report, October 2015, p. 18.
[43] http://www.bankofcanada.ca/2015/12/fad-press-release-2015-12-02/.

34.2 Based on the financial indicators and in Mr. Coyne's professional judgment, which part of the economic cycle is Canada currently in in the last quarter of 2015?

Response:

The upturn in GDP growth in the 3rd quarter signals a return to economic expansion from the contraction of the first two quarters, but as discussed in the response to BCUC IR 1.34.1, there is a mixed outlook. The Bank of Canada has provided an interesting analysis that decomposes GDP growth over 2015, separating out the effects of lower oil prices and temporary factors. This analysis shows the Canadian economy has otherwise remained in an expansionary cycle, and is expected to remain so (with or without these factors) in the 4th quarter. Mr. Coyne finds this a reasonable view.

Table 5: Decomposition of real GDP growth

Quarter-over-quarter percentage change at annual rates

	2015			
	Q1	Q2	Q3	Q4
Real GDP growth rate	-0.8	-0.5	2.5	1.5
Impact of temporary factors (in percentage points)[a]	-0.6	-0.2	0.8	0.1
Net impact of the oil price decline (in percentage points)	-1.6	-1.0	-0.4	-0.4
Real GDP growth excluding the impacts of temporary factors and the oil price decline[b]	1.4	0.6	2.1	1.8

a. Temporary factors include severe winter weather in North America, oil and gas shutdowns impeding oil sands output, refinery outages, motor vehicle plant shutdowns for extensive retooling, and retroactive payments related to the Universal Child Care Benefit.

b. Numbers may not add to total because of rounding.

Source: Bank of Canada Monetary Policy Report, October 2015, p. 18.

34.3 Based on financial indicators and in Mr. Coyne's professional judgment, are the economies of Canada and the US moving in sync in the economic cycle?

Response:

The economies of Canada and the U.S. remain closely interdependent. The relative strength in the U.S. economy is a key driver of the Canadian economy. As noted by the Bank of Canada in its October report: "robust growth in private domestic demand in the United States—Canada's main trading partner—is driving stronger foreign demand for Canadian exports."[44] Perhaps the greatest current difference is the relative impact of lower oil prices, which are a net positive for the U.S. economy and a net negative in Canada, even though the oil & gas extraction industries are negatively impacted in both. Despite these differences, the GDP data suggest the two economies remain relatively in sync, although not perfectly so, as illustrated below:

	Real GDP Growth	
	Canada	U.S.
2012	1.8	2.2
2013	2.0	2.2
2014	2.5	2.4
2015 1Q	-0.2	-0.2
2015 2Q	-0.1	3.9
2015 3Q	2.3	2.1

(A note of caution: the recent economic data is subject to revision, and at times these revisions are significant.)

The Bank of Canada's forecasts suggest a continuation of this long-term trend—the Canadian and U.S. economies moving in sync, which in Mr. Coyne's opinion, is the likely scenario based on the interdependency of the two economies.

Table 1: Projection for global economic growth

	Share of real global GDP[a] (per cent)	Projected growth[b] (per cent)			
		2014	2015	2016	2017
United States	16	2.4 (2.4)	2.5 (2.3)	2.6 (2.8)	2.5 (2.6)
Euro area	12	0.9 (0.9)	1.5 (1.2)	1.5 (1.3)	1.5 (1.4)
Japan	4	-0.1 (-0.1)	0.6 (0.8)	0.8 (1.2)	0.7 (1.2)
China	17	7.3 (7.4)	6.8 (6.8)	6.3 (6.6)	6.2 (6.4)
Oil-importing EMEs[c]	33	3.7 (3.8)	3.2 (3.6)	3.8 (4.1)	4.2 (4.4)
Rest of the world[d]	18	2.9 (2.9)	1.3 (1.8)	2.7 (3.2)	3.2 (3.2)
World	100	3.4 (3.5)	3.0 (3.2)	3.4 (3.7)	3.6 (3.7)

[44] Bank of Canada Monetary Policy Report, October 2015, p. 2.

Table 3: Summary of the projection for Canada[a]

	2014	2015				2016				2017			
	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Real GDP (quarter-over-quarter percentage change at annual rates)	2.2 (2.2)	-0.8 (-0.6)	-0.5 (-0.5)	2.5 (1.5)	1.5 (2.5)	2.0 (2.6)	2.5 (2.8)	2.7 (2.9)	2.7 (2.9)	2.5 (2.8)	2.3 (2.5)	2.2 (2.2)	2.0 (1.8)
Real GDP (year-over-year percentage change)	2.5 (2.5)	2.0 (2.1)	1.0 (1.1)	0.8 (0.7)	0.7 (0.7)	1.4 (1.5)	2.1 (2.3)	2.2 (2.7)	2.5 (2.8)	2.6 (2.8)	2.5 (2.8)	2.4 (2.6)	2.2 (2.3)
Core inflation (year-over-year percentage change)	2.2 (2.2)	2.2 (2.2)	2.2 (2.2)	2.2 (2.1)	2.1 (2.0)	2.1 (2.0)	2.1 (1.9)	2.0 (1.8)	2.0 (1.9)	2.0 (1.9)	2.0 (2.0)	2.0 (2.0)	2.0 (2.0)
Total CPI (year-over-year percentage change)	2.0 (2.0)	1.0 (1.0)	1.0 (0.9)	1.2 (1.2)	1.4 (1.4)	1.6 (2.1)	1.5 (1.9)	1.4 (1.8)	1.6 (1.9)	2.0 (1.9)	2.0 (2.0)	2.0 (2.0)	2.0 (2.0)

a. Numbers in parentheses are from the projection in the previous *Report*. Assumptions for the price for crude oil are based on a recent average of spot prices.

Source: Bank of Canada Monetary Policy Report, October 2015, pp. 1, 14.

35.0 Reference: Exhibit B-1, Appendix B – Evidence of Mr. James M. Coyne, Section III, A – Summary of Current Economic and Capital Market Conditions, p. 14, footnote 17

Financial System Review

In his direct testimony, Mr. Coyne referenced a Bank of Canada publication and summarizes the Bank's findings as follows:

> [Mr. Coyne] finds that overall risk to financial stability in Canada has risen, but the resilience of the financial system continues to improve… [He] projects a modest pickup in global economic growth for 2015 and 2016, as investor confidence increases and consumers and businesses realize the benefits of recent deleveraging… [T]he Bank has identified three such system vulnerabilities which may pose risks for the Canadian economy … [one being] the elevated level of household indebtedness…The Bank goes on to identify the four key risks to the Canadian financial system … [the first being] the potential for a broad-based decline in employment and incomes of Canadians reducing the ability of highly-indebted households to service debts…

35.1 Footnote 17 did not include the name of the Bank of Canada publication. Would Mr. Coyne confirm that the name of the publication is "Financial System Review, June 2015"? If not confirmed, please provide the reference name of the publication Mr. Coyne made reference to.

<u>Response:</u>

Not exactly. The footnoted source was a press release dated, June 11, 2015, titled: "Bank of Canada says risk to financial stability is slightly higher, but system is more resilient." The press release provided a summary of the biannual Financial System Review issued in June 2015.

35.2 Assuming that the publication is the Financial System Review (FSR), would Mr. Coyne agree that the focus of the FSR is an assessment of the downside risks rather than the most likely future path for the financial system?

<u>Response:</u>

The publication was not the FSR referenced in the question, but instead was a news release summarizing the referenced report. Mr. Coyne notes that the cited news release indicates that "[t]he FSR is intended to raise awareness of the key vulnerabilities, possible triggers and risks to the financial system."

35.3 On page 1 in the Overview section of the FSR, the Bank states that "global economic growth is expected to strengthen over the course of 2015 and in 2016." Mr. Coyne describes that the Bank of Canada projects a modest pickup in global economic growth for 2015 and 2016. Is the adjective "modest" Mr. Coyne's own choice of word?

Response:

No. Mr. Coyne used the word "modest" since he had seen the economic growth characterized in that way by the Bank of Canada in its Financial System Review, issued December 2014, p. 1. The passage reads:

> *A modest pickup in global economic growth is expected in 2015 and 2016 as the headwinds coming from private and public deleveraging, as well as the uncertainty around future conditions, gradually diminish. Prospects are, however, uneven across the major economies. The U.S. economy has clearly strengthened and is expected to lead the improvement in global economic growth. In contrast, growth in much of the rest of the world will continue to face considerable challenges, leading authorities in some regions to deploy further policy stimulus.*

36.0 Reference: Exhibit B-1, Appendix B – Evidence of Mr. James M. Coyne, Section III, C – Integration of Canada and US Capital Markets, p. 28

Integration of Canada and US Capital Markets

On page 28 of Appendix B, Mr. Coyne states that:

> …from a business risk perspective, including overall business environment and competitiveness, Canada and the U.S. are ranked closely when compared against other developed and developing countries. Based on these macroeconomic indicators, there are no fundamental dissimilarities between Canada and the U.S. (i.e., in terms of economic growth, inflation, unemployment, or government bond yields) that would cause a reasonable investor to have a materially different return expectation for a group of comparably situated utilities in the two countries.

36.1 Where possible, please provide the residency of the investors of the major Canadian proxy companies used in Mr. Coyne's evidence. Please categorize the residency according to: (a) Canadian; (b) US; and (c) others.

Response:

The below information provides the percentage ownership by country of institutional owners and insiders. Concentric is unable to provide data on total holdings by country since individual shareholder residency information is not available publicly. The institutional and insider information is provided below:

% Ownership	Canadian	U.S.	Others
Canadian Utilities Ltd.	91.7%	4.2%	4.1%
Emera, Inc.	77.0%	17.0%	6.0%
Enbridge Inc.	45.3%	46.1%	8.6%
Fortis Inc.	80.0%	11.7%	8.3%
Valener Inc.	68.9%	24.5%	6.6%

Source: Bloomberg PCT_GEO_OWNERSHIP

36.2 Where possible, please provide the residency of the investors of the major US proxy companies used in Mr. Coyne's evidence. Please categorize the residency according to: (a) Canadian; (b) US; and (c) others.

Response:

Please refer to the response to BCUC IR 1.36.1 regarding the availability of total share holdings by country. The institutional and insider share ownership by country for the U.S. proxy group is provided below:

% Ownership	Canadian	U.S.	Others
Atmos Energy Corporation	.5%	85.8%	13.7%
New Jersey Resources Corporation	.5%	93.0%	6.5%
Northwest Natural Corporation	.5%	93.2%	6.3%
Piedmont Natural Gas Company, Inc.	.4%	93.2%	6.4%
South Jersey Industries, Inc.	.3%	95.9%	3.8%
Southwest Gas Corporation	.6%	93.9%	5.5%
WGL Holdings, Inc.	.9%	91.6%	7.5%

Source: Bloomberg PCT_GEO_OWNERSHIP

37.0 Reference: Exhibit B-1, Appendix B – Evidence of Mr. James M. Coyne, Section III, B – Changes in Capital Markets since 2012, pp. 23; Section V, D – Methods Used to Determine FEI's Cost of Equity, 2. Discounted Cash Flow Market ("DCF"), p. 59

Market return indicators

Table 3 at page 23 indicates that, as of August 2015, the long term growth rate on the TSX composite is 13.82 percent and that the long term growth rate for the TSX is 60 14.47 percent. The corresponding figures in June 2012 were far lower at 3.20 percent and 3.01 percent. The earnings in 2015 were modestly higher than in 2012. The Table also indicates that the dividend yield on the TSX in August 2015 was 3.13 percent. At page 59, Mr. Coyne provides a nominal GDP growth estimate for Canada of 3.94 percent.

37.1 Please explain in more detail the source and meaning of the TSX Composite and TSX 60 long-term growth rates shown in Table 3. Is the growth rate historical or forward looking?

Response:

The long-term growth rates shown in Table 3 are forward-looking. Both the 2012 and 2015 growth rates, referenced in this question, are the estimated compound annual growth rates over the company's next three to five year business cycle. These growth rates are derived from a forward- looking earnings analysis for each company. Growth rates are aggregated to reflect the growth in the index by the number of shares the constituent represents within the index.

37.1.1 If the growth rates are forward looking, please provide Mr. Coyne's assessment of the reasonableness of these long term growth rates of approximately 14 percent.

Response:

These growth rates are higher than his independent calculation of the weighted S&P/TSX composite growth rate at Exhibit JMC-4 Schedule 1, where Mr. Coyne calculates an expected market weighted growth rate of 10.02 percent. Differences between the two calculations have arisen due to the differing weighting methodologies employed by Mr. Coyne and Bloomberg. Though 14 percent is higher than Mr. Coyne has estimated based on his available data, equity markets have shown a strong resurgence since the lows experienced in 2009, (even though

2015 has seen some reversal of these gains); and 14 percent growth for the S&P/TSX is consistent with the observed resurgence in equity markets.

37.2 Please confirm that if the TSX earnings were to grow at a similar rate as nominal GDP then the total return would approximate 3.13 percent plus 3.94 percent, or 7.07 percent, assuming the P/E ratio and dividend payout ratio were unchanged.

Response:

Mr. Coyne confirms that if earnings were to grow at a similar rate as nominal GDP then the total return would approximate 3.13 percent plus 3.94 percent, or 7.07 percent, with one caveat. The return would be slightly higher to account for ½ year of dividend growth, i.e. 3.13 x (1 + ½ g) + g; or (3.13 x 1.0197) + 3.94 = 7.13 percent. However, as Mr. Coyne's evidence clearly demonstrates the TSX long term growth rate is 13.82 percent (as reported by Bloomberg at the end of August 2015 for the next three to five years) and not 3.94 percent, as postulated by the author.

38.0 Reference: Exhibit B-1, Appendix B – Evidence of Mr. James M. Coyne, Section III, C – Integration of Canada and US Capital Markets, p. 26; Exhibit JMC-2, Canadian and US Macroeconomic Factors

Achieved returns of utilities versus the TSX

Mr. Coyne's data indicates that over the past 25 years the TSX market return averaged 9.31 percent and that over the past ten years it averaged a very similar 9.29 percent while the return for the TSX utilities segment over the past ten years averaged somewhat higher at 9.69 percent

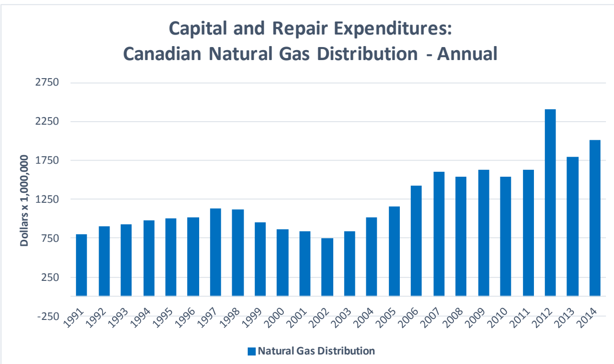
38.1 Please provide Mr. Coyne's views to the interpretation of this result including whether or not it might indicate that awarded utility returns may have over-compensated utility investors in comparison to the market return.

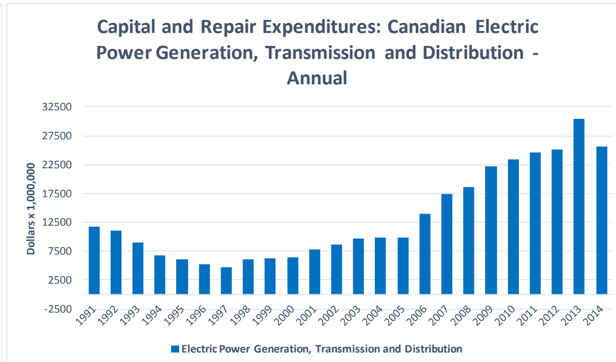
Response:

The companies in the TSX Utilities index, as illustrated below, represent a fairly broad exposure to the utilities sector, including a combination of electric, natural gas, power generation, retail and diversified energy service companies. These companies have a mix of both regulated and non-regulated operations.

S&P/TSX Composite Utilities Sector Index	
As of 12/3/2015	
12 Members:	
INE CT Equity	Innergex Renewable Energy Inc
CPX CT Equity	Capital Power Corp
BEP-U CT Equity	Brookfield Renewable Energy Partners LP/
ACO/X CT Equity	Atco Ltd/Canada
CU CT Equity	Canadian Utilities Ltd
FTS CT Equity	Fortis Inc/Canada
SPB CT Equity	Superior Plus Corp
NPI CT Equity	Northland Power Inc
AQN CT Equity	Algonquin Power & Utilities Corp
TA CT Equity	TransAlta Corp
EMA CT Equity	Emera Inc
JE CT Equity	Just Energy Group Inc

Further, allowed returns for utilities on book equity are different than the market returns experienced by investors in publicly traded equities. Allowed returns translate to earnings, and earnings drive stock price appreciation and dividends, but there is not a perfect correlation. It should also be recognized that the utility industry has been engaged in a period of significant capital investment, which contributes to earnings growth and share appreciation. For example, the figures below illustrate the growth in capital investment for the major Canadian investor-owned gas and electric utilities.





According to regulatory theorists, James C. Bonbright, regulated utilities that receive fair returns are expected to command substantial premiums over their book values or rate base values except in periods of a seriously depressed stock market. Specifically, Dr. Bonbright states:

> *It follows that the common stocks of public utilities which actually succeed in earning a "fair rate of return" as derived by a cost-of-capital technique can be expected to command substantial premiums over their book values or rate-base values except in periods of a seriously depressed stock market – premiums well in excess of any customary allowance for the necessary underpricing of new stock offerings. And the question arises whether the prevalence of these excess premiums is persuasive evidence of a corporate earnings power higher than enough to give adequate assurance of continue d corporate ability to attract the desire amounts of new capital on terms that do not impair the integrity of the existing capital.*
>
> *In my opinion, the answer to this question is in the negative. Regulation is simply powerless to assure the purchasers of public utility equities that future corporate earnings will suffice to maintain market prices on a par with book values or with any other dollar figure. Lacking this power, regulation wisely concedes to the public utility industries opportunities for corporate earnings liberal enough to bring to substantial market premiums the stocks of those well-managed companies that actually succeed in realizing these earnings fairly continuously. But while the allowance of a rate of return, during periods of prosperity, liberal enough to let utility equities command substantial premiums over their book values seems to me to be called for in the interest of long-run corporate ability to meet capital requirements, the question what constitutes a proper degree of liberality has not yet received a convincing answer. Indeed, I doubt whether a conclusive answer can ever be found under such an indefinite standard of a fair rate of*

> *return as that of a flexible rate designed to rise and fall with changes in anticipated rates of income necessary to induce new investments of equity capital.*[45]

Due to these factors, one could not make a determination from the returns on TSX utilities as to whether allowed returns were compensatory, nor could a determination be made as to what, if any, the appropriate adjustment to allowed returns would be. As Dr. Bonbright generally states, in his seminal work, Principles of Public Utility Rates, any adjustment to the technique of determining a fair return that incorporates an adjustment for share premiums would result in "harmful, uneconomic shifts in public utility rate levels"[46] and that it is doubtful that a conclusive answer can be found to design a rate "to rise and fall with changes in the anticipated rates of income necessary to induce new investments of equity capital."[47] Mr. Coyne concurs with the professional opinion of Dr. Bonbright and does not believe that high utility share premiums, relative to the market, indicate that awarded utility returns have over-compensated utility investors.

---

[45] Bonbright, James C., Principles of Public Utility Rates. New York, Columbia University Press, 1961, page 255-256.
[46] Ibid at 255.
[47] Ibid at 256.

39.0 Reference: Exhibit B-1, Appendix B – Evidence of Mr. James M. Coyne, Section V, D – Methods Used to Determine FEI's Cost of Equity, 2. Discounted Cash Flow Market ("DCF"), p. 60

Flotation cost

Mr. Coyne notes that the adjustment for flotation costs and financial flexibility compensates the equity holder for the costs associated with the sale of new issues of common equity.

39.1 Please explain if this cost is also incurred in regards to retained earnings or only in regards to the cumulative amount of equity issued.

Response:

The adjustment for flotation costs and financial flexibility are recovered by an adjustment to the equity return applied to all common equity, inclusive of retained earnings, regardless of whether equity issuances are planned. They are applied to retained earnings and not solely to the cumulative amount of equity issued to reflect the permanent reduction of capital associated with past issuance costs. With respect to flotation costs, equity investors are unable to earn a return on the portion of their capital paid out as flotation costs on an ongoing and indefinite basis. As such, it is appropriate to provide an adjustment for each dollar earned by the company whether it is derived in connection with an equity issuance or whether it stems from the earnings generated and retained in the business from past equity issuances. Though flotation costs are incurred as a result of equity issuances, they are not capitalized and amortized because equity has an indefinite life and will continue to benefit shareholders indefinitely. Rather than ask shareholders to pay for issuance costs at the time of issue that will benefit future generations of shareholders, a flotation adjustment is made to the authorized return thereby allowing shareholders to ratably recover the costs of equity issuances indefinitely. The adjustment must be applied to the entire equity balance to recover the costs of flotation on an ongoing basis.[48] An adder of 50 bps to the allowed equity return is a common adjustment among regulators in Canada,[49] and in Mr. Coyne's opinion is generally appropriate to provide a cushion to maintain financial integrity during periods of unexpected market volatility and to recover past issuance costs.

---

48 See Morin, New Regulatory Finance (2006) at 329.

49 A 50 bps flotation adjustment was allowed by the BCUC in its May 2013 GCOC Decision (p. 80); the OEB in its December 2009 Decision EB-2009-0084 on the Cost of Capital for Ontario's Regulated Utilities (p.37); the AUC in its March 2015, Generic Cost of Capital Decision 2191-D01-2015 (p.30); the Régie in its November 2011 Decision D-2011-182, R-3752-2011 Phase 2, allowed 30 to 40 bps for flotation, 25 to 50 bps for the CAPM model, and 25 to 40 bps to adjust for credit spreads (p.27); the Newfoundland & Labrador Board of Commissioners of Public Utilities in its 2013 Decision P.U. 13 (p. 21). This list is not intended to be all-inclusive and there may be other Canadian jurisdictions that have allowed 50 bps for flotation and financing flexibility.

39.2 In Mr. Coyne's view, does a 50 basis point allowance exceed the actual cost incurred?

Response:

It is Mr. Coyne's understanding that the 50 basis point flotation and financing flexibility adjustment is to account for flotation costs and to provide a cushion for unanticipated capital market conditions. Flotation costs are company and market specific, but would typically require an adjustment of between 20 to 30 bps, generally derived by the following formula.

$$flot\ Adj = \left[{}^{D}\!/_{P}\ (1-f)+g\right]-\left[{}^{D}\!/_{P}+g\right]$$

The remainder provides a financial cushion against unexpected market volatility and, in Mr. Coyne's is generally adequate for that purpose.

39.3 Please explain if the need for financial flexibility is related to the extent to which utility equity is raised at or well above its book value per share.

Response:

As discussed in Mr. Coyne's response to BCUC IR 1.39.2, the adjustment for financial flexibility is designed to provide a financial cushion for unexpected market conditions, but it also provides the utility with some moderation of the financial effects of applying a market-based return to its smaller book equity.

40.0 Reference: Exhibit B-1, Appendix B – Evidence of Mr. James M. Coyne, pp. 10, 11, 34, 53–56

Analyst growth estimates

Mr. Coyne submits at page 10 and 11 that the Fair Return Standard "requires an examination of the required return by investors in like-risked enterprises" and that this return is referred to as an "opportunity cost." At page 34, he submits that "the key consideration is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, and the subject company (in the context of the proxy group) in particular."

In this regard, Mr. Coyne provided the DCF test which calculated investor return expectations based on analyst growth forecasts.

In the GCOC Stage 1 Decision, the Panel indicated that it "expects that future hearings will be informed of the latest research on bias in analyst's reports on the utilities sector."[50]

Beginning at page 53, Mr. Coyne addressed the topic of the reliability of analyst growth rates and cited a 1986 article on the topic and a second article from 1988 (including also a 2004 update of that article) and an article from 1992 in support of the use of analyst growth estimates. Mr. Coyne noted that more recent full disclosure regulations have reduced analyst forecast bias as noted in a 2010 article.

In regards to investors' views of the financial markets, in the GCOC Stage 1 Decision, the Panel discussed the use of pension analyst market return expectations as a robustness test and did "not accept the assertion that pension actuarial expectations are conservatively biased" and found that "this robustness test is indeed helpful in assessing the risk premium."[51]

40.1 Please confirm that FEI and Mr. Coyne have not provided quantitative evidence on the accuracy or any directional bias in utility analyst earnings growth forecast in the past or, particularly, in recent years.

<u>Response:</u>

As noted above, the Commission Panel did indicate that future hearings would be informed by the latest research, but the Panel also found:

[50] GCOC Stage 1, Decision dated May 10, 2013, p. 71.
[51] GCOC Stage 1, Decision dated May 10, 2013, p. 61.

The expert testimony at this time does not, however, convince the Panel that an adjustment for analyst bias should be made.[52]

The Commission had also considered this issue in its 2009 Decision for Terasen, and found:

As for the two most commonly used approaches, the Commission Panel finds that the DCF approach has the more appeal in that it is based on a sound theoretical base, it is forward looking and can be utility specific. The Commission Panel has considered the submission of the JIESC concerning "upward bias" of analysts' estimates and considers that no allegations of upward bias have been leveled against utility analysts and that Value Line estimates will be free from any suggestion of upward bias. Accordingly the Commission Panel will not give any weight to suggestions of analyst bias.[53]

Mr. Coyne confirms that he has not provided quantitative evidence on the accuracy or any directional bias in utility analyst earnings growth forecasts in recent years. In addition to the qualitative evidence he has cited in his testimony, he is of the view that If there were significant bias among consensus investment analysts, we would note a significant difference between Value Line growth estimates and the consensus forecasts, since Value Line is an independent analyst with no incentive to understate or overstate growth prospects for the companies it covers. This same logic seems to underscore the Commission's logic in its 2009 decision. Turning to the evidence provided by Mr. Coyne in this proceeding, he considers Exhibit JMC-5 responsive. The average Value Line EPS growth estimates for the companies in the U.S. proxy group (Value line does not provide similar coverage for the Canadian utilities) is 5.5%, in contrast to 5.5% from Zacks, 5.62% from SNL, and 5.5% from First Call. Due to the close proximity of these growth projections, these data would certainly not indicate the presence of analyst bias in relation to the independent Value Line projections. As such, there is no evident bias in the consensus analysts' growth estimates as compared to the independent estimates developed by Value Line.

40.2 In light of the Panel's comments on the helpfulness of pension return estimates and of the fact that pension return estimates of publicly traded companies and of public pension plans are disclosed, please explain why FEI and Mr. Coyne has not provided any evidence in this regard.

[52] GCOC Stage 1, Decision dated May 10, 2013, p. 71.
[53] BCUC, Terasen Gas Inc., Return on Equity and Capital Structure, Decision December 16, 2009, p. 45.

Response:

Mr. Coyne has not provided pension return estimates of publicly traded companies or of public pension plans and does not believe it is appropriate to do so for several reasons. First, pension funds have very different business objectives and risk profiles than that of a corporation or a utility. A pension fund is focused on optimizing value of its assets and providing stable cash flows to fulfill funding obligations within specific risk thresholds. Pension funds may have a portfolio of assets that includes hedge fund investments, short positions, substantial bond portfolios, derivatives, real estate, etc. These portfolios are not equivalent to the equity in a corporation or utility.

The other problem is that forward looking pension return estimates do not provide real information on expected returns but rather are the product of asset allocation and contribution policy. Pension plan funding must be sufficient to cover the growth in existing liabilities as well as cover the value of any new benefit accruals and any prior funding shortfalls of the Plan. Funding shortfalls can result in significant financial hardship for the Company or Pension Plan. The Plan must rely on contributions and returns to achieve its required funding level and it is not in the Plan Administrator's interest to provide anything but a very conservative estimate of future expected returns to ensure that funding contributions are adequate to support the funding requirements of the Plan. According to a recent article, "What is a pension plan's return objective? Well, it's not ELTRA" published by Bob Collie,[54] June 4, 2014, Mr. Collie states:

> *"In practice, the actual target return from the investments is derived in conjunction with a funding (contribution) policy. And it is generally implicit. That is to say, a decision on asset allocation policy is made based on expected contributions (or surplus) rather than directly based on expected return. But the return target is there nonetheless – typically somewhere around 5-8% in our experience."* [emphasis added]

The author suggests pension plan return expectations are therefore derived to fill the funding gap between contributions and the funding requirement.

Taking the specific example of the Ontario Teachers' Pension Plan, the Fund Annual Report indicates the expected growth in fund assets, before contributions or expenses, is 9.5 percent between 2014 and 2015. The Annual Report reveals that it has earned an average return of 12.24 percent on its Plan assets over the last five years. This is especially noteworthy since bonds and real rate products make up approximately 43% of the total plan assets (see p. 50 of 2014 Annual Report).

[54] Bob Collie is chief research strategist for Russell Investments' Americas Institutional business. He is responsible for the strategic advice delivered to the various parts of Russell's institutional client base, working with the manager research team, product groups and other research efforts across Russell. Bob joined Russell in 1994 as a consultant in the U.K., and has worked for Russell in the U.S. since 2002. He previously worked for William M. Mercer's actuarial and investment practices.

Though it may be tempting to use a Pension Plan's published expected return as a source of low risk investment return expectations, the Commission should refrain from doing so, as the published forward-looking return information represents one component of a comprehensive funding plan which is derived from both funding policy and return expectations. In sum, pension fund assets are not similar to utility assets, return expectations are not comparable, and comparisons provide no practical benefit for regulatory determination of allowed equity returns.

Please refer to Attachment 40.2.

In addition, FEI submits that it has not provided any evidence on the pension return estimates of publicly traded companies and of public pension plans as the response to BCUC IR 1.3.2 explains how pension return estimates are not relevant for assessing a utility's cost of capital. Further, it is understood that the "pension return estimates of publicly traded companies and of public pension plans" is referring to the Expected Return on Assets (EROA) of such public entities, as that is the only publicly available pension return estimate information. Each public entities' EROA will be based on the specifics of the asset mix of each defined benefit pension plan, as well as the different duration of each plan (the average length of time over which the plan's cash flows are payable). As such, not only are there challenges in comparing the EROA amongst each of these public entities without understanding the allocation to each of the investments, the EROA bears minimal relevance in determining FEI's ROE. As such, FEI has not provided any evidence on the pension return estimates of publicly traded companies and of public pension plans.

FEI interprets the "pension return estimates of publicly traded companies and of public pension plans" as referring to the Expected Return on Assets (EROA) of such public entities, as that is the only publicly available pension return estimate information. Each public entities' EROA will be based on the specifics of the asset mix of each defined benefit pension plan, as well as the different duration of each plan (the average length of time over which the plan's cash flows are payable). As such, not only are there challenges in comparing the EROA amongst each of these public entities without understanding the allocation to each of the investments, the EROA bears minimal relevance in determining FEI's ROE. Please see the response to BCUC IR 1.3.2 for further explanation.

40.3 Is Mr. Coyne aware of any other available sources of investor market or utility return expectations that could be used to ensure that the Commission's findings reasonably reflect opportunity costs and investors views of the future returns that can reasonably expected from investments in the equity markets or in equities with risks similar to utility stocks in particular?

Response:

One clear indication of investor expectations regarding utility returns is that set by allowed returns from regulatory commissions. These are transparent indicators that form investor expectations, and when viewed broadly, avoid the problem of circularity. This is evidenced by the attached report from Goldman Sachs which clearly focuses on the both the trend and levels of allowed returns by jurisdiction in the U.S. Please refer to Attachment 40.3, Exhibits 4, 5, 6 on pp. 3-5. Other sources of market or utility return expectations can be found in Value Line's forward earnings projections, investment bank equity analyst reports, and occasionally in credit rating analyst reports.

41.0 Reference: Exhibit B-1, Appendix B – Evidence of Mr. James M. Coyne, Section V, D – Methods Used to Determine FEI's Cost of Equity, 1. Capital Asset Pricing Model, p. 41, fn. 63

Spread between 30-year and 10-year risk-free debt yields

Mr. Coyne provides an average historical spread of 71 basis points and indicates that the historical period used was from August 1, 2015 to August 31, 2015.

41.1 Please provide the average spread in each of the latest 12 months available and indicate why the data from only the most recent month should be used, if that is Mr. Coyne's view.

Response:

The average spread in each of the latest 12 months available is provided below. Mr. Coyne used the most recent data available to calculate the spread in keeping with normal BCUC convention for developing a forecast 30-year government bond yield. In Mr. Coyne's view, the calculated bond spread should be recent and finds the BCUC precedent reasonable.

Year	Month	GCAN30YR Index	GCAN10YR Index	GCAN30YR - GCAN10YR Index Spread
2014	12	2.40	1.86	0.54
2015	1	2.11	1.54	0.57
2015	2	2.01	1.39	0.62
2015	3	2.05	1.42	0.63
2015	4	2.04	1.41	0.63
2015	5	2.34	1.74	0.59
2015	6	2.38	1.78	0.59
2015	7	2.24	1.58	0.66
2015	8	2.11	1.40	0.71
2015	9	2.24	1.48	0.76
2015	10	2.26	1.47	0.80
2015	11	2.35	1.64	0.71

Source: Bloomberg

42.0 Reference: Exhibit B-1, Appendix B – Evidence of Mr. James M. Coyne, Section V, D – Methods Used to Determine FEI's Cost of Equity, 2. Discounted Cash Flow Market ("DCF"), p. 48

CAPM equity risk premium results

Mr. Coyne's Capital Asset Pricing Model (CAPM) results summarized at Table 7 placed a 50 percent weighting on a forward-looking market risk premium approach to the CAPM which "used the DCF methodology to determine the implied expected market return."

In the GCOC Stage 1 Decision, the Panel indicated at page 66 indicated that it was not persuaded that the CAPM model "extensions" or adjustments presented in that proceeding were valid and placed no weight on them.[55]

42.1 Please confirm that My Coyne's unadjusted CAPM Market Risk Premium (MRP), based on Canadian historical data, is 5.6 percent and is 7.0 percent based on US data and that the average of these two is 6.3 percent.

<u>Response:</u>

Confirmed.

42.1.1 Is Mr. Coyne's forward-looking market risk premium approach a CAPM approach as that term has traditionally been used by the Commission?

<u>Response:</u>

The Commission panel found merit in this approach in the 2013 GCOC. In its decision, the Panel observed:

In a second robustness test, Dr. Booth uses the DCF model to estimate an expected return on the entire market. The resulting estimate is 9.3 percent and Dr. Booth notes that this is very close to the expectation held by FEI's own actuaries. (Exhibit C6-12, Booth Evidence, p. 86) This is a forward looking estimate of the market return so that a forward looking risk free investment can be used to compute the risk premium. Since Dr. Booth concludes in his first robustness test that a 9 percent market return implies a 6.2 percent risk premium, his estimates of 9.3 percent for the market suggests a market risk premium of about 6.5 percent. FBCU argue that the DCF cannot be used to assess the market as a whole. (FBCU Reply, pp. 29-30) The Panel disagrees with this assertion.

[55] GCOC Stage 1, Decision dated May 10, 2013, p. 66.

Although the model is typically illustrated and applied to a single company, the logic of investors setting prices based on expected cash flows applies equally to a mutual fund or portfolio of shares. The Panel, therefore, does not agree that this approach cannot be taken to estimate the expected return on the market. The Panel therefore finds the DCF based estimate of forward-looking market returns to be helpful as a check.[56]

Mr. Coyne is offering similar evidence for the Commission's consideration that provides a forward-looking risk premium directly calculated by current market information. He also tested this forward looking market risk premium with a regression analysis factoring in the relationship to bond yields. As Mr. Coyne explains in his testimony, a historical average based on nearly 100 years of data cannot respond to the dramatic lowering of interest rates we have experienced in the last decade. Mr. Coyne believes his regression analysis provides clear evidence of the inverse nature of the risk premium to risk free bond yields; further the market implied risk premium derived from current market information provides the Commission with sufficient basis to judge the validity of Mr. Coyne's estimates of the CAPM market risk premium.

42.2 Please confirm that if a MRP of 6.3 percent is used in combination with Mr. Coyne's recommended risk free rate of 3.68 percent, then this would imply that he indicated required return on equity markets is 10.0 percent.

Response:

Mr. Coyne confirms that if a MRP of 6.3 percent is used in combination with the risk free rate of 3.68 percent, then this would imply that the indicated required return on equity markets is approximately 10 percent.

42.2.1 Does Mr. Coyne believe that it is reasonable for the average Canadian equity investor in 2015 or 2016 to expect an equity return of 10.0 percent?

[56] GCOC Stage 1, Decision dated May 10, 2013, pp. 61-62.

Response:

Yes, the market data supports this expectation. As indicated on Exhibit JMC-2, the S&P/TSX has generated returns in excess of 10.0 percent since 2013. According to the dividend yield and long term growth rate data for the S&P/TSX Composite and the S&P/TSX 60 in Table 3, on page 23 of Mr. Coyne's testimony, when used as inputs to a market DCF calculation, yields a return on investment in the S&P/TSX Composite or the S&P/TSX 60 of 17.2 percent and 17.8 percent, respectively. Further, Mr. Coyne's overall market DCF calculation on the S&P/TSX Index (shown at Exhibit JMC-4, Schedule 1) shows that a return on the market of 13.46 percent is indicated by the underlying market data. Collectively, these data would support a 10 percent equity return expectation.

42.3 Please confirm that using Mr. Coyne's average historical US MRP of 7.0 percent for Table 7 combined with his US risk free rate of 4.29 percent from Table 5 implies that US investors should expect an equity market return of 11.3 percent.

Response:

Mr. Coyne confirms that if a U.S. MRP of 7.0 percent is used in combination with the risk free rate of 4.29 percent, then this would imply that the indicated required return on U.S. equity markets is approximately 11.3 percent.

42.3.1 Does Mr. Coyne believe that it is reasonable for the average investor to expect US equity markets to return 11.3 percent?

Response:

Yes. As indicated on Exhibit JMC-2, the S&P 500 has generated returns in excess of 10 percent for the past three years. According to Mr. Coyne's overall market DCF calculation on the S&P 500 Index (shown at Exhibit JMC-4, Schedule 2) shows that a return on the market of 12.37 percent is indicated by the underlying market data. Therefore, these data corroborate a market return of greater than 11.3 percent

43.0 Reference: Exhibit B-1, Appendix B – Evidence of Mr. James M. Coyne, Section III, C – Integration of Canada and US Capital Markets, p. 25

Comparability of US risks and returns

Mr. Coyne discusses a report that "suggests that from a business investment perspective, Canada and the U.S. are highly comparable in a global context."

43.1 Please confirm that the report was not focused on regulated utilities and does not address the comparability of the risk of utility investments in Canada versus the US after considering the impact of all risks including the regulatory framework and the ability to recover costs and earn returns.

Response:

Confirmed.

44.0 Reference: Exhibit B-1, Appendix B - Evidence of Mr. James M. Coyne, Table 18, pp. 94, 95

Proxy group credit metrics

Mr. Coyne provides the credit metrics for Fortis Inc. which he notes is FEI's parent and indicates that Fortis Inc.'s credit metrics are weaker than FEI's but explains that there are many elements at a Holdco level that affect earnings, debt levels, cash flows and credit metrics.

44.1 Please explain the extent to which Fortis Inc. can be considered to be a relatively pure-play regulated utility.

Response:

Mr. Coyne addresses this question, in part, in his testimony on page 31, lines 7-10, where he states:

I have included Fortis Inc. among the proxy group companies, which one could argue might introduce some circularity into the analysis, but given the relatively pure play nature of Fortis Inc. (93 percent of assets dedicated to utility service), I have decided to include Fortis Inc.

While a pure play publicly traded utility is generally unavailable, Fortis Inc. is reasonably close.

44.2 Please confirm that at the end of 2014, Fortis Inc. had a goodwill asset of $3,732 million and total equity of $8,691 million.

Response:

Confirmed.

44.3 Please explain if the existence of goodwill contributes to weaker credit metrics for Fortis Inc. than would otherwise be the case in the absence of goodwill.

Response:

The response will be dependent on several considerations, including how the goodwill and the related acquisition is financed by Fortis Inc. Assuming the goodwill is fully financed by equity, the existence of goodwill does not contribute to weaker credit metrics for Fortis Inc. and actually improves Fortis Inc.'s debt to capital ratio since it increases equity and thereby reduces the proportion of debt in total capital. The cash flow metrics would be unaffected by the existence of goodwill with the exception of the EBIT/interest ratio. The ratio would be slightly weaker to the extent that goodwill assets are amortized, but it is Mr. Coyne's understanding that Fortis Inc.'s goodwill assets are not amortized, but subject to an annual impairment test.

44.4 Please comment on the ability of a Fortis Inc. to achieve an A-credit rating and attract debt capital despite the weak credit metrics indicated in Table 18.

Response:

As Mr. Coyne has indicated in his Business Risk Appendix A to his Direct Testimony (page A-16), S&P commented on the significant financial risk of Fortis Inc. and its willingness to continue to assign it an A- credit rating in consideration of the revenue and cash flow stability of Fortis' operations. Specifically S&P stated:

> *We expect Fortis' cash flows from the regulated utilities to remain very stable, a factor we believe is a key credit strength that offsets the company's high leverage. Regulated utility cash flow is primarily composed of a return of capital (depreciation) and a return on capital, both of which continue to experience limited volatility. Consolidated leverage is a function of the regulatory capital structure of the underlying utilities that generally follows levels regulation allows. We have assumed rate-base growth leads to corresponding growth in cash flow. We believe that the UNS addition would modestly improve Fortis' financial metrics. We forecast TEP, the company's largest provider of cash flow, to have an AFFO-to-total debt ratio of greater than 20%, compared with Fortis' 10%-11%. We forecast AFFO-to-total debt ratio for Fortis in the 12%-13% range in 2015 and 2016, improving to more than 13% in 2017. Based on our forecast, we have assessed the company's financial risk as significant.*[57]

In Mr. Coyne's opinion, Fortis is able to continue to achieve an A- credit rating because of its stable and predictable regulated cash flows and the prospects for growth and improvement in

[57] S&P Ratings Direct, Summary: Fortis Inc. (April 25, 2014).

financial metrics. Maintaining its A- credit rating will assist the Company in attracting debt and equity capital on favorable terms.

45.0 Reference: Exhibit B-1, p. 32

Automatic Adjustment Mechanism (AAM)

On page 32 of its Application, FEI states: "FEI respectfully submits that the Commission should suspend the application of the AAM in BC, instead reviewing the cost of capital for the benchmark utility in a three to five year time frame."

45.1 In the GCOC Stage 1 Decision, the AAM was reinstituted with the timing of its use to expire on December 31, 2015. The AAM's operation was subject to conditions and AAM was never triggered because the conditions were never met. Is FEI requesting that the Commission should not consider the use of <u>any</u> AAM when considering the return on equity for the benchmark utility or is FEI requesting that the AAM as designed in the 2012 GCOC Stage 1 proceeding should be suspended?

<u>Response:</u>

FEI believes that no single formula can capture all the changes facing a utility's cost of capital and that a formula driven ROE may yield a return that does not meet the Fair Return Standard. Therefore FEI respectfully requests that the Commission should suspend the use of an AAM formula in general (any AAM formula) and review the cost of capital for the benchmark utility in a 3 to 5 year time period.

However if the Commission denies FEI's request and decides to continue with an AAM, FEI submits that it should keep the AAM formula that was designed in the 2012 GCOC Stage 1 proceeding (the two factor model), and review the applicability of the AAM as part of the next cost of capital review for the benchmark utility.

Attachment 20.2

[redacted]

19.4 Please provide a table showing the assumptions and variables that underpin the reference case, assumptions used to mean factors that are not adjusted for any of the scenarios (including the reference scenario), and variables are factors that are adjusted.

Response:

The FEU provide the table below to show an example of the assumptions and variables underpinning the reference case forecast. This example shows the requested information for residential DHW in single family dwellings in the Lower Mainland, to demonstrate the level of detail involved in the models. The FEU are not able to provide a complete listing of all information for all variables and assumptions within the response time frame due to the large number of assumptions and variables by end use. Such a response would result in over 4,000 pages of information, take considerable time to prepare and be outsourced to our forecast modelling consultant. However, the forecast model has been designed in such a way that individual assumptions and variables can be examined fairly readily by the FEU.

The modeled estimate of the tertiary energy[6] requirement for DHW is built up from assumptions about the individual DHW end uses (clothes washing, dishwashing, showers, faucet use), which may vary by house type and over time because of differences in occupancy and the efficiency of the end use devices. Regionally, tertiary load will also vary somewhat depending on the average temperature of the ground, which affects water mains temperature. The consumption of natural gas for DHW per dwelling is a combination of tertiary load, efficiency of the DHW appliance, and gas share. Consumption per dwelling in each of the categories, which are also separated into existing, renovated, and new dwellings, is multiplied by the number of dwellings in each category, to estimate the total gas consumption for DHW in the dwellings. Total gas consumption in the base year for all end uses and dwellings in a region must ultimately calibrate to the FEU consumption figures for that rate class.

While the base year is the same for all of the scenarios, most of the values in the table can vary by scenario for the future milestone years. In fact, the values under Ref #2, Ref #3, and Ref #5 are the primary variables that were directly adjusted from one scenario to another, with other variables changing because they are calculated from those three. The totals in Ref #7 do not change, but there is some shifting between categories.

[6] Tertiary energy is defined as the useful energy delivered to accomplish the end use task; for example, for DHW it is the heat actually transferred into the water. Secondary energy for an end use is the energy delivered to the customer's home or business to fuel the end use appliance; for example, for DHW it is the energy content of the natural gas used by the water heater. For a natural gas water heater, secondary energy is tertiary energy plus the losses due to the efficiency of the water heater. Primary energy is the energy content of the natural gas that must come out of the ground in order to supply the ultimate end use, including all losses in between.

Ref #	Variable or Assumption?	Description	Dwelling Type	Value, 2011	Value, 2033	(Units)	Does it vary by scenario	Endogenous or exogenous?	Notes
1	Variable	Tertiary Load - the energy to do the DHW tasks in the home	Pre-2006 SFD, mainly gas heat	11,717	8,112	MJ	Yes, for milestones after the base year	Endogenous - back-calculated from the EUI and efficiency variables	2006 and later dwellings have higher occupancy, but also higher incidence of efficient clothes washers and dishwashers, according to the REUS. The occupancy difference assumption was not changed in the later milestone years, but the difference in appliance efficiency was assumed to disappear with time.
			2006 or later SFD, mainly gas heat	10,793	8,575	MJ			
			Pre-2006 SFD, mainly non-gas heat	11,717	8,112	MJ			
			2006 or later SFD, mainly non-gas heat	10,793	8,575	MJ			
2	Variable	Efficiency - the combustion efficiency of the appliance	Pre-2006 SFD, mainly gas heat	60%	64%	%	Yes, for milestones after the base year	Exogenous	2006 and later dwellings have higher incidence of tankless and condensing DHW, according to the REUS. Other dwellings were assumed to reach EF of 0.64 by the end of the forecast period, with 2006 and later staying at an average of 0.68. These efficiency gains varied by scenario.
			2006 or later SFD, mainly gas heat	68%	68%	%			
			Pre-2006 SFD, mainly non-gas heat	60%	64%	%			
			2006 or later SFD, mainly non-gas heat	68%	68%	%			
3	Variable	Gas Energy Utilization Index (EUI) - how much gas used by DHW if it is gas	Pre-2006 SFD, mainly gas heat	19,529	12,674	MJ	Yes, for milestones after the base year	Exogenous	Using FortisBC sales data, REUS data on the percentage of DHW supplied by gas, and assumptions (largely from the 2010 CPR) about how much energy is used by the different gas end uses, the base year values for gas EUI are adjusted to calibrate modeled gas consumption to match sales to the dwellings. Values in future milestones vary depending on assumptions about tertiary load and efficiency.
			2006 or later SFD, mainly gas heat	15,953	12,674	MJ			
			Pre-2006 SFD, mainly non-gas heat	19,529	12,674	MJ			
			2006 or later SFD, mainly non-gas heat	15,953	12,674	MJ			
4	Assumption	Saturation - what percentage of dwellings have this end use in any form	Pre-2006 SFD, mainly gas heat	100%	100%	%	No	Exogenous	All dwellings are assumed to have DHW. Saturations are not 100% for some of the other end uses. In general, we have not varied saturation by scenario.
			2006 or later SFD, mainly gas heat	100%	100%	%			
			Pre-2006 SFD, mainly non-gas heat	100%	100%	%			
			2006 or later SFD, mainly non-gas heat	100%	100%	%			
5	Variable	Gas Share - the percentage of energy used by the end use that is supplied by gas	Pre-2006 SFD, mainly gas heat	92%	92%	%	Yes, for milestones after the base year	Exogenous	The base year values are from the REUS. Base year values are the same for all scenarios. Gas share varies in future milestones in the different scenarios.
			2006 or later SFD, mainly gas heat	76%	76%	%			
			Pre-2006 SFD, mainly non-gas heat	69%	69%	%			
			2006 or later SFD, mainly non-gas heat	57%	57%	%			
6	Variable	Gas Use Per Unit - consumption of gas for DHW per dwelling, accounting for gas share	Pre-2006 SFD, mainly gas heat	18,025	11,698	MJ	Yes, for milestones after the base year	Endogenous - calculated from EUI * saturation * gas share	
			2006 or later SFD, mainly gas heat	12,193	9,687	MJ			
			Pre-2006 SFD, mainly non-gas heat	13,537	8,785	MJ			
			2006 or later SFD, mainly non-gas heat	9,157	7,275	MJ			
7	Variable	Number of units - dwellings in each category	Pre-1976 SFD, mainly gas heat	193,366	193,366	dwellings	Yes, for milestones after the base year	Exogenous	From FortisBC account totals, but divided up using REUS data. Existing dwellings, dwellings that undergo a major renovation, and new dwellings are tracked separately and can have different numbers for the above variables and assumptions, so the total consumption is not a simple multiple of Ref #6 times Ref #7. Total number of dwellings does not vary by scenario, but the split between dwellings that are primarily heated by gas and dwellings that use a different space heating fuel varies by scenario in the future milestone years.
			1976-2005 SFD, mainly gas heat	212,743	212,743	dwellings			
			2006 or later SFD, mainly gas heat	24,242	53,440	dwellings			
			Pre-1976 SFD, mainly non-gas heat	12,562	12,562	dwellings			
			1976-2005 SFD, mainly non-gas heat	13,820	13,820	dwellings			
			2006 or later SFD, mainly non-gas heat	5,967	13,153	dwellings			
8	Variable	Gas Reference Case - total consumption of gas for DHW in each category of dwellings	Pre-1976 SFD, mainly gas heat	3,485,456	2,262,061	GJ	Yes, for milestones after the base year	Endogenous	Calculated from multiplying the number of houses in each category (separating existing, renovated, and new) by the corresponding consumption for the end use. Base year consumption for all end uses for all dwelling types in a region must match the FortisBC data on gas sales to the residential rate class in that region.
			1976-2005 SFD, mainly gas heat	3,834,743	2,488,748	GJ			
			2006 or later SFD, mainly gas heat	295,584	463,559	GJ			
			Pre-1976 SFD, mainly non-gas heat	170,040	110,356	GJ			
			1976-2005 SFD, mainly non-gas heat	187,080	121,415	GJ			
			2006 or later SFD, mainly non-gas heat	54,634	85,681	GJ			

The table above is intended to illustrate the level of detail in the model. To list all the assumptions and variables in the reference case comprehensively, the table above would need to expand as follows:

- More of the details underlying the tertiary load and average efficiency estimates would be provided, such as the occupancy assumptions, percentage of high efficiency clothes washers, percentage of tankless and condensing DHW units, etc. Development of these estimates drew heavily on the REUS reports provided by FortisBC, but also used ICF Marbek's internal database of end use consumption information, incorporating data compiled from previous conservation potential studies.
- The table above would be replicated for 11 other end uses, each one treated somewhat differently
- The four milestones between 2011 and 2033 would be added (as additional columns)
- The existing, renovated, and new dwellings would be shown separately
- The table above shows information on only six dwelling types, condensed to four for some of the variables. There are 14 dwelling types in residential altogether.
- There are four other fuels in the residential model: electricity, other fossil, renewables, and district energy.
- There are five other regions.
- The comprehensive list of assumptions for the residential sector would therefore include four additional columns (for the other milestones) and would be 12 (end uses) x 3 (exist/reno/new) x 14/6 (dwelling types) x 5 (fuels) x 6 (regions) = approximately 2,500 pages long.
- The commercial and industrial models together would require approximately 1,900 pages of similar tables to the one above, but would also require a separate set of tables to describe how the consumption and numbers of accounts are divided up among the nearly 30 different rate classes that are tracked separately in the commercial and industrial sectors.

The assumptions above address only the LTRP portion of the model. The EEC portion of the model includes assumptions about the many energy efficiency measures that can be applied as part of energy efficiency programs, including their performance improvement, costs, current penetration, expected penetration under different program scenarios, and so forth. The EEC portion of the model relies heavily on the measure assumptions developed under the 2010 CPR study. The deliverables of that study provided detailed information on the assumptions used.

38.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Appendix B-3

End-Use Annual Demand Forecasting Scenario Descriptions

Appendix B-3 lists the assumptions and interpretation and change in variable value relative to the reference case.

38.1 Please provide a table showing for each variable the value in the reference case and the value in the scenario analysis. An example table is shown below for the residential sector. Please correct any incorrect values since some examples require some speculation as to what was meant in the original table. Please also provide similar tables for the commercial and industrial sectors.

Residential					
Variable	**Scenario**	**Assumption**	**Value**	**Action Taken**	**Cumulative Result**
Commodity Price plus Carbon Price	Reference			???	2031 UPC increase/decrease of...
	A	Low gas price, high carbon price	Gas: $8.17/GJ	1% decrease in growth of gas heat dwellings	
			Carbon: $6.00 (rounded from $5.92?)	1% of existing gas furnaces switch to alt fuel	
			Combined: $14.17/GJ	1% of existing gas DHW switch to alt fuel.	UPC decrease of...
	B	Moderate to high gas price, moderate carbon price	Gas: $12.03/GJ	2% reduction in new gas ht	
			Carbon: $3.00 (rounded from $2.96?)	2% of replacement ducted gas heat switch to gas	
			Combined: $15.03/GJ	2% of replacement non-gas DHW switch to gas	EUI decrease of ...
	C	Low gas price, low carbon price	Gas: $7.64/GJ	9% increase in gas hear	Increase in UPC of ...
			Carbon: $1.48/GJ	9% of existing non-gas heat replace with gas	
			Combined: not specified ($9.12/GJ?)	9% of eligible non-gas DHW replace	
	D	Moderate gas price, moderate carbon price	Gas: $10.04/GJ	2% increase in growth of new gas heat dwellings	
			Carbon: $2.22/GJ ($2.25?)	2% of replacement ducted gas heat switch to gas	UPC decrease of ...
			Combined: 12.29/GJ	gas DHW switch to gas	
Economic growth	Reference	???	???	???	???
	A	Strong –	no change to housing starts relative to reference case	???	???
	B				
	C				
	D				
Government Policy					
Renewable, thermal and energy efficiency					
Regional energy strategies					

Response:

Please refer to Attachment 38.1, which contains a live spreadsheet in the above format for each of the three sectors.

38.1.1 For each of the categories in the tables provided in response to the above question, please identify the key variables and whether they are endogenous or exogenous variables.

Response:

All of the variables in the tables in response to BCUC IR 1.38.1 are adjusted exogenously to the model and manually input into the workbooks that feed the model.

Residential					
Variable	**Scenario**	**Assumption**	**Value**	**Action Taken**	**Cumulative Result**
Commodity Price plus Carbon Price	Reference			No change from 2010 CPR assumptions other than updated base year; no fuel switching assumed	2031 UPC decrease of 19% relative to 2011
	A	Low gas price, high carbon price	Gas: $8.17/GJ	1% decrease in growth of gas heated dwellings	2031 UPC decrease of 0.6% relative to reference case
			Carbon: $6/GJ	1% of existing gas furnaces requiring replacement switch to non-gas fuel	
			Total: $14.17/GJ	1% of existing DHW units requiring replacement switch to non-gas fuel	
	B	Moderate to high gas price, moderate carbon price	Gas: $12.03/GJ	2% decrease in growth of gas heated dwellings	2031 UPC decrease of 1.1% relative to reference case
			Carbon: $3/GJ	2% of existing gas furnaces requiring replacement switch to non-gas fuel	
			Total: $15.034/GJ	2% of existing DHW units requiring replacement switch to non-gas fuel	
	C	Low gas price, low carbon price	Gas: $6.14/GJ	9% increase in growth of gas heated dwellings	2031 UPC increase of 1.2% relative to reference case
			Carbon: $1.50/GJ	9% of ducted non-gas heating systems requiring replacement switch to gas	
			Total: $7.64/GJ	9% of eligible non-gas DHW units requiring replacement switch to gas	
	D	Moderate gas price, moderate carbon price	Gas: $10.04/GJ	2% increase in growth of gas heated dwellings	2031 UPC increase of 0.3% relative to reference case
			Carbon: $2.25/GJ	2% of ducted non-gas heating systems requiring replacement switch to gas	
			Total: $12.29/GJ	2% of eligible non-gas DHW units requiring replacement switch to gas	
Economic Growth	Reference			No change from 2010 CPR assumptions other than updated base year	2031 UPC decrease of 19% relative to 2011
	A	Strong economic growth		No change to housing starts relative to reference case	No additional change. Cumulative 0.6% decrease in 2031 UPC relative to reference case.
	B	Moderate to strong economic growth		No change to housing starts relative to reference case	No additional change. Cumulative 1.1% decrease in 2031 UPC relative to reference case.
	C	Moderate economic growth		No change to housing starts relative to reference case	No additional change. Cumulative 1.2% increase in 2031 UPC relative to reference case.
	D	Slow economic growth		No change to housing starts relative to reference case	No additional change. Cumulative 0.3% increase in 2031 UPC relative to reference case.
	Reference			No change from 2010 CPR assumptions other than updated base year; furnaces rise to 90% efficiency, envelope renovations occur at natural rate, adoption of EGH 80 occurs as planned, new DHW units improve to EF 0.64	2031 UPC decrease of 19% relative to 2011
				Funaces improve to average 94% efficiency	2031 UPC further reduced 3.4%, to

Residential					
Variable	**Scenario**	**Assumption**	**Value**	**Action Taken**	**Cumulative Result**
Government Policy	A	Focused on carbon reduction		Overall effect of envelope renovations increases by factor of 1.5 relative to reference case	cumulative 4.0% decrease relative to reference case
				Adoption of EGH 80 for new construction begins in 2013	
				40% of new DHW units are EF 0.8, compared to 20% in original reference case	
	B	Focused on environmental impacts of energy, not carbon reduction		Funaces improve to average 92% efficiency	2031 UPC further reduced 1.8%, to cumulative 2.9% decrease relative to reference case
				Overall effect of envelope renovations increases by factor of 1.25 relative to reference case	
				Adoption of EGH 80 for new construction begins in 2020	
				20% of new DHW units are EF 0.8: same as reference case	
	C	Focused on economic growth		Funaces remain at 90% efficiency	2031 UPC does not change from reference case; cumulative 1.2% increase relative to reference case
				Overall effect of envelope renovations same as reference case	
				Adoption of EGH 80 for new construction delayed until 2025	
				New DHW units retain same efficiency as in reference case	
	D	Focused on some economic growth, with some advancement of carbon regulations		Funaces improve to average 95% efficiency	2031 UPC further reduced 4.3%, to cumulative 4.0% decrease relative to reference case
				Overall effect of envelope renovations increases by factor of 1.6 relative to reference case	
				Adoption of EGH 80 for new construction begins in 2013	
				50% of new DHW units are EF 0.8, compared to 20% in original reference case	
Renewable, Thermal, and Energy Efficiency	Reference			No change from 2010 CPR assumptions other than updated base year; negligible penetration of renewables and district energy	2031 UPC decrease of 19% relative to 2011
	A	Renewable thermal and energy efficiency a priority		Renewable penetration for space heating, DHW and pools rises to 1% of new and 0.5% of existing dwellings by 2021, and then stabilizes	2031 UPC further reduced 0.6%, to cumulative 4.6% decrease relative to reference case
				District energy penetration for space heating and DHW negligible to 2021 and then rises to 0.25% of dwellings by 2031	
	B	Strongest market penetration for renewable thermal		Renewable penetration for space heating, DHW and pools rises to 1.5% of new and 0.75% of existing dwellings by 2021, and then stabilizes	2031 UPC further reduced 0.9%, to cumulative 3.8% decrease relative to reference case
				District energy penetration for space heating and DHW negligible to 2021 and then rises to 0.37% of dwellings by 2031	
	C	Less market penetration for renewable thermal, compared to		Renewable penetration for space heating, DHW and pools rises to 0.15% of new and 0.05% of existing dwellings by 2021, and then stabilizes	2031 UPC reduced 0.2%, to cumulative 1.0% increase relative to reference case

Residential					
Variable	**Scenario**	**Assumption**	**Value**	**Action Taken**	**Cumulative Result**
	C	renewable thermal, compared to other scenarios		District energy penetration for space heating and DHW negligible to 2021 and then rises to 0.10% of dwellings by 2031	
	D	Slower market penetration for renewable thermal, compared to other scenarios		Renewable penetration for space heating, DHW and pools rises to 0.25% of new and 0.10% of existing dwellings by 2021, and then stabilizes	2031 UPC further reduced 0.3%, to cumulative 4.3% decrease relative to reference case
				District energy penetration for space heating and DHW negligible to 2021 and then rises to 0.20% of dwellings by 2031	
Regional Energy Strategies	Reference			No change from 2010 CPR assumptions other than updated base year	2031 UPC decrease of 19% relative to 2011
	A	Energy strategies consistent within regions, but may be disparate between regions		Provides context; no change from reference case	No further change in UPC
	B	Coordinated energy strategies among regions and all levels of government		Provides context; no change from reference case	No further change in UPC
	C	Disparate energy strategies among regions and all levels of government		Provides context; no change from reference case	No further change in UPC
	D	Disparate energy strategies among regions and all levels of government		Provides context; no change from reference case	No further change in UPC

Attachment 24.1.1

City	Annual Bill		
	Natural Gas	Electricity	Percentage
Vancouver, BC			
Utility	*FEI*	*BC Hydro*	
Annual Bill Calculations			
Daily Basic Charge	$ 0.3890		
Delivery per GJ	$ 3.547		
Storage and Transport per GJ	$ 1.334		
Cost of Gas per GJ	$ 2.486		
BC Carbon Tax per GJ	$ 1.4898		
Average price per kW.h [1]		$ 0.1029	
Average price per GJ		$ 28.58	
Avg price per GJ efficency adjusted [2]		$ 25.73	
Average Annual Bill (90 GJ)	**$ 939**	**$ 2,315**	**59%**

City	Annual Bill		
	Natural Gas	Electricity	Percentage
Calgary, AB			
Utility	*Atco Gas-Direct Energy*	*ENMAX*	
Annual Bill Calculations			
Fixed Daily Charge (Direct)	$ 0.223		
Fixed Daily Charge (Atco)	$ 0.812		
Delivery Charge per GJ (Atco)	$ 0.775		
Transmission Service Charge per GJ (Atco)	$ 0.738		
Gas Cost Recovery Charge per GJ (Direct)	$ 3.741		
Average price per kW.h [1]		$ 0.1166	
Average price per GJ		$ 32.39	
Avg price per GJ efficency adjusted [2]		$ 29.15	
Average Annual Bill (90 GJ)	**$ 851**	**$ 2,624**	**68%**

City	Annual Bill		
	Natural Gas	Electricity	Percentage
Toronto, ON			
Utility	*Enbridge Gas*	*Toronto Hydro*	
Annual Bill Calculations			
Basic Charge per Month	$ 20.00		
Delivery Charges per GJ			
First 1.2 GJ	$ 2.167		
Next 2.1 GJ	$ 2.046		
next 3.3 GJ	$ 1.951		
System Sales Gas Supply Charge per GJ	$ 3.791		
Gas Transportation Rate per GJ	$ 1.603		
Rider C per GJ	$ 1.164		
Rider E per GJ	$ (0.283)		
Average price per kW.h [1]		$ 0.1431	
Average price per GJ		$ 39.75	
Avg price per GJ efficency adjusted [2]		$ 35.78	
Average Annual Bill (90 GJ)	**$ 974**	**$ 3,220**	**70%**

City	Annual Bill		
	Natural Gas	Electricity	Percentage
Montreal, PQ			
Utility	*Gaz Metro*	*Hydro Quebec*	
Annual Bill Calculations			
Basic Fee per Day	$ 0.5345		
Natural Gas Supplied per GJ	$ 3.476		
Compressor Fuel per GJ	$ 0.183		
Transportation per GJ	$ 1.911		
Load-balancing per GJ	$ 1.188		
Inventory-related Adj. per GJ	$ 0.026		
Cap and Trade Allowance per GJ	$ 0.738		
Distribution Tariff D1	$ 6.149		
Average price per kW.h [1]		$ 0.0719	
Average price per GJ		$ 19.97	
Avg price per GJ efficency adjusted [2]		$ 17.98	
Average Annual Bill (90 GJ)	**$ 1,426**	**$ 1,618**	**12%**

[1] As per Page 20 of the Hydro-Québec Comparison of Electricity Prices in Major North American Cities for rates in effect April 1, 2015.

[2] The efficiency of gas equipment is assumed to be 90% relative to 100% for electricity to determine equivalent electricity.

[3] Converted from price per m^3 to gigajoules at a conversion rate of 1 gigajoule = 25.7 m^3.

Attachment 25.1

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 32.2

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 33.2

REFER TO LIVE SPREADSHEET MODELS

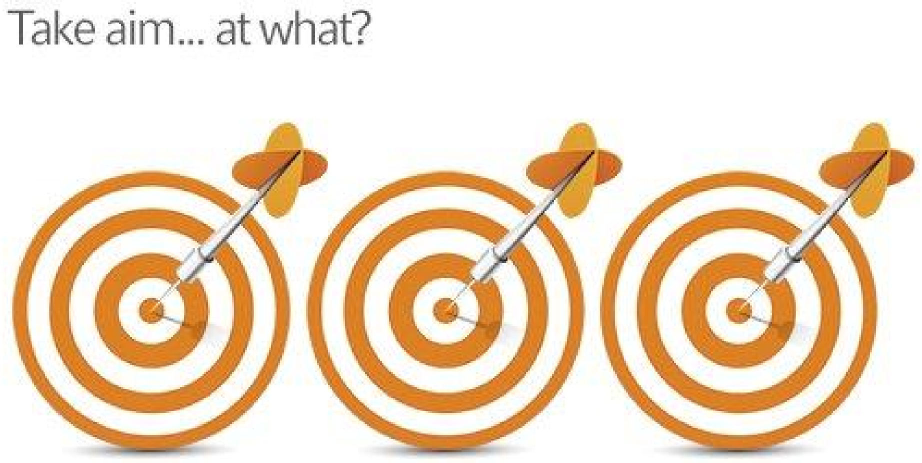
Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 40.2

What is a pension plan's return objective? Well, it's not ELTRA…

JUNE 4, 2014 | By Bob Collie



At Russell, we see our role as being to help our clients earn the rate of return they require at a level of risk they can survive. That's a neat formulation: but when it comes to defined benefit pension plans, we need to stop and ask ourselves what precisely *is* the rate of return that they require. (See last week's blog for a discussion of the return objective for non-profit organizations.)

Making things harder is the fact that one obvious candidate—the plan sponsor's Expected Long Term Rate of Return on Assets (ELTRA)—is, for reasons I will get to in a moment, usually not a good proxy for the true required return at all.

But, before we worry about what the required return is not, let's think about what it is. The impact of pension plan returns is felt in contribution requirements and in the surplus/shortfall position of the plan. Investment returns plus plan sponsor contributions together need to (a) match the growth in existing liabilities, plus (b) cover the value of new benefit accruals, plus (c) get rid of any shortfall in the plan's funding over some reasonable time horizon. So if it were not for the "at a level of risk they can survive" clause in our description above, then the ideal return target (sometimes called the hurdle rate) would cover all of these without any additional contributions at all being required.

But unless the plan is frozen and well-funded, that hurdle rate may well not be feasible. You cannot necessarily ask the investments alone to do all of the work; some contributions may be necessary too. So, in practice, the actual target return from the investments is derived in conjunction with a funding (contribution) policy. And it is generally implicit. That is to say, a decision on asset allocation policy is made based on expected contributions (or surplus) rather than directly based on expected return. But the return target is there nonetheless—typically somewhere around 5-8% in our experience.

So what about ELTRA? The typical U.S. corporation currently sets its ELTRA in the range of 7–8%. That's just the U.S. approach, though: International Accounting Standards in effect set ELTRA equal to the liability discount rate. As my colleague Jim Gannon has pointed out to me, if a corporation decided to switch from Financial Accounting Standards (FAS) to International Accounting Standards (IAS) (resulting in a reduction in ELTRA), that would not be a reason to reduce the pension plan's return target from 7.5% to 4.8%.

And, since we have just described the return target in terms of contributions and the plan sponsor's balance sheet, ELTRA, which forms part of neither calculation, is irrelevant anyway. But what if we wanted to define risk in terms of pension expense and the earnings statement (which do use ELTRA)? In that case, we run into a different problem: the current approach to pension expense, which dates from 1985, is a truly bizarre calculation. One of its oddities is that if you earn less than the ELTRA, the impact of doing so does not show up in the earnings statement for quite a long time (if at all) thanks to a series of corridors and other smoothing mechanisms. The upshot of the bizarre calculation is that it's almost impossible to meaningfully measure the risk of different investment strategies in terms of their impact on earnings.

I am not denying that, for some corporations (such as utilities whose rate case includes pension expense) ELTRA can matter. But, even in those cases, ELTRA matters as an end in itself, not as a return target; so even when ELTRA is important to a corporation, performance relative to ELTRA is still not a useful measure of success.

So, convenient as the idea of using the earnings statement's expected return as the plan's return target might appear, it's not the right answer.

One afterthought: I have noted in the past (most recently in 2011) that a new U.S. standard for the treatment of pension expense should be expected at some point. Let's just say that whatever momentum this initiative once had, it seems to have lost. I'm sticking to my "change is a-coming" stance, but it's sure taking its time.

USI-19655-12-17

TEACHERS' PENSION PLAN
ONTARIO
25 YEARS

2014 ANNUAL REPORT

25 YEARS OF BUILDING FOR THE FUTURE

ABOUT ONTARIO TEACHERS' PENSION PLAN

The Ontario Teachers' Pension Plan, better known as Teachers', is Canada's largest single-profession pension plan. Teachers' is an independent organization set up by its two sponsors, the Ontario government and Ontario Teachers' Federation (OTF). OTF represents all members. The Ministry of Education and the Ministry of Finance jointly represent the Ontario government.

Ontario > TEACHERS' PENSION PLAN < OTF

WHAT DO THE SPONSORS DO?

- Appoint independent board members
- Set benefits and contribution rates
- Ensure the plan is appropriately funded with enough money to meet its obligation to members

WHAT DOES TEACHERS' DO?

- Earns money – through investing – to help pay pensions
- Administers the plan and pays benefits
- Reports and advises on the plan's funding status and regulatory requirements

TABLE OF CONTENTS

Since 1990, Teachers' has been recognized as an innovator and leader that introduced a new pension model to the world. We're proud of that achievement, but we're more interested in what's ahead, in expanding our global presence, in establishing rewarding partnerships, in delivering growth. And in building for the future.

2014 HIGHLIGHTS

Strong investment returns, combined with recent contribution and benefit changes, produced the plan's second consecutive preliminary funding surplus at January 1, 2015.

FUNDING

Preliminary surplus represents **104% funding** based on current benefit and contribution levels

$6.8 billion

INVESTMENTS

Rate of return for 2014 was above benchmark and exceeded our annualized return of 10.2% since inception, boosting net assets to **$154.5 billion**

11.8%

SERVICE

Service satisfaction rating from plan members (**182,000 active** and **129,000 pensioners**) remains at an industry-leading level

9.2/10

REPORT FROM THE CHAIR

Since taking over as board chair in January, and in my previous terms as a board member, I have been immersed in the strategic and investment issues facing the Teachers' organization.

When the inaugural board began work 25 years ago, creating an institution that is now respected around the world, I dare say the issues were much different than they are now. Twenty-five years on, the pension fund is substantially larger and more diverse; employees and plan assets are global, necessitating more investment in talent and risk management; technology is dramatically different; and the plan serves more members, who are living longer. These changes and complexities shape our plan governance discussions and strategic decisions.

In 2014, after a decade of regular funding shortfalls, Teachers' reported a preliminary surplus of $5.1 billion. The plan sponsors, Ontario Teachers' Federation and the Ontario government, used this surplus to partially restore inflation protection to recent retirees. The funding valuation they filed with the regulatory authorities included a modest surplus of $1.2 billion.

As of January 1, 2015, the plan had another preliminary surplus; this time it is $6.8 billion. The credit for this positive development goes to the sponsors, for making recent contribution and benefit changes, and to plan management, for consistently posting solid investment returns. It will be up to the sponsors to determine what to do with any surplus if they decide to file the January 1, 2015, valuation.

The sponsors worked together in 2014 to address important issues. Their joint task force refined the funding management policy, which sets out how the sponsors handle funding surpluses or shortfalls, and they analyzed demographic issues, including the imbalance between the number of years, on average, that members contribute to the plan (26) and the number of years they collect a pension (31).

Teachers' governance model – including an independent, professional board – is justly hailed as a key component of its success. My predecessor as board chair, Eileen Mercier, served with great dedication for 10 years. On behalf of my colleagues, I thank Eileen for her strong leadership.

We also said farewell to board members Hugh Mackenzie and Patsy Anderson, and welcomed new board members John Murray, former Deputy Governor of the Bank of Canada; Bill Chinery, an actuary and former CEO of Blackrock Asset Management Canada; and Steve McGirr, a former chief risk officer at CIBC. Our thanks go to all of these talented individuals for contributing their time and expertise on behalf of Ontario's teachers.

Jean Turmel

Jean Turmel, B.Comm., MA
Chair

REPORT FROM THE CEO

Our focus on agility, innovation and partnerships paid off with solid investment results and strong service scores in 2014.

Teachers' performance reflects our culture, and is driven by our mission: Outstanding service and retirement security for our members – today and tomorrow. In fact, we revisited our Mission, Vision and Values in 2014, and employees told us resoundingly that our mission should not change – that we should continue to ensure the best possible service and risk-adjusted returns on our members' behalf.

The fund's net assets grew to $154.5 billion last year, with a rate of return of 11.8%. These strong results were achieved despite a turbulent investment environment: low interest rates, intense global competition pushing up asset prices, the fourth-quarter slide in oil prices and resulting stock market volatility. It was not an easy road to success.

Our Member Services employees continue to simplify our members' experience and make it more personal. For the third straight year, CEM Benchmarking Inc., an independent industry benchmarking firm, ranked our service to members number one.

In 2015, Teachers' marks its 25th anniversary as an independent organization and the birth of our mandate to build a diversified investment portfolio. Canadian pension funds in 1990 were not the major investment force that they are today, and I salute Teachers' founders for establishing the culture of high performance that prevails today.

As we continued to implement major technology and process changes that will improve our agility in today's increasingly complex business and investment environments, it became apparent that a full-time, dedicated operations executive was needed. After a detailed review of our structure, we created the new position of Chief Operations Officer in late 2014. We were delighted that Rosemarie McClean, previously our Senior Vice-President, Member Services, took on this new role.

We drew from our depth of in-house experience in filling two executive team vacancies in 2014. Tracy Abel was appointed Senior Vice-President, Member Services, and Jeff Davis was appointed General Counsel, Senior Vice-President, Corporate Affairs and Corporate Secretary. Congratulations to them.

A few things about 2015 are already clear. First, the sponsors' decision to adopt conditional inflation protection will continue to prove prudent. It is the biggest impact move the sponsors could have taken from a funding perspective, as it helps us manage our liability risk related to interest-rate sensitivity. This new provision's impact will continue to grow into the plan in coming years. We also face asset risks, however, especially the risk of another 2008-like asset shock. Should such an event occur, additional, but smaller, changes could be needed to buttress the fund. Our liability risks are further compounded by members' ever-increasing longevity rates. We are glad the sponsors continue to discuss what additional options might be appropriate.

Second, markets are unpredictable and, as a mature pension plan, we will continue to closely manage assets to reduce the risk of financial loss. Third, with heated competition for good investment opportunities, we will keep looking for the best global prospects with our partners; our international expansion is designed to help us do that.

I would like to thank the board members and Teachers' employees for their support during my first year as CEO.

R Mock.

Ron Mock, B.A.Sc., MBA
President and Chief Executive Officer

MANAGEMENT'S DISCUSSION & ANALYSIS

Management's Discussion and Analysis (MD&A) presents a view of the pension plan through the eyes of management by interpreting the material trends and uncertainties affecting the results and financial condition of the plan. The MD&A includes historical information and forward-looking statements about management's objectives, outlook and expectations. Such statements involve risks, assumptions and uncertainties, and the plan's actual results will likely differ from those anticipated. The plan's consolidated financial statements should be read in conjunction with the MD&A.

MISSION

Outstanding service and retirement security for our members – today and tomorrow

VISION

Striving to be the world's leading pension plan

VALUES

INTEGRITY: We do the right thing
INNOVATION: We have the courage to forge new paths
PERFORMANCE: We are driven to succeed
PARTNERSHIP: We are stronger together
HUMILITY: We temper our accomplishments

FOR MORE INFORMATION, VISIT OTPP.COM/MISSIONVISIONVALUES

EXECUTIVE TEAM

(l-r) **Ron Mock**, B.A.Sc., MBA, President and Chief Executive Officer; **Neil Petroff**, BBA, MBA, Executive Vice-President, Investments, and Chief Investment Officer; **Tracy Abel**, BA, MBA, Senior Vice-President, Member Services; **David McGraw**, B.Comm., MBA, FCPA, FCA, ICD.D, Senior Vice-President and Chief Financial Officer; **Rosemarie McClean**, BA, MBA, CPA, CMA, ICD.D, Senior Vice-President and Chief Operations Officer; **Barbara Zvan**, M.Math, FSA, FCIA, CERA, Senior Vice-President, Asset Mix & Risk, and Chief Investment Risk Officer; **Jeff Davis**, BA, LLB, General Counsel, Senior Vice-President, Corporate Affairs, and Corporate Secretary; **Marcia Mendes-d'Abreu**, BA, M.Sc., HRCCC, Senior Vice-President, Human Resources & Facilities

PLAN OVERVIEW

The Ontario Teachers' Pension Plan (Teachers') manages investments and administers pension benefits on behalf of its members: Ontario's 182,000 school teachers and 129,000 pensioners.

Teachers' has approximately 1,100 employees in Toronto, London and Hong Kong.

The pension plan is governed by the *Teachers' Pension Act* and must comply with Ontario's *Pension Benefits Act*, the federal *Income Tax Act*, and laws in the various jurisdictions in which it invests.

Ontario Teachers' Federation (OTF) and the Ontario government are the plan's joint sponsors. Together, OTF and the government ensure the plan remains appropriately funded to pay pension benefits. The sponsors jointly decide the contribution rate paid by working teachers (and matched by the government and designated employers); the benefits that members will receive, including inflation protection; and how to address any funding shortfall or apply any surplus.

Management's role

Management of the pension plan has three main responsibilities:

- invest plan assets to help pay pensions;
- administer the plan and pay pension benefits to members and their survivors;
- report and advise on the plan's funding status and regulatory requirements.

Management sets long-term investment and service strategies that take member demographics, economic, investment and market issues, and numerous other factors into account.

STATE OF THE PLAN

The Ontario Teachers' Pension Plan is designed to deliver pension benefits to its members for life.

Balancing plan assets and the cost of future benefits is an ongoing objective for the two sponsors of the plan: Ontario Teachers' Federation (OTF) and the Ontario government. The sponsors set contribution rates and pension benefits based on the plan's funded status.

At January 1, 2015, for the second consecutive year, the plan had a preliminary surplus. This surplus assumes current levels of contributions and benefits continue in the future. The sponsors will determine how to apply this surplus if they decide to file the funding report with the regulatory authorities.

For more information on plan funding, visit otpp.com/planfunding

FUNDING STATUS

2015 preliminary valuation

The plan's preliminary funding valuation showed a surplus of $6.8 billion at the start of the year. At January 1, 2015, the plan had 104% of the assets required to meet future pension liabilities, based on current contribution rates and current (reduced) levels of inflation protection.

Current inflation protection is set at 60% of the Consumer Price Index (CPI) increase for pension credit earned after 2009 and 100% for pension credit earned before 2010. Current contributions are based on 11.5% of earnings below the Canada Pension Plan (CPP) limit and 13.1% of earnings above the CPP limit. The 2014 CPP limit was $52,500.

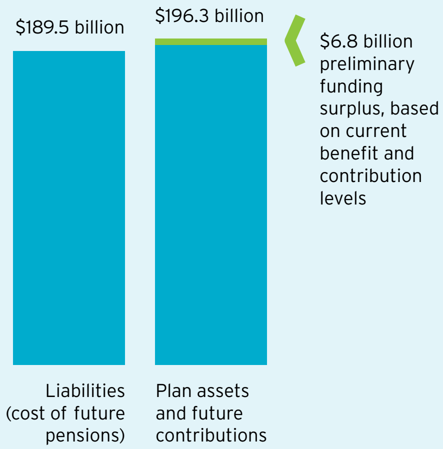
2014 filed valuation

In 2014, OTF and the Ontario government filed a funding valuation with the regulators. The sponsors used a $5.1 billion preliminary surplus to partially restore inflation protection for recent retirees. Pensioners who retired after 2009 received a one-time increase in January 2015 to bring their pension up to the level it would have been at if full inflation protection had been provided each year since they retired.

Inflation protection on the portion of pension credit that plan members earned after 2009 is conditional on the funded status of the plan. This lever, known as conditional inflation protection (CIP), is used to help keep the plan sustainable in the long term. Inflation increases may be bigger if there is a projected funding surplus, or smaller if there is a projected funding shortfall. Pension credit earned before 2010 remains fully indexed to inflation.

PRELIMINARY FUNDING VALUATION

As at January 1, 2015



PENSION FUNDING SOURCES SINCE 1990

- **10%** Member Contributions
- **12%** Government/Employer Contributions*
- **36%** Investments – Active Management
- **42%** Investments – Benchmark

*Includes 1% original plan deficit funding.

1.4

Number of active teachers for each pensioner

0.62%

Yield for Canadian real-return bonds at end of 2014

FUNDING VALUATION SUMMARY

As at January 1 (Canadian $ billions)

	2015 Preliminary	2014 Filed	2014 Preliminary
Net assets available for benefits	$ 154.5	$ 140.8	$ 140.8
Smoothing adjustment	(8.2)	(7.2)	(7.2)
Value of assets	**$ 146.3**	**$ 133.6**	**$ 133.6**
Future basic contributions	38.8	37.5	37.5
Future special contributions	3.4	3.5	3.5
Future matching of CIP benefit reduction	7.8	7.4	9.0
Total assets	**$ 196.3**	**$ 182.0**	**$ 183.6**
Cost of future pensions	(197.3)	(188.2)	(188.2)
Reduction in cost due to less than 100% indexing	7.8	7.4	9.7
Surplus	**$ 6.8**	**$ 1.2**	**$ 5.1**
Assumptions (percent)			
Inflation rate	2.00	2.10	2.10
Real discount rate	2.85	2.85	2.85
Discount rate	4.85	4.95	4.95

Funding valuation background

A funding valuation is an assessment of the financial health of a pension plan at a defined date. Teachers' funding valuation:

- looks ahead more than 70 years;
- is prepared by an independent actuary;
- projects members' future contributions, benefits and their cost;
- is filed with government authorities at least every three years;
- must be balanced when filed.

The valuation uses a number of assumptions to project the value of future pension plan liabilities. Assumptions are made about future inflation, salary increases, retirement ages, life expectancy and other variables. One of the most important assumptions for the board to consider is the discount rate. Plan liabilities are sensitive to changes in the discount rate, with a decreased rate resulting in increased liabilities. The assumption setting process is extremely robust and includes an annual in-depth analysis of plan experience as well as input from the sponsors. The independent actuary must confirm that the assumptions are appropriate and works closely with board members in the assumption setting exercise. The Canadian Institute of Actuaries (CIA) Standards of Practice require that each assumption is independently reasonable and that assumptions are appropriate in aggregate.

The inflation rate and discount rate assumptions in the most recent valuations are shown in the Funding Valuation Summary table on page 7.

PLAN FUNDING CONSIDERATIONS

When making decisions on behalf of all beneficiaries, the plan's management and the sponsors consider ever-changing demographic and economic factors and risks.

The table below summarizes how the pension plan has evolved over the past quarter-century. It is followed by brief discussions of some key funding considerations. The plan has identified four main funding risks – longevity, interest rates, inflation and asset volatility – and also seeks to manage intergenerational equity.

6

Increase in expected years on pension since 1990

FUNDING VARIABLES 25-YEAR COMPARISON

	1990	**2014**
Average retirement age	58	**59**
Average starting pension	$29,000	**$44,000**
Average contributory years at retirement	29	**26**
Expected years on pension	25	**31**
Ratio of active teachers to pensioners	4 to 1	**1.4 to 1**
Average contribution rate	8.0%	**12.3%**
Increase in contributions required for 10% loss in assets	1.9%	**4.6%**

Longevity

Teachers in Ontario live longer than the general Canadian population and their life expectancy continues to increase. It costs more to pay lifetime pensions when members live longer. Members are contributing to the plan for fewer years than in the 1990s, and their retirement periods are longer. The plan is moving toward more innovative modelling to predict improvements in longevity, consistent with ongoing efforts by the actuarial profession in Canada, the United States and the United Kingdom.

Interest rates

Interest rates have declined globally since the onset of the 2008 financial crisis. Central banks have kept policy rates low and used other monetary tools to support economic growth. When interest rates are low, pension liabilities rise as more money must be set aside to earn enough to pay future pensions. In Canada, long-term real-return bond yields have declined from 1.25% over the last 10 years, on average, to 0.62% at the end of 2014. Interest rates also affect asset prices, so while an increase in rates could reduce the plan's liabilities, it could also reduce the value of our assets.

Inflation

The plan seeks to provide retired members with annual pension increases to offset the impact of inflation. Higher inflation increases the plan's liabilities. The level of annual increases is conditional on the plan's funded status. Inflation in Canada has been stable since 1991, generally remaining within one percentage point of the Bank of Canada's 2% target. In this era of low policy rates, economic uncertainty and volatile commodity and currency markets, it is more likely that inflation could miss the bank's target.

Asset volatility

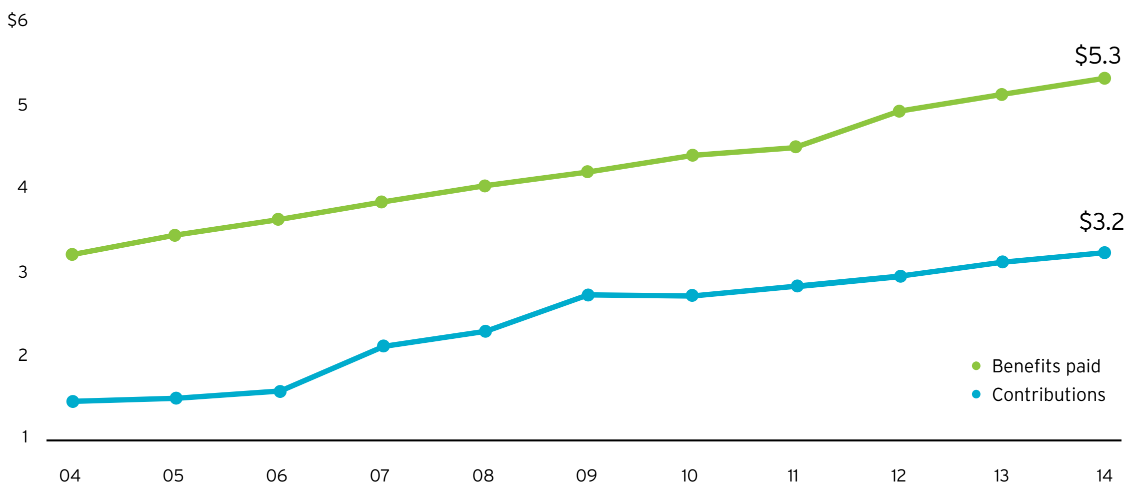
Good stock market performance in recent years has helped produce strong returns for the plan, but many valuations are now above historical norms. In an environment of modest global growth, heightened macroeconomic and geopolitical risks and an expected tightening of U.S. monetary policy, higher valuations will result in higher market volatility. Market downturns are expected to become more frequent and tighter regulation of financial market participants is likely to exacerbate the magnitude of such corrections. While declining asset prices can present opportunities for long-term investors such as Teachers', they can also lead to investment losses. As a result, Teachers' board members and management work constantly to understand various investment risks and how best to manage them.

Managing intergenerational equity

The plan's sustainability is defined as its ability to meet the needs of the present without compromising the ability of future generations to meet their own needs. Intergenerational equity must be considered because pensioners and teachers near retirement have already earned all or most of their pensions. Under Ontario's *Pension Benefits Act*, benefits already earned cannot be reduced to offset funding shortfalls. New and younger teachers, whose service lies mainly in the future, are therefore exposed to more funding risk, because their contribution rates *and* benefits can be adjusted to make up for shortfalls. If funding shortfalls are projected, the sponsors can increase contributions, adjust inflation protection, reduce future benefits, or employ a combination of these three measures. Conditional inflation protection, under which inflation protection can be adjusted depending on the plan's funded status, provides an effective means for mitigating our funding risks and will promote intergenerational equity over time.

CONTRIBUTIONS VS. BENEFITS PAID

For the years ended December 31 (Canadian $ billions)



$2.1 billion

Amount benefit payments exceeded contributions from members, government and designated employers in 2014

INVESTMENTS

Teachers' investment program is designed to help the plan meet its long-term funding needs. The plan continues to actively develop its strategies by expanding its global investment horizons to address ever-changing market and economic circumstances. Since its inception 25 years ago, more than three-quarters of the plan's income has come from investment returns, with the remainder from member and government contributions.

In 2014, the plan again realized the advantages accruing from its responsive, risk-managed approach. An 11.8% rate of return generated $16.3 billion of investment income from the plan's diversified portfolio, and increased its net assets to a record $154.5 billion, outperforming its composite benchmark to earn $2.4 billion in value added.

INVESTMENT OVERVIEW

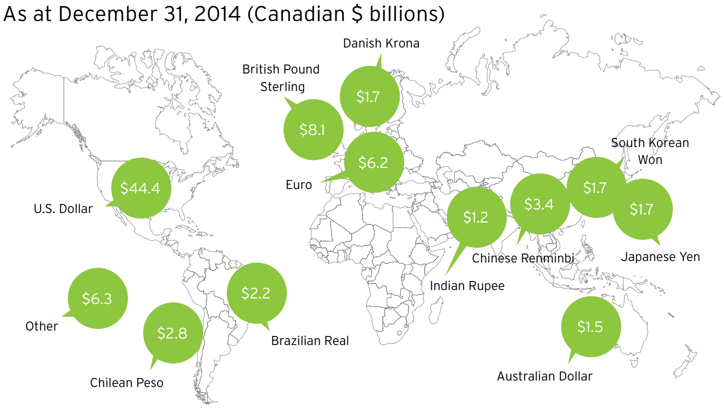
Teachers' is a globally active investor with holdings in more than 50 countries across diversified asset classes. Investment professionals are located at offices in Toronto, London and Hong Kong, sourcing and managing investments in the Americas, Europe–Middle East–Africa and Asia-Pacific, respectively. The growth of the plan's investment activities around the world is directly supported by its international presence and is a result of long-term strategies.

To achieve its objectives, the plan seeks to maximize investment returns at a level of risk that takes into account the cost and nature of future benefits (pension liabilities). The aim is to create a total portfolio with risk and return characteristics that support stable benefits and contribution rates, and plan sustainability.

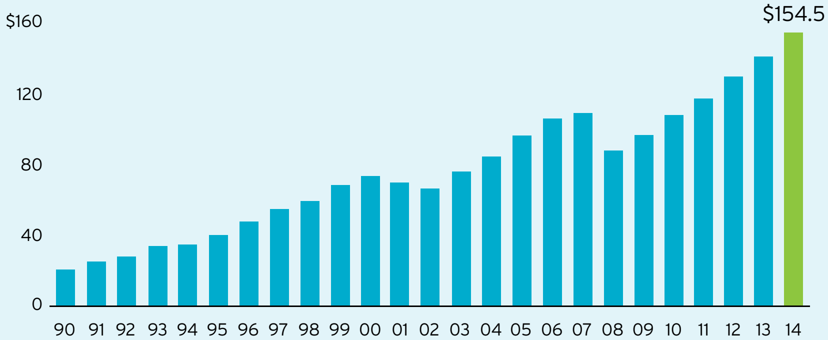
As a recognized innovator, the plan has developed and employs a number of integrated strategies. These strategies are driven by a set of Investment Beliefs that define the plan's philosophy for earning superior risk-adjusted returns and are consistent with Teachers' investment mandate in its Statement of Investment Policies and Procedures.

NET CURRENCY EXPOSURES

As at December 31, 2014 (Canadian $ billions)



NET ASSETS
As at December 31 (Canadian $ billions)



Net assets include investment assets less investment liabilities (net investments), plus the receivable from the Province of Ontario, and other assets less other liabilities.

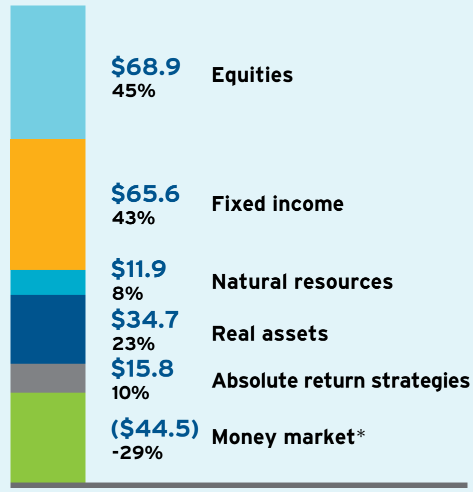
$16.3 billion

Investment income in 2014

10.2%

Annualized total return since 1990

NET INVESTMENTS BY ASSET CLASS
(Canadian $ billions)



TOTAL $152.4

*Money market asset class provides funding for investments in other asset classes.

Proactive risk management

Each year, the plan determines the level of total risk that is appropriate to meet its objectives, now and over the long term. Risk budgeting is then used to spread active risk across asset classes. Teachers' has continually advanced its risk culture with sophisticated tools and processes to support risk measurement and management on a coordinated basis across the entire fund, all asset classes, departments as well as within each portfolio.

Responsible investing: Teachers' approach to responsible investing supports the plan's sustainability by evaluating environmental, social and governance (ESG) risk factors alongside other risks and opportunities that are present in all phases of investment ownership. These factors can materially affect investment value and Teachers' reputation. Over time, ESG factors will become more efficiently priced into global investments and the plan will continue to refine its ESG assessment methods as responsible investing strategies evolve. Teachers' is an active member of organizations that promote improved disclosure of ESG factors and adoption of responsible investment practices, including the United Nations–backed Principles for Responsible Investment.

Corporate governance: Consistent with its responsible investing approach, Teachers' votes all of the shares of the companies it owns. In 2014, the plan voted at 1,983 shareholder meetings, with significant growth in voting activity in the United Kingdom, China and Hong Kong. It also continues to promote effective governance practices through engagement with governance groups worldwide, publication of its widely followed principles and guidelines, and advising on voting intentions through otpp.com.

PROXY VOTING
For the years ended December 31

Asset-mix selection

Recognizing that asset-mix selection is an important driver of performance, the plan devotes considerable attention each year to choosing the types of assets owned and the relative emphasis placed on each asset group and geography. The plan's asset-mix policy is approved by Teachers' board members annually and modified as necessary through the year.

Liquidity management

The plan must have sufficient cash to meet current liabilities and to opportunistically acquire investments and therefore manages its liquidity position carefully within the context of its investment policy. As part of its liquidity strategies, the plan tests its position periodically through simulations of major market events and reports its findings to the board's Investment Committee.

Active management

To add value, the plan employs active management strategies to identify undervalued investments and optimize returns. Passive investing through market indices cannot, alone, generate the risk-adjusted returns Teachers' needs to meet its objectives. Relationships with our investment partners around the world are key to the plan's successful active management program.

In-house talent

Teachers' provides employees across the organization with the resources, training and career opportunities needed to meet the highest professional standards. As one of Canada's largest pension funds, and with approximately 80% of the investment portfolio managed in-house today, Teachers' believes that developing industry-leading in-house expertise is especially important for the Investment Division. Having the intellectual capital and expertise required to employ sophisticated strategies and to innovate in areas such as risk management, private investments and emerging markets are key to our success.

2014 PERFORMANCE

The total-fund rate of return, net of trading costs, investment management expenses and external management fees is reported in Canadian dollars for four periods: one, four and 10 years, and since the current investment program began in 1990.

The plan also compares its performance to a Canadian dollar–denominated composite benchmark, which is calculated by aggregating results from each of the asset-class benchmarks and weighting those benchmarks so that they are the same as the plan's asset-mix policy weightings.

INVESTMENT PERFORMANCE

(percent)	**2014**	2013	4-Year	10-Year	Since Inception
Total return	**11.8**	10.9	11.7	8.6	10.2
Benchmark	**10.1**	9.3	10.0	7.2	8.0
Return above benchmark (Canadian $ billions)	**$2.4**	$2.1	$8.2	$15.6	$31.4

A complete list of benchmarks is available at otpp.com/benchmarks

Benchmarks

Benchmarking is important because it allows investment strategies and activities to be measured for effectiveness relative to the risks taken. Appropriate benchmarks are established by a committee, chaired by the CEO, and any changes to total plan benchmarks must be approved by Teachers' board members.

On a total-fund basis and for each investment class, the plan seeks to outperform benchmark rates of return, and when this happens, it is described as "value added."

Investment costs

The plan is committed to cost effectiveness. In 2014, total investment costs, including expenditures for salaries, benefits, fees and research, were $409 million or 28 cents per $100 of average net assets, compared to $364 million or 28 cents per $100 in 2013.

ASSET-CLASS REVIEW

(l-r) **Michael Wissell**, MBA, CFA, ICD.D, Senior Vice-President, Public Equities; **Jane Rowe**, MBA, ICD.D, Senior Vice-President, Teachers' Private Capital; **Wayne Kozun**, MBA, CFA, ICD.D, Senior Vice-President, Fixed Income & Alternative Investments; **John Sullivan**, MBA, President & CEO, Cadillac Fairview; **Andrew Claerhout**, HBA, ICD.D, Senior Vice-President, Infrastructure; **Ziad Hindo**, M.Sc., CFA, Senior Vice-President, Tactical Asset Allocation & Natural Resources

NET INVESTMENTS AND RATES OF RETURN BY ASSET CLASS

As at December 31	(Canadian $ billions)		(percent)			
			1-Year		4-Year	
	2014	2013	Actual	Benchmark	Actual	Benchmark
Equities			13.4	13.4	13.1	11.4
Canadian equity	**10.7**	10.9	12.7	12.2	6.0	5.7
Non-Canadian equity	**58.2**	51.0	13.5	13.6	14.9	12.7
Fixed income			12.0	11.9	6.8	6.5
Bonds	**35.2**	30.5	7.9	7.8	6.8	6.3
Real-rate products	**30.4**	26.4	17.1	17.1	6.8	6.8
Natural resources	**11.9**	10.8	(19.4)	(19.8)	(4.6)	(3.8)
Real assets			10.8	6.6	13.8	10.0
Real estate	**22.1**	19.2	11.1	7.3	15.4	14.0
Infrastructure	**12.6**	11.7	10.1	5.9	10.7	7.7
Absolute return strategies[1]	**15.8**	12.2				
Money market[1]	**(44.5)**	(33.8)				
Total plan[1]	**152.4**	138.9	11.8	10.1	11.7	10.0

[1] Returns generated by absolute return strategies and money market are included in the total plan return and not attributed to an asset class.

Net investments are defined as investments of $225.2 billion minus investment-related liabilities of $72.8 billion. See the consolidated statements of financial position (page 37).

$152.4 billion

2014 net investments

Equities

The plan uses equities to deliver long-term investment growth and income and applies various strategies to deliver value-added performance. This asset class includes public equities (those trading on a stock exchange) and private equities (not stock-exchange traded), managed by the public equities group and Teachers' Private Capital, respectively. Any funds not in an active program are managed passively by the plan to maintain exposure to the equity markets at the level outlined in our asset-mix policy. The asset class, which is reported as Canadian and non-Canadian equities, had 2014 total returns of 13.4%, equal to the benchmark.

Dividends added $1.2 billion to the plan's one-year performance as dividend yields in North America remained well above inflation and bond yields. On a constant policy weight, the total value of the plan's equities increased to $68.9 billion at the end of 2014 from $61.9 billion a year earlier.

Public equities: The public equities department approaches active investing by choosing equities using bottom-up fundamental analysis. It also uses a relationship investing strategy which involves taking significant minority ownership positions in public (and sometimes pre-IPO private) companies, partnering with world-class entrepreneurs while investing in companies with the potential for excess returns. In 2014, the world's major equity markets, expressed in Canadian dollars, were generally positive.

PUBLIC EQUITIES PORTFOLIO
As at December 31, 2014

- **25%** Consumer Discretionary
- **22%** Financials
- **11%** Information Technology
- **11%** Industrials
- **9%** Consumer Staples
- **7%** Healthcare
- **6%** Energy
- **5%** Materials
- **4%** Telecommunication and Utilities

Teachers' Private Capital: TPC invests directly in private companies, either on its own or with partners, and indirectly through private equity and venture capital funds. TPC seeks to add value in its portfolio companies by assisting in long-term business planning, ensuring good governance practices and developing board and management talent.

Private equity investments totalled $21.0 billion at year end, compared to $14.8 billion at December 31, 2013. Growth in the portfolio reflected an increase in the book value of existing investments (including the consolidation of the Long-Term Equities (LTE) portfolio at the start of 2014) and 13 new direct investments, partially offset by net realizations from fund investments and divestments. In 2014, TPC returned 22.0%, exceeding its 16.3% benchmark.

TPC PORTFOLIO
As at December 31, 2014

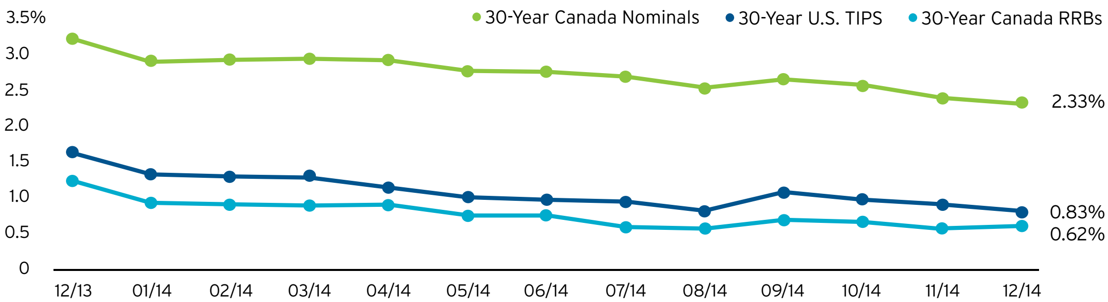
- **33%** Consumer and Retail
- **22%** Industrials
- **18%** Telecom, Media and Technology
- **10%** Healthcare
- **9%** Financial Services
- **4%** Energy and Power
- **4%** Venture Capital and Growth Equity

Fixed income

Teachers' uses fixed income investments to provide security and steady income, to hedge against interest-rate risks inherent in the plan's liabilities and to stabilize total returns. The plan owns a portfolio of government bonds, provincial bonds, corporate bonds and real-return bonds. Real-return bonds provide returns that are indexed to inflation, as measured by the Consumer Price Index, and include debt issued primarily by the Canadian and U.S. federal governments.

At 2014 year end, fixed income assets totalled $65.6 billion, compared to $56.9 billion at December 31, 2013. Returns for 2014 were 12.0% and the benchmark was 11.9%. Fixed income assets enjoyed strong returns in 2014 due to the decrease in longer-term interest rates.

GOVERNMENT BOND YIELDS



Real assets

Real assets include real estate and infrastructure investments. Strategically, these assets provide returns that are often related to changes in inflation and therefore hedge against the cost of paying inflation-protected pensions.

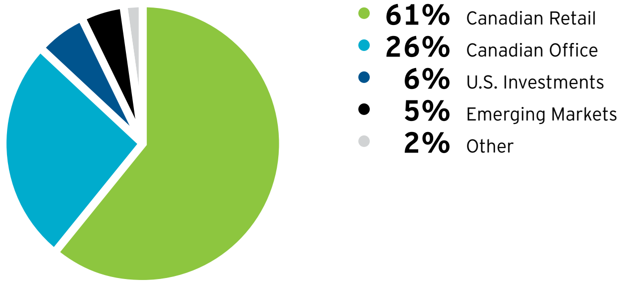
At December 31, 2014, the total value of real assets was $34.7 billion, compared to $30.9 billion at year-end 2013. Total returns for 2014 were 10.8%, exceeding the 6.6% benchmark.

Real estate: The real estate portfolio is managed by the plan's wholly owned subsidiary, The Cadillac Fairview Corporation Limited, which maintains a well-balanced portfolio of retail and office properties designed to provide dependable cash flows.

The real estate portfolio returned 11.1% compared to a benchmark return of 7.3% for the year ended December 31, 2014. Net asset value of real estate holdings was $22.1 billion at year-end 2014, compared to $19.2 billion the previous year. The increase reflected valuation growth in North American properties as demand for high-quality assets remained strong, driving further capitalization rate declines in the year. Portfolio highlights included: the acquisition of the Hudson's Bay downtown flagship retail complex and Simpson's Tower, including a commitment to open the first Saks Fifth Avenue stores in Canada at Toronto Eaton Centre and Sherway Gardens; the sale of the 49% interest in the U.S. retail portfolio to our partner Macerich in exchange for common shares; further investment in major development projects including new office towers in Calgary and Montreal, and expansions of Rideau Centre in Ottawa and Sherway Gardens in Toronto; and additional investment in emerging markets in Brazil and Colombia. The portfolio earned operating income of $1.0 billion in 2014, primarily from retail and office properties. At year end, the retail occupancy rate was 94% (95% in 2013), while the office occupancy rate was 96% (96% in 2013), in line with long-range targets.

REAL ESTATE PORTFOLIO

As at December 31, 2014 (based on total assets)

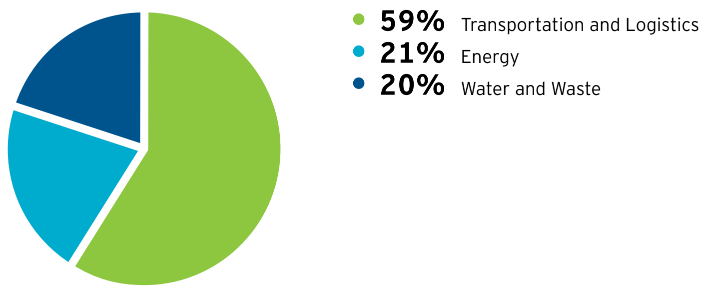


Infrastructure: The plan's infrastructure assets include investments in airports, seaports, high-speed rail, power generation and distribution, water and wastewater treatment. The majority of infrastructure assets are held outside of Canada, principally in the U.K., Europe, Chile, U.S. and Australia. Overall, Teachers' seeks to build an infrastructure portfolio which will steadily increase in value, provide predictable cash flow and correlate to inflation.

The value of the infrastructure portfolio increased to $12.6 billion at the end of 2014 from $11.7 billion the previous year. The growth is due to additional investments and higher valuations for existing assets, divestments and new investments. In 2014, infrastructure assets returned 10.1%, compared to a benchmark of 5.9%.

INFRASTRUCTURE PORTFOLIO

As at December 31, 2014

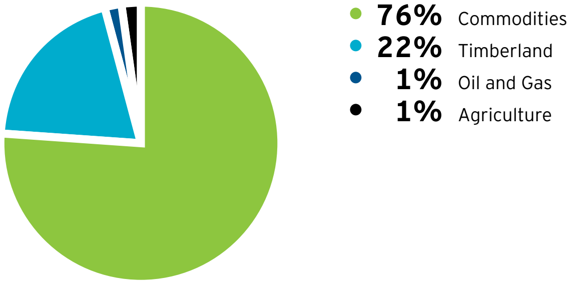


Natural resources

Natural Resources invests in commodity indices and directly in physical, producing natural resource assets. Current physical investments include timberlands, agriculture and Canadian oil and gas assets, with a mandate that also includes mining sector acquisitions. The asset group aims to provide the plan with superior risk-adjusted returns, diversification and protection against adverse macroeconomic environments that could lead to unexpectedly high inflation.

Investments in natural resources increased to $11.9 billion at year-end 2014 from $10.8 billion at December 31, 2013. The growth primarily reflects additional investments to sustain policy asset weighting. The portfolio returns for 2014 were -19.4%, largely due to lower commodity prices and slightly above the benchmark of -19.8%.

NATURAL RESOURCES PORTFOLIO
As at December 31, 2014



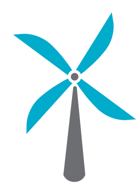
Absolute return and money market

Teachers' uses absolute return strategies to generate positive returns that are constructed to be uncorrelated to the returns of the plan's other assets. These strategies are executed primarily by the Tactical Asset Allocation and Fixed Income & Alternative Investments teams. Internally managed absolute return strategies generally look to capitalize on market inefficiencies. The plan also uses external hedge fund managers to earn uncorrelated returns, to access unique strategies that augment returns and to diversify risk. Assets employed in absolute return strategies totalled $15.8 billion at 2014 year end compared to $12.2 billion the previous year.

Money-market activity provides funding for investments in all asset classes, and is comparable to a corporation's treasury department. Derivative contracts and bond repurchase agreements have played a large part in the investment program since the early 1990s. For efficiency reasons, the plan often uses derivatives to gain passive exposure to global equity and commodity indices instead of buying the actual securities. The plan uses bond repurchase agreements to fund investments in all asset classes because it is cost effective and allows Teachers' to retain economic exposure to government bonds. These activities result in a negative net exposure in the asset mix, and the amount is expected to vary from year to year based on the plan's needs.

NOTABLE TRANSACTIONS

The plan publishes a list of individual investments that exceeded $150 million at year-end 2014, beginning on page 68. Some notable transactions announced in 2014 are described below:



Renewable Energy: Teachers' Infrastructure Group, together with the Public Sector Pension Investment Board and Banco Santander, agreed to jointly acquire a US$2 billion portfolio of wind, solar and water infrastructure assets that are operating or under development in seven countries. To manage these assets, when the deal closes in 2015 the partners will create a new company and plan to invest significantly in its growth over the next five years.

Irish National Lottery: Premier Lotteries Ireland Limited (PLI), a Teachers' subsidiary in partnership with An Post, finalized terms with the Irish government to operate the Irish National Lottery under a 20-year licence. Camelot Group, the operator of the U.K. National Lottery and owned by Teachers', will provide consulting services that build on its expertise in the international lottery sector. The transaction was led by Teachers' Private Capital's Long-Term Equities group.

GE Aviation: Teachers' entered into a partnership with GE Aviation to fund development of technologies for the fuel-efficient GE9X engine which will power Boeing's 777X aircraft. In connection with this partnership, Teachers' public equities team established a global relationship with the Development Bank of Japan to provide innovative financing.

MEMBER SERVICES

Outstanding service to members is central to Teachers' mission. The plan delivers personalized service through both digital communications and direct service channels to meet the needs of a broad range of member demographics.

Member Services administers one of Canada's largest payrolls, with pension and benefit payments of $5.3 billion in 2014.

For the third year in a row, Member Services was ranked number one for pension service in its peer group and internationally for 2013. This ranking is provided by CEM Benchmarking Inc., an independent company which measures the performance of global pension funds.

2014 HIGHLIGHTS

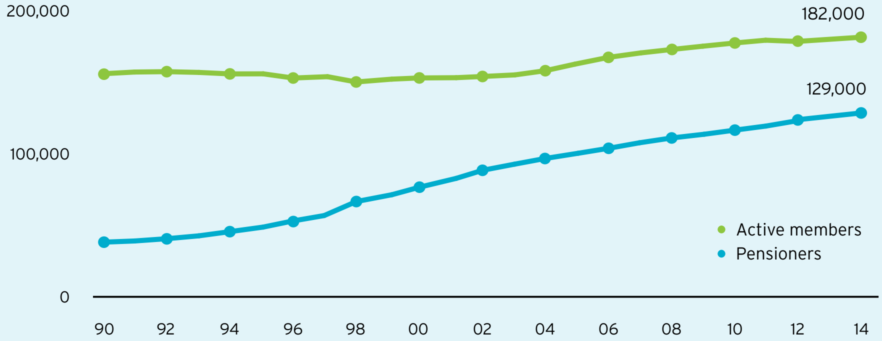
Teachers' service strategy focuses on three objectives: simplification, personalization and insight. In 2014, the Member Services Division continued to simplify pension information and streamline processes where possible; provided personalized service at different stages of teachers' lives; and used member data and trend indicators to make service improvements. Employees also worked closely with school boards and designated employers to ensure accuracy of employment data and reported information.

In 2014, Member Services reorganized its customer contact centre into five teams based on core member experiences in order to enhance the delivery of personalized service to members. Now, the Client Solutions team handles member phone calls and provides immediate service. If members need more intricate guidance – when retiring or leaving the plan, for example – they are directed to the appropriate team.

Teachers' continues to introduce innovative digital tools to help members understand plan rules and benefits. Its three mobile applications cater to various stages of a teacher's life. BabySteps – the latest arrival in the app family – is lifestyle focused and enables women on maternity leave to track the pension service they can buy back. It also features content from award-winning parenting experts. BabySteps complements two apps released in 2013 – Worklog and Classtime. Collectively, these apps have been downloaded more than 3,500 times, with over 100,000 user sessions.

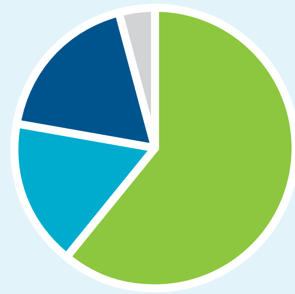
ACTIVE MEMBERS AND PENSIONERS

As at December 31



SERVICE SATISFACTION ACCORDING TO SURVEYS

For the year ended December 31, 2014



- **61%** 10/10 Extremely Satisfied
- **17%** 9/10 Very Satisfied
- **18%** 7-8/10 Satisfied
- **4%** 6 and Under - Neutral or Not Satisfied

4,550

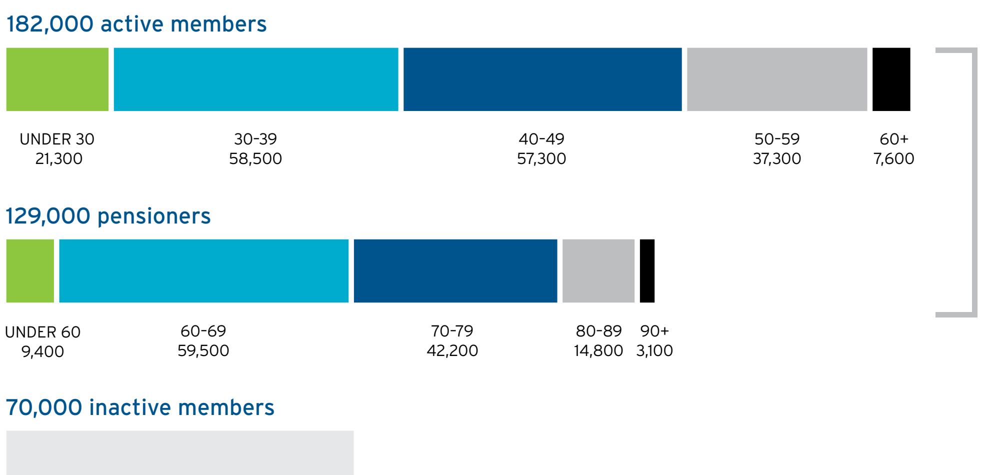
Number of new retirements in 2014

135

Number of pensioners aged 100 years or more at end of 2014

MEMBERSHIP FACTS

TEACHERS AND PENSIONERS BY AGE



311,000

Total number of active members and pensioners

26	Typical years of credit at retirement
31	Average years retirees are expected to collect pensions
59	Average age of teachers retiring last year
7,600	Number of teachers entering or returning to the teaching profession

SERVICE PERFORMANCE

Members consistently rate the plan's services very highly, and the majority of service requests are completed within one day. Website and personal interactions average 1,200 a day. The proportion of service provided through Teachers' secure member website grows each year, and more than 200,000 members are registered for online service.

The Quality Service Index (QSI) is our primary performance measurement. An independent company surveys a sample of members throughout the year about the quality of Teachers' pension service and communications.

QUALITY SERVICE INDEX
(on a scale of 0 to 10)

	2014	2013
Total QSI	**9.2**	9.1
Service QSI (85%)	**9.3**	9.2
Communications QSI (15%)	**8.8**	8.7

Teachers' service is also measured against leading pension plans worldwide through surveys of those plans conducted by CEM Benchmarking Inc., which ranks plan performance in various categories.

BENCHMARKING RESULTS – SERVICE LEVEL SCORE COMPARISON

	2013	2012	2011	2010
Ontario Teachers' Pension Plan	**92**	92	92	91
CEM world average	**75**	75	75	75
Peer group average	**80**	80	79	78
Canadian participants – average	**72**	72	70	70

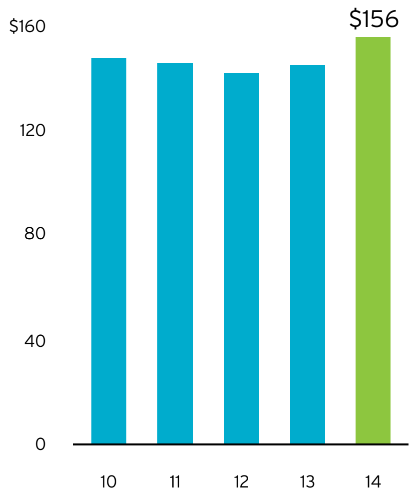
Note: Scores are based on fiscal year data using current survey weights.

Source: CEM Benchmarking Inc.

The cost per member was $156 in 2014, versus $145 in 2013.

The cost of administering the pension plan has been relatively stable in recent years. The 2014 increase reflects ongoing investments which must be made in systems and service channels to meet operational, regulatory and service requirements.

SERVICE COST PER MEMBER
For the years ended December 31 (Canadian $)



PLAN GOVERNANCE

Teachers' believes good governance is good business because it helps companies deliver long-term shareholder value. As a plan administrator, we measure ourselves against best practices for governance, internal controls, risk management and stewardship because this helps us deliver long-term value to members.

Since its inception, Teachers' has been overseen by independent, professional board members who are required to make decisions in the best interest of all beneficiaries of the plan. The plan sponsors, the Ontario government and OTF, each appoint four board members and they jointly select the chair. This governance structure plays a crucial role in the plan's success.

ROLE OF THE BOARD

The board oversees management of the pension fund and administration of the pension plan. Board members are professionals with financial expertise and are typically drawn from the fields of accounting, banking, business, economics, education and investment management.

Day-to-day investment management and plan administration are delegated to the President and CEO and his staff. No member of management is a board member.

Through five committees, board members review progress against management's stated objectives and confirm that management's strategies and decisions are in the best interests of all plan beneficiaries. The committees are Investment, Audit & Actuarial, Human Resources & Compensation, Governance and Benefits Adjudication.

Board members approve strategic plans, budgets, investment policies, risk appetite and asset mix, benchmarks, performance, compensation planning and succession plans. They monitor enterprise risks. They review and approve the audited consolidated financial statements.

In addition, the board oversees annual investment objectives and reviews transactions above pre-set limits. The board and management are responsible for investment decisions; the plan sponsors are not involved in such decisions.

The board conducts regular funding valuations to assess the pension plan's long-term financial health. The results of the funding valuations are reported to the plan sponsors. The board works closely with the independent actuary in setting the actuarial assumptions for these valuations, including the discount rate, with input from management and the plan sponsors. The Canadian Institute of Actuaries Standards of Practice require that each assumption is independently reasonable and that assumptions are appropriate in aggregate.

FOR MORE INFORMATION, VISIT OTPP.COM/GOVERNANCE

BOARD MEMBERS

Jean Turmel took over as board chair effective January 1, 2015, replacing Eileen Mercier, who retired after completing two terms as chair. Hugh Mackenzie completed his terms and Patsy Anderson resigned from the board in 2014. The sponsors named Bill Chinery, Steve McGirr and John Murray as new members.

Board and committee meeting attendance was 99% in 2014. Please visit otpp.com for full biographies of board members and committee mandates.

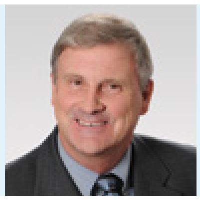
Jean Turmel, Chair

Appointed 2007; Chair since 2015

Attendance 96%

President, Perseus Capital Inc.; Board member, Canam Group Inc., Alimentation Couche-Tard Inc.

Former President, Financial Markets, Treasury and Investment Bank, National Bank of Canada



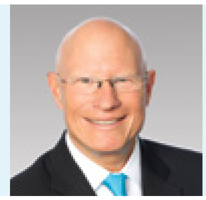
Rod Albert

Appointed 2010

Attendance 100%

Former President, Ontario Teachers' Federation; Former President and General Secretary of Ontario Secondary School Teachers' Federation

Benefits Adjudication*, Human Resources & Compensation and Governance Committees



Bill Chinery

FSA, FCIA

Appointed 2015

Former CEO, BlackRock Asset Management; Chair, Salvation Army Investment Committee; Chair, the Independent Review Committee for the Sun Life Investment Management Institutional Pooled Funds

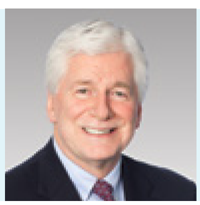
Human Resources & Compensation and Audit & Actuarial Committees, Lead Director – Information Technology

Steve McGirr

Appointed 2015

Former Senior EVP and Chief Risk Officer of CIBC; Member, Queen's University Cabinet; Director and Investment Committee chair of Wellspring, a cancer support network

Human Resources & Compensation and Governance* Committees

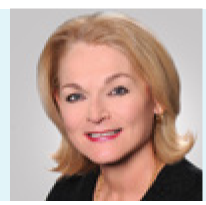


John Murray

Appointed 2014

Former Deputy Governor, Bank of Canada; Former assistant professor and visiting assistant professor, respectively, at the University of British Columbia and the University of North Carolina; Former lecturer, Princeton University

Audit & Actuarial and Governance Committees



Barbara Palk

CFA, FCSI, ICD.D

Appointed 2012

Attendance 100%

Board member, TD Asset Management USA Funds Inc.; Chair of the board of trustees at Queen's University; Director, First National Financial

Former President, TD Asset Management Inc.; Former Governance Chair, Canadian Coalition for Good Governance

Investment*, Benefits Adjudication** and Governance Committees

Sharon Sallows

ICD.D

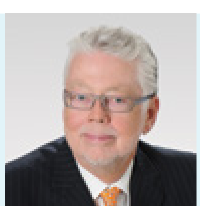
Appointed 2007

Attendance 95%

Director, Chartwell Seniors Housing REIT; Director, RioCan Real Estate Investment Trust

Former Senior Vice-President, Bank of Montreal

Human Resources & Compensation* and Audit & Actuarial Committees



David Smith

FCPA, FCA, ICD.D

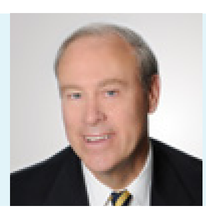
Appointed 2009

Attendance 100%

Chair, Government of Canada's Audit Committee

Former Chair and Senior Partner, PricewaterhouseCoopers; Former President & CEO, Canadian Institute of Chartered Accountants

Audit & Actuarial* and Governance Committees



Daniel Sullivan

Appointed 2010

Attendance 97%

Former Consul General of Canada in New York; Former Deputy Chairman, Scotia Capital; Former Chair and Director of the Toronto Stock Exchange; Former board member, Cadillac Fairview

Human Resources & Compensation and Audit & Actuarial Committees

*Committee Chair, ** Committee Vice-Chair

2014 HIGHLIGHTS

Board renewal was a key feature of 2014. A new chair and three new members were appointed by the plan sponsors to replace outgoing members. A new orientation and training program for new board members was launched in late 2014 to support their information needs.

Board members met 14 times in 2014 for board meetings and 12 times for Investment Committee meetings. In addition, the Governance Committee met three times, the Human Resources & Compensation Committee met 10 times, the Audit & Actuarial Committee met six times, and the Benefits Adjudication Committee held two general meetings and one appeal hearing.

Board members regularly hear from experts on investment and economic topics to ensure they are well briefed on important matters, including risks and opportunities.

ENTERPRISE RISK MANAGEMENT (ERM)

Through its regular operations, Teachers' is exposed to risks that could negatively affect achievement of the plan's objectives. These enterprise risks are broadly categorized as strategic, reputational, governance, investment and operational risks.

An ERM policy establishes the process through which management and employees identify, measure, manage and report risks. The ERM Committee, chaired by the President and CEO, provides executive-level oversight of the ERM program, which identifies potential events and risks as well as effective mechanisms to mitigate them. Highly ranked risks and mitigation strategies are reported to the board regularly.

The organization has multi-year programs in progress aimed at reducing enterprise risk, with a continued focus on operational risk. As part of these programs, business continuity, disaster recovery and crisis management plans are in place and are tested on a regular basis.

Board members approved an updated Investment Risk Appetite Statement in 2014. It articulates the board's tolerance for various investment-related risks senior management face when pursuing Teachers' strategic objectives. A summary of the statement is available on otpp.com.

LEGISLATIVE UPDATE

Compliance and advocacy

Teachers' must comply with federal and provincial legislation and investment regulations that govern registered pension plans in Ontario. It also has to comply with various rules and regulations in countries where it invests. Due to the complexity and dynamic nature of applicable laws and regulations, the legal compliance program was reconfigured in 2014 to include new resources, policies, procedures and training.

In addition, the Government and Public Affairs department was formed in 2014 to guide the coordination of Teachers' interactions with government and ensure that advocacy efforts support the plan's corporate objectives. Advocacy efforts focus on three main areas:

- supporting Teachers' investment teams when dealing with government officials and navigating regulatory processes;
- helping to build a positive regulatory environment;
- maintaining Teachers' role as a thought leader on public policy issues.

Plan changes

In 2014, the pension plan was amended to permit payment of the commuted value of a post-retirement survivor benefit, provided the annual benefit payable or the commuted value does not exceed certain limits.

The pension plan was amended to introduce the concept of a short absence: an employer-approved leave of five or fewer consecutive school days. As of September 1, 2014, members automatically maintain service credit for short absences.

The Partners' Agreement was amended to allow a director to remain on the Ontario Teachers' Pension Plan Board for five consecutive terms where their initial term was to replace an existing director mid-term.

Changes to the *Pension Benefits Act* (PBA)

The PBA was amended in 2014 to clarify entitlement of common-law spouses to survivor pensions and to provide a discharge to the administrator for survivor pensions already paid.

The PBA was further amended to require plan administrators to provide biennial statements to former and retired members. Teachers' will be required to provide statements every two years beginning no later than July 1, 2017.

Effective January 1, 2015, teachers who terminate their membership in the pension plan can transfer the commuted value of their pension benefits to a plan elsewhere in Canada, even if Teachers' does not have a reciprocal agreement with that plan.

Effective January 1, 2016, plan administrators must file a Statement of Investment Policies and Procedures (SIPP) with the Financial Services Commission of Ontario. SIPPs must include information about whether and how environmental, social and governance factors are incorporated. The plan's SIPP currently includes this information. Effective July 1, 2016, the information must also be disclosed on member statements.

COMPENSATION DISCUSSION & ANALYSIS

The Compensation Discussion & Analysis explains Teachers' approach to compensation, the various elements of our pay programs and the remuneration paid to our named executive officers. In fiscal 2014, our named executives were:

Ron Mock, President and CEO;

David McGraw, Senior Vice-President (SVP) and CFO;

Neil Petroff, Executive Vice-President (EVP), Investments;

Wayne Kozun, SVP, Fixed Income & Alternative Investments;

Jane Rowe, SVP, Teachers' Private Capital.

Our compensation framework

Compensation philosophy and objectives

Teachers' compensation framework has been developed on a foundation of pay-for-performance. Our compensation programs consist of base salary, annual incentives, and long-term incentive and are structured to ensure that there is direct alignment between Teachers' total-fund net value added (after expenses) and the compensation paid to senior management.

Our philosophy and pay practices are based upon the following key objectives:

- attracting and retaining high-calibre employees;
- motivating and rewarding top performance, encouraging teamwork, aligning personal and organizational objectives and rewarding successful performance over the long term;
- measuring and monitoring our investment incentive compensation framework relative to our risk budget and ensuring our compensation programs do not encourage excessive risk-taking.

Benchmarking process

Given the varied employment opportunities at Teachers', executive and non-executive positions are compared against relevant job groups and incentive programs in like markets. Our objective is to be competitive with those organizations against which we compete directly for talent. We target our total direct compensation at the median of our peers for target performance, and at the top quartile of our peers for exceptional performance. Our peer group includes other major Canadian pension funds, banks, insurance companies, and investment managers. For certain positions, we also compare to the general financial industry in Canada as well as U.S., U.K. and Hong Kong investment management organizations.

Design principles

The key design principle impacting each employee's incentive pay, at varying degrees, is our risk budget. At the beginning of each year, board members approve the active risk allocations for the total fund and each investment department, which in turn establish expected annual dollar value-added performance goals (i.e., dollars earned versus benchmark dollars earned) for the year. Actual investment performance at the total-fund and departmental levels (measured in dollars of value added after expenses) is compared against the expected performance goals. Additional measures used to monitor, assess and mitigate risk in our incentive programs include:

- setting an upper limit on individual annual incentive payments;
- modelling and testing our annual and long-term incentives under multiple performance scenarios in order to ensure that the payouts align with expected performance outcomes;
- comprehensive balanced scorecards that measure progress against strategic objectives across each division/department including risk management initiatives;
- clawback provisions stating that employees committing willful acts of dishonesty, fraud or theft shall be required to pay back to Teachers' all amounts paid to the participant under the AIP and/or LTIP.

Changes to Teachers' compensation program

In 2014, we undertook a comprehensive review of our compensation program to assess whether it continues to align with Teachers' strategic goals, is market competitive and drives the desired behavioural outcomes for Teachers' continued success. This review will continue throughout 2015.

Independent advisors

In 2014, board members retained the services of McLagan, an independent compensation consultant, to assist with the review of and recommended changes to the compensation program.

Elements of our compensation program – Overview

Our compensation program comprises base salary, annual incentives, and long-term incentive for non–bargaining unit employees.

Compensation structures for bargaining unit staff have been negotiated into the collective agreement. The four-year agreement runs through to December 31, 2017.

During 2014, salaries, incentives and benefits for 1,109 employees were $300.5 million.

Base salary

Base salaries compensate employees for fulfilling their day-to-day responsibilities and are reviewed annually. Each employee at Teachers' is assigned a job level with a corresponding salary grade that is designed to provide market-competitive pay commensurate with the employee's responsibilities, demonstrated skills, knowledge and track record of performance.

Annual Incentive Plan (AIP)

Our AIP rewards employees with cash awards based on business and individual performance results relative to pre-approved financial and non-financial measures. All non-union employees participate in the AIP. Weightings for each element vary for Investment, Corporate and Member Services employees. Detailed below are the components used to measure our named executive officers' performance within the AIP:

Performance Measure	President and CEO	SVP and CFO	EVP, Investments	SVP, Investments
Teachers' Performance	√	√	√	√
Division/Department Performance		√	√	√
Four-Year Total-Fund Performance	√		√	√
Four-Year Investment Department Performance				√
Individual Performance	√	√	√	√

Deferred Incentive Plan (DIP)

Employees can generally choose to allocate all or a portion of their AIP payment to either a Total-Fund Plan or a Private Capital Plan, or a combination of the two, for up to two years. The deferred amount will increase or decrease in value over the two-year deferral period based on actual rates of return of the respective plan.

Long-Term Incentive Plan (LTIP)

Our LTIP is designed to reward participating employees for delivering total-fund net value added (after expenses) and positive actual returns, net of costs, over the long term. Each year, a small percentage of the year's total-fund net value added (after expenses) will fund an LTIP pool, which is allocated to participating employees' notional accounts. In years when total-fund net value added (after expenses) is negative, participating employees will not share in any gains until further cumulative positive performance, net of expenses, mitigates the loss. Individual LTIP accounts are adjusted annually based on the total-fund actual rate of return. Each April, 25% of individual account balances are paid to active employees.

LTIP eligible employees include Investment employees at the assistant portfolio manager level and above; and Corporate and Member Services employees at the director level and above.

Mix of pay

Investment, Corporate, and Member Services employees have different percentages of their compensation tied to our variable pay programs. Recognizing their direct influence on investment results, investment professionals, including our CEO, have a greater percentage of their total direct compensation (base salary, annual incentive, and long-term incentive) tied to our variable pay programs. Detailed below is the target total direct compensation mix for our named executive officers. The actual pay mix realized may be different depending upon Teachers', divisional, and investment performance and the named executive officers' individual performance.

		Variable		
Position	Base Salary	Annual Incentive	Long-Term Incentive	% of Target Total Compensation Which Is Variable
President and CEO	25%	37.5%	37.5%	75%
SVP and CFO	45%	27.5%	27.5%	55%
EVP, Investments	25%	37.5%	37.5%	75%
SVP, Investments	27%	33%	40%	73%

Benefits and other compensation

Teachers' provides a competitive benefit program that includes life insurance, disability, health and dental benefits, vacation and other leave policies and an Employee Assistance Program. Teachers' retirement benefit for employees is a defined benefit pension plan described on page 28.

Executive employment contracts

There are no executive employment contracts or severance guarantees in place.

Compensation decisions made in 2015 reflecting 2014

How decisions are made

Annually, the board members and the CEO agree on the key financial and non-financial objectives comprising the CEO's individual performance measures. At the end of the year, the board members evaluate the CEO's performance relative to the annual objectives and responsibilities and assign an overall performance rating. The CEO's individual performance rating, Teachers' performance and total-fund performance are all considered when the board determines the CEO's total direct compensation.

Similar to the CEO, senior officers establish individual performance goals annually, and at year end they are evaluated relative to these goals. The outcome of individual goals and other performance measures as previously noted informs the total direct compensation recommendations for senior officers which are presented to and approved by the board members.

2014 performance results

Teachers' performance

To ensure we stay focused on our mission to provide outstanding service and retirement security to our members today and tomorrow, we prepare an enterprise scorecard comprising financial and non-financial goals and measures for four categories. The scorecard ensures we take a balanced view of key areas that will drive us to achieve our short-, medium-, and long-term goals. Below is a description of the four categories:

- *Retirement Security* includes rate of return and net value added;
- *Members and Stakeholders* includes plan governance, member satisfaction and service quality;
- *Operations* includes cost, efficiency, and risk measures;
- *People* includes initiatives to attract and retain the best talent.

At the end of the year, the scorecard is evaluated and the results are presented and approved by the board members. For 2014, we delivered above-target performance with a multiplier of 1.74 out of 2.

Four-year total-fund investment performance

The table below summarizes, at the total-fund level, the net value added (after expenses) performance for 2011 through to 2014 relative to the return on risk targets less cost allowance. Over the four-year cumulative period, we outperformed our target total-fund net value added (after expenses) by $4.05 billion, resulting in the maximum performance multiplier of 2.0x target.

Year	Total-Fund Net Value Added	Target	Multiplier
2011	$1.21 billion	$0.72 billion	1.67x
2012	$1.95 billion	$0.72 billion	2.72x
2013	$1.81 billion	$0.72 billion	2.52x
2014	$2.04 billion	$0.80 billion	2.55x
Four-Year	$7.01 billion	$2.96 billion	2.00x (maximum)

Four-year investment department performance

The table below summarizes performance in terms of net value-added dollars (after expenses) earned relative to the return required on the four-year risk allocation for each of the respective investment departments listed below:

Year	Public Equities	Private Capital	Infrastructure	Fixed Income & Alternative Investments	Tactical Asset Allocation & Natural Resources
2011 to 2014	Below target	Above target	Above target	Above target	Above target

Executive compensation

The compensation table represents disclosure of base salary, annual incentive, long-term incentive and other compensation earned in 2012, 2013 and 2014 by the CEO, the CFO and the three other most highly compensated executives, excluding subsidiary companies.

Name and Principal Position	Year	Base Salary A	Annual Incentive B	Long-Term Incentive Allocation C	Long-Term Incentive Paid D	Other[1] E	Change in Pension Value	**Total Direct Compensation[2] A+B+C**	Total Compensation[3] A+B+D+E
Ron Mock	2014	$498,654	$1,321,500	$1,800,000	$1,961,700	$1,185	$1,906,900	**$3,620,154**	$3,783,039
President and CEO	2013	322,346	787,900	900,000	1,802,800	703		**2,010,246**	2,913,749
	2012	310,385	788,400	1,300,000	1,896,600	447		**2,398,785**	2,995,832
David McGraw	2014	344,231	345,700	475,000	660,500	2,106	367,400	**1,164,931**	1,352,537
SVP and CFO	2013	332,692	335,700	420,000	646,000	725		**1,088,392**	1,315,117
	2012	322,692	348,500	440,000	650,300	464		**1,111,192**	1,321,956
Neil Petroff	2014	466,538	1,291,900	1,800,000	2,722,300	1,108	1,415,600	**3,558,438**	4,481,846
EVP, Investments	2013	451,538	1,293,300	1,780,000	2,709,900	984		**3,524,838**	4,455,722
	2012	436,539	1,268,500	1,850,000	2,722,500	628		**3,555,039**	4,428,167
Wayne Kozun	2014	331,923	808,100	1,037,800	1,832,200	788	878,300	**2,177,823**	2,973,011
SVP, Fixed Income	2013	322,808	775,900	900,000	1,875,600	704		**1,998,708**	2,975,012
& Alternative	2012	313,654	667,300	1,030,000	1,984,100	451		**2,010,954**	2,965,505
Investments									
Jane Rowe	2014	332,154	809,100	1,450,000	1,246,900	799	260,300	**2,591,254**	2,388,953
SVP, Teachers'	2013	323,115	778,300	875,000	1,054,700	704		**1,976,415**	2,156,819
Private Capital	2012	310,385	788,400	1,300,000	1,004,800	576		**2,398,785**	2,104,161

[1] Other compensation includes one or more of the following: group term life insurance, accidental death & dismemberment, and unused vacation cashout.

[2] When making compensation decisions, the board and management focus on Total Direct Compensation (TDC), which reflects base salary, annual incentive and long-term incentive allocation.

[3] Change in pension value and long-term incentive allocation are not included in total compensation.

Notional account balances

The table below outlines the notional account balances for each of our named executives.

Notional Account Activity

Name and Principal Position	Opening Balance	2014 Rate of Return	January 1, 2015 Allocation	2015 Payment	Balance
Ron Mock President and CEO	$5,408,454	11.8%	$1,800,000	$1,961,700	$5,885,222
David McGraw SVP and CFO	1,938,104	11.8%	475,000	660,500	1,981,397
Neil Petroff EVP, Investments	8,129,561	11.8%	1,800,000	2,722,300	8,166,956
Wayne Kozun SVP, Fixed Income & Alternative Investments	5,626,667	11.8%	1,037,800	1,832,200	5,496,496
Jane Rowe SVP, Teachers' Private Capital	3,163,958	11.8%	1,450,000	1,246,900	3,740,563

Retirement benefits

Teachers' employees participate in the Public Service Pension Plan (PSPP) and Public Service Supplementary Plan (PSSP), or the OPSEU Pension Plan, all of which are defined benefit plans.

Employees with pensionable earnings in excess of *Income Tax Act* (ITA) regulations also participate in a non-registered, unfunded Supplemental Employee Retirement Plan (SERP). For roles at the vice-president level or above, a portion of their annual incentive may be included as pensionable earnings.

The table below outlines the estimated present value of the total pension from all sources (PSPP, PSSP and SERP) and estimated annual pension benefits at age 65 for the Chief Executive Officer, the Chief Financial Officer and the three other most highly compensated executives, excluding subsidiary companies.

Name and Principal Position	Projected Years of Service at Age 65	Estimated Total Annual Pension Benefit at Age 65	Present Value of Total Pension at January 1, 2014	2014 Compensatory Annual Change in Pension Value	2014 Non-Compensatory[1] Annual Change in Pension Value	Present Value of Total Pension at December 31, 2014
Ron Mock President and CEO	17	$375,500	$2,210,800	$1,454,200	$452,700	$4,117,700
David McGraw SVP and CFO	17	177,800	1,022,200	138,600	228,800	1,389,600
Neil Petroff EVP, Investments	32	833,000	5,184,700	259,100	1,156,500	6,600,300
Wayne Kozun SVP, Fixed Income & Alternative Investments	36	677,000	2,512,800	102,300	776,000	3,391,100
Jane Rowe SVP, Teachers' Private Capital	13	191,900	460,000	135,000	125,300	720,300

[1] Non-compensatory changes include interest on liabilities and impact of any assumption changes.

The values shown above are estimated based on assumptions and represent entitlements that may change over time.

Board and committee member remuneration

In 2014, board members retained the services of Mercer, an independent compensation consultant, to conduct an assessment of board member remuneration. Changes were made in September to increase the annual retainers for all board members by $5,000 each.

Each board member receives an annual retainer of $70,000. The Chair of the Board receives an annual retainer of $170,000. The Chairs of the Investment, Governance, Human Resources & Compensation, Benefits Adjudication and Audit & Actuarial Committees receive additional retainers of $15,000 each. Board members who are appointed to more than three committees or who are in their first year of tenure receive an additional $5,000 retainer.

Board members are reimbursed for normal expenses for travel, meals and accommodation, as required. For 2014, these expenses totalled $82,000.

Board Member		Board Meetings	Committee Meetings	2014 Total Remuneration
Eileen Mercier	Chair of the Board	14	31	$166,250
Rod Albert	Chair, Benefits Adjudication Committee	14	21	82,450
Patsy Anderson[1]	Lead Director, Information Technology	6	12	40,000
Hugh Mackenzie	Chair, Human Resources & Compensation Committee	14	25	81,250
Barbara Palk	Vice-Chair, Benefits Adjudication Committee	14	24	72,450
Sharon Sallows	Chair, Governance Committee	13	24	86,250
David Smith	Chair, Audit & Actuarial Committee	14	28	86,250
Daniel Sullivan		14	24	66,250
Jean Turmel	Chair, Investment Committee	13	30	81,250

[1] Patsy Anderson resigned in July 2014.

FINANCIAL REPORTING

The Financial Reporting section highlights sections of the financial statements that management views as key to understanding the financial position of the plan.

Included in the pages preceding the consolidated financial statements are three letters that describe the responsibility of management, the auditors and the actuaries:

- Management's Responsibility for Financial Reporting – identifies that management is responsible for preparation of the financial statements. The financial statements are prepared according to Canadian accounting standards for pension plans. The board, which is independent from management, has ultimate responsibility for the financial statements and is assisted in its responsibility by the Audit & Actuarial Committee.
- Auditor's Report to the Administrator – the formal opinion issued by an external auditor on the consolidated financial statements.
- Actuaries' Opinion – identifies that valuation methods are appropriate, data is sufficient and reliable and the assumptions are in accordance with accepted actuarial practices. The actuarial valuation is based on membership data, accounting standards, and long-term interest rates.

FINANCIAL STATEMENT VALUATION

The financial statement valuation measures the fair value of the plan's net assets available for benefits and pension liabilities at a point in time. The financial statement valuation provides a snapshot of the financial health of the plan as it does not assume any future contributions and does not project the cost of benefits that current members have not yet earned. The financial statement valuation is therefore not considered an indicator of the long-term sustainability of the plan and not used by the plan sponsors to set contribution rates and benefit levels.

Methods and assumptions used for the financial statement valuation

The financial statement valuation is prepared in accordance with guidance from Chartered Professional Accountants of Canada (CPA Canada). The pension liabilities, prepared by an independent actuary, take into account pension credit earned to date by all plan members and contributions already received by the plan. Valuation techniques, estimates and pension liabilities are described further in the notes to the consolidated financial statements.

The actuarial assumptions used in determining the pension liabilities reflect best estimates of future economic and non-economic factors proposed by management and approved by the plan's board. Actual experience typically differs from these assumptions, and the differences are recognized as experience gains and losses in future years.

The discount rate for the financial statements is based on market rates, as at the valuation date, of bonds issued by the Province of Ontario, which have characteristics similar to the plan's liabilities. In 2014, the cash flow-based estimation methodology for determining the discount rate was adopted as it applies a weighted average discount rate that reflects the estimated timing and amount of benefit payments and is considered more accurate than the previous approach. The discount rate used is 3.35% (4.20% in 2013). Further details on the methods and assumptions used can be found in note 4 of the plan's consolidated financial statements.

FINANCIAL POSITION AS AT DECEMBER 31, 2014

The plan ended 2014 with a financial statement deficit of $18.2 billion, up from the deficit of $7.8 billion at the end of 2013. The deficit represents the difference between net assets available for benefits of $154.5 billion and accrued pension liabilities of $172.7 billion at year end.

YEAR-END FINANCIAL POSITION

As at December 31 (Canadian $ billions)	**2014**	2013
Net assets available for benefits	**$ 154.5**	$ 140.8
Accrued pension benefits	**(172.7)**	(148.6)
Deficit	**$ (18.2)**	$ (7.8)

During 2014, net assets available for benefits increased by $13.7 billion. Investment income of $16.3 billion and contributions of $3.2 billion increased net assets available for benefits while benefits paid of $5.3 billion and administrative expenses of $0.5 billion decreased the net assets available. Investment income of $16.3 billion was due primarily to strong equity, fixed income, and real asset returns partially offset by negative commodity returns (investment returns are discussed in the Investments section of the MD&A).

NET ASSETS AVAILABLE FOR BENEFITS

As at December 31 (Canadian $ billions)	**2014**	2013
Net assets available for benefits, beginning of year	**$ 140.8**	$ 129.5
Investment income	**16.3**	13.7
Contributions	**3.2**	3.1
Benefits paid	**(5.3)**	(5.1)
Administrative expenses	**(0.5)**	(0.4)
Increase in net assets available for benefits	**13.7**	11.3
Net assets available for benefits, end of year	**$ 154.5**	$ 140.8

Accrued pension benefits increased by $24.1 billion during the year to $172.7 billion. Changes in actuarial assumptions (mainly a decrease in the discount rate of 85 basis points) increased the accrued pension benefits amount by $18.3 billion. Benefits paid during 2014 of $5.3 billion include the addition of 4,600 retirement and disability pensions and 900 survivor pensions during 2014, as well as a 0.9% cost-of-living increase.

ACCRUED PENSION BENEFITS

As at December 31 (Canadian $ billions)	**2014**	2013
Accrued pension benefits, beginning of year	**$ 148.6**	$ 166.0
Interest on accrued pension benefits	**6.2**	5.6
Benefits accrued	**4.4**	5.0
Benefits paid	**(5.3)**	(5.1)
Changes in actuarial assumptions	**18.3**	(22.0)
Changes in level of conditional indexing	**0.4**	–
Experience losses/(gains)	**0.1**	(0.9)
Increase/(decrease) in accrued pension benefits	**24.1**	(17.4)
Accrued pension benefits, end of year	**$ 172.7**	$ 148.6

FAIR VALUE HIERARCHY

The plan's investments and investment-related liabilities are stated at fair value. The objective of fair value determination is to estimate an exit price at which an orderly transaction to sell the asset or to transfer the liability would take place between market participants. Valuation techniques are employed in order to measure fair value. As described in note 1c of the plan's consolidated financial statements, these techniques utilize inputs such as prices for market transactions, discount rates, contractual or expected future cash flows and other relevant factors that impact the assessment of fair value.

As required under Canadian accounting standards, the plan has classified and disclosed its fair value measurements into one of three categories based upon the degree of observable inputs used in their determination. Level 1 inputs consist of quoted prices in active markets for identical assets or liabilities; Level 2 inputs are derived from observable prices but do not meet the Level 1 criteria, while Level 3 inputs are unobservable. If different levels of inputs are used to measure the fair value of an investment, the classification within the hierarchy is based upon the lowest level input that is significant to the fair value measurement.

Level 1 net investments comprise the majority of the plan's government bonds and publicly traded equities, including these securities that are sold but not yet purchased, which are valued using quoted prices. Examples of Level 2 net investments include marketable corporate bonds that are valued using quoted prices from less actively traded markets and securities purchased under agreements to resell and securities sold under agreements to repurchase, which are valued using discounted cash flows and observable market yields. Examples of Level 3 investments include real assets such as real estate and infrastructure, non-publicly traded equities, and natural resource investments, which are valued using appropriate techniques that involve the use of significant unobservable inputs such as forecasted cash flows or other information that is specific to the entity.

The table below shows the plan's net investments based on the fair value hierarchy. Further details of each category can be found in note 2a of the plan's consolidated financial statements.

For the year ended December 31, 2014 (Canadian $ millions)	Level 1	Level 2	Level 3	**Total**
Fixed income	$ 75,492	$ 7,961	$ 13,816	**$ 97,269**
Equity	34,862	357	22,354	**57,573**
Natural resources	–	–	2,867	**2,867**
Real assets	2,551	270	36,433	**39,254**
Net investment-related receivables/(liabilities)	(16,408)	(26,237)	(1,932)	**(44,577)**
Net investments	$ 96,497	$ (17,649)	$ 73,538	**$ 152,386**

EFFECTIVE OVERSIGHT AND CONTROLS

Disclosure and financial reporting controls

We take guidance from National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings, issued by the Canadian Securities Administrators, as part of our commitment to good governance practices. The President and CEO, and the Senior Vice-President and Chief Financial Officer (CFO) are responsible for establishing and maintaining disclosure controls and procedures, and internal control over financial reporting.

We have designed disclosure controls and procedures to provide reasonable assurance that material information related to the plan is gathered and reported to management in order to allow timely decisions regarding public disclosure. We evaluated our disclosure controls and procedures and concluded as at December 31, 2014, that they are effective.

We have also designed internal control over financial reporting, using the Integrated Framework updated in 2013 by the Treadway Commission's Committee of Sponsoring Organizations (the COSO Framework), to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with Canadian Generally Accepted Accounting Principles. We have evaluated the effectiveness of the plan's internal control over financial reporting and concluded they are effective as at year end.

Protecting audit quality and integrity

A key oversight activity of audit committees is annually assessing the effectiveness of the external auditor. This helps audit committees meet their responsibility to make informed recommendations to the board on whether or not to reappoint the external auditor. Teachers' has conducted assessments annually. In 2014, an "Enhancing Audit Quality" initiative developed by the Chartered Professional Accountants of Canada, the Canadian Public Accountability Board and the Institute of Corporate Directors resulted in the issuance of two publications: (1) Annual Assessment of the External Auditor – Tool for Audit Committees; and (2) Periodic Comprehensive Review of the External Auditor – Tool for Audit Committees. In 2014, Teachers' conducted a comprehensive review of its external auditor, and leveraged the tools provided in the publication as well as its prior annual assessments. Based on the review's findings, Teachers' Audit & Actuarial Committee recommended, and the board approved, the reappointment of the external auditor for 2014.

Teachers' and other corporate governance advocates have expressed concern over the years about accounting firms that audit public companies and also earn substantial revenue from those companies for non-audit consulting services. We believe that such consulting fees can compromise, or appear to compromise, the integrity of the audit function.

We strive to minimize our own use of consulting services involving the plan's auditor and we always disclose the total amount paid for such services. In 2014, fees paid to Deloitte Touche Tohmatsu Limited (of which the Canadian firm is the plan's auditor) totalled $9.4 million ($8.2 million in 2013), of which $8.7 million was for audit activities and $700,000 was for non-audit services. Of the $700,000 paid for non-audit services, approximately $30,000 related to the plan, $520,000 related to subsidiaries audited by Deloitte and the balance of $150,000 was for subsidiaries not audited by Deloitte. Of the $520,000 paid by the subsidiaries, $10,000 was paid to Deloitte (Canada) and $510,000 was paid to Deloitte firms outside of Canada, which are considered to have lower risk of impairing the independence of the plan's auditor.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The consolidated financial statements of the Ontario Teachers' Pension Plan have been prepared by management, which is responsible for the integrity and fairness of the data presented, including the many amounts which must, of necessity, be based on estimates and judgments. The accounting policies followed in the preparation of these consolidated financial statements conform to Canadian accounting standards for pension plans. Financial information presented throughout the annual report is consistent with the consolidated financial statements.

Systems of internal control and supporting procedures are maintained to provide assurance that transactions are authorized, assets safeguarded and proper records maintained. These controls include quality standards in hiring and training of employees, a code of conduct, the establishment of an organizational structure that provides a well-defined division of responsibilities and accountability for performance, and the communication of policies and guidelines through the organization.

Ultimate responsibility for the consolidated financial statements rests with the members of the Board. The Board is assisted in its responsibilities by the Audit & Actuarial Committee (the Committee), consisting of five Board members who are not officers or employees of the Plan administrator. In addition, the Committee reviews the recommendations of the internal and external auditors for improvements in internal control and the action of management to implement such recommendations. In carrying out its duties and responsibilities, the Committee meets regularly with management and with both the external and internal auditors to review the scope and timing of their respective audits, to review their findings and to satisfy itself that their responsibilities have been properly discharged. This Committee reviews the consolidated financial statements and recommends them for approval by the Board.

The Plan's external auditor, Deloitte LLP, is directly accountable to the Audit & Actuarial Committee and has full and unrestricted access to the Committee. They discuss with the Committee their audit and related findings as to the integrity of the Plan's financial reporting and the adequacy of internal control systems. The Plan's external auditor has conducted an independent examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards, performing such tests and other procedures as they consider necessary to express the opinion in their Report to the Administrator.

Ron Mock
President and Chief Executive Officer
March 5, 2015

David McGraw
Senior Vice-President and Chief Financial Officer

AUDITOR'S REPORT TO THE ADMINISTRATOR

We have audited the accompanying consolidated financial statements of Ontario Teachers' Pension Plan Board, which comprise the consolidated statements of financial position as at December 31, 2014, and the consolidated statements of changes in net assets available for benefits, consolidated statements of changes in accrued pension benefits and consolidated statements of changes in deficit for the year then ended and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

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

Auditor's responsibility

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

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

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

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Ontario Teachers' Pension Plan Board as at December 31, 2014, and the changes in its net assets available for benefits, changes in accrued pension benefits and changes in deficit for the year then ended in accordance with Canadian accounting standards for pension plans.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
Licensed Public Accountants
March 5, 2015

ACTUARIES' OPINION

Mercer (Canada) Limited was retained by the Ontario Teachers' Pension Plan Board (the Board) to perform an actuarial valuation of the going concern liabilities of the Ontario Teachers' Pension Plan (the Plan) as at December 31, 2014, for inclusion in the Plan's consolidated financial statements. As part of the valuation, we examined the Plan's recent experience with respect to the non-economic assumptions and presented our findings to the Board.

The valuation of the Plan's actuarial liabilities was based on:

- membership data provided by the Ontario Teachers' Pension Plan Board as at August 31, 2014;
- methods prescribed by Section 4600 of the Chartered Professional Accountants of Canada Handbook for pension plan financial statements;
- real and nominal interest rates on long-term bonds at the end of 2014;
- assumptions about future events (for example, future rates of inflation and future retirement rates) which have been communicated to us as the Board's best estimate of these events; and
- information obtained from the Ontario Ministry of Labour and other published data, where applicable, on wage rate changes.

The objective of the consolidated financial statements is to fairly present the financial position of the Plan on December 31, 2014, as a going concern. This is different from the statutory valuation (the actuarial valuation required by the *Pension Benefits Act (Ontario)*), which establishes a prudent level for future contributions.

While the actuarial assumptions used to estimate liabilities for the Plan's consolidated financial statements represent the Board's best estimate of future events and market conditions at the end of 2014, and while in our opinion these assumptions are reasonable, the Plan's future experience will inevitably differ, perhaps significantly, from the actuarial assumptions. Any differences between the actuarial assumptions and future experience will emerge as gains or losses in future valuations, and will affect the financial position of the Plan, and the contributions required to fund it, at that time.

We have tested the data for reasonableness and consistency, and we believe it to be sufficient and reliable for the purposes of the valuation. We also believe that the methods employed in the valuation are appropriate for the purposes of the valuation, and that the assumptions used in the valuation are in accordance with accepted actuarial practice. Our opinions have been given, and our valuation has been performed, in accordance with accepted actuarial practice in Canada.

Scott Clausen, F.C.I.A., F.S.A
March 5, 2015

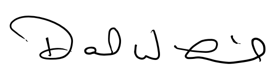
Lise Houle, F.C.I.A., F.S.A

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at December 31 (Canadian $ millions)	**2014**	2013
Net assets available for benefits		
ASSETS		
Cash	**$ 129**	$ 67
Receivable from the Province of Ontario (note 3)	**3,098**	2,965
Receivable from brokers	**49**	46
Investments (note 2)	**225,172**	198,109
Premises and equipment	**44**	32
	228,492	201,219
LIABILITIES		
Accounts payable and accrued liabilities	**295**	333
Due to brokers	**935**	916
Investment-related liabilities (note 2)	**72,786**	59,206
	74,016	60,455
Net assets available for benefits	**$ 154,476**	$ 140,764
Accrued pension benefits and deficit		
Accrued pension benefits (note 4)	**$ 172,725**	$ 148,571
Deficit	**(18,249)**	(7,807)
Accrued pension benefits and deficit	**$ 154,476**	$ 140,764

On behalf of the Plan administrator:

Chair



Board Member

CONSOLIDATED STATEMENTS OF CHANGES IN NET ASSETS AVAILABLE FOR BENEFITS

For the year ended December 31 (Canadian $ millions)	**2014**	2013
Net assets available for benefits, beginning of year	**$ 140,764**	$ 129,524
Investment operations		
Net investment income (note 6)	**16,260**	13,718
Administrative expenses (note 11a)	**(409)**	(364)
Net investment operations	**15,851**	13,354
Member service operations		
Contributions (note 9)	**3,216**	3,081
Benefits paid (note 10)	**(5,306)**	(5,150)
Administrative expenses (note 11b)	**(49)**	(45)
Net member service operations	**(2,139)**	(2,114)
Increase in net assets available for benefits	**13,712**	11,240
Net assets available for benefits, end of year	**$ 154,476**	$ 140,764

CONSOLIDATED STATEMENTS OF CHANGES IN ACCRUED PENSION BENEFITS

For the year ended December 31 (Canadian $ millions)	2014	2013
Accrued pension benefits, beginning of year	**$ 148,571**	$ 166,009
Increase in accrued pension benefits		
Interest on accrued pension benefits	**6,239**	5,642
Benefits accrued	**4,367**	4,992
Changes in actuarial assumptions and methods (note 4a)	**18,264**	–
Changes in level of conditional indexing (note 4b)	**451**	–
Experience losses (note 4c)	**139**	–
	29,460	10,634
Decrease in accrued pension benefits		
Benefits paid (note 10)	**5,306**	5,150
Changes in actuarial assumptions and methods (note 4a)	**–**	21,973
Experience gains (note 4c)	**–**	949
	5,306	28,072
Net increase/(decrease) in accrued pension benefits	**24,154**	(17,438)
Accrued pension benefits, end of year	**$ 172,725**	$ 148,571

CONSOLIDATED STATEMENTS OF CHANGES IN DEFICIT

For the year ended December 31 (Canadian $ millions)	2014	2013
Deficit, beginning of year	**$ (7,807)**	$ (36,485)
Increase in net assets available for benefits	**13,712**	11,240
Net (increase)/decrease in accrued pension benefits	**(24,154)**	17,438
Deficit, end of year	**$ (18,249)**	$ (7,807)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the year ended December 31, 2014

DESCRIPTION OF PLAN

The following description of the Ontario Teachers' Pension Plan (the Plan) is a summary only. For more complete information, reference should be made to the *Teachers' Pension Act (Ontario)* (the TPA) as amended.

(a) General

The Plan is governed by the TPA. It is a contributory defined benefit pension plan co-sponsored by the Province of Ontario (the Province) and Plan members, represented by Ontario Teachers' Federation (OTF) (the co-sponsors). The terms of the Plan are set out in Schedule 1 to the TPA.

The Plan is registered with the Financial Services Commission of Ontario (FSCO) and under the *Income Tax Act (Canada)* (the ITA) (registration number 0345785) as a Registered Pension Plan which is not subject to income taxes in Canada. The Plan may be liable for taxes in other jurisdictions where full tax exemptions are not available.

The Plan is administered and the investments are managed by the Ontario Teachers' Pension Plan Board (the Board). Under the TPA, the Board is constituted as a corporation without share capital to which the *Corporations Act (Ontario)* does not apply.

(b) Funding

Plan benefits are funded by contributions and investment earnings. Contributions are made by active members of the Plan and are matched by either the Province or designated employers. The determination of the value of the accrued pension benefits and required contributions is made on the basis of periodic actuarial valuations.

(c) Retirement pensions

A retirement pension is available based on the number of years of credited service, the average of the best five annual salaries and the age of the member at retirement. A member is eligible for a reduced retirement pension from age 50. An unreduced retirement pension is available at either age 65 or when the sum of a member's age and qualifying service equals 85.

(d) Disability pensions

A disability pension is available at any age to a disabled member with a minimum of 10 years of qualifying service. The type of disability pension is determined by the extent of the disability.

(e) Death benefits

Death benefits are available on the death of an active member and may be available on the death of a retired member. The benefit may take the form of a survivor pension, lump-sum payment or both.

(f) Escalation of benefits

Pension benefits are adjusted in January each year for inflation, subject to an upper limit of 8% and a lower limit of 0% in any one year with any excess above or below those limits carried forward. For credited service earned up to December 31, 2009, inflation protection is 100% of the change in the Consumer Price Index. Credited service earned after December 31, 2009, is subject to conditional inflation protection. For credited service earned between January 1, 2010, and December 31, 2013, the minimum indexation level is set at 50% of the change in the Consumer Price Index. There is no minimum level of inflation protection for credited service earned after 2013. The indexation level stated in the most recent funding valuation filing remains in effect until a subsequent filing updates the amount. Inflation protection of up to 100% for credited service earned after 2009 can be restored on a go-forward basis, depending on the Plan's funded status.

(g) Retirement Compensation Arrangement

Restrictions in the ITA and its regulations on the payment of certain benefits from the registered pension plan for periods of service after 1991 may impact some Plan members. To address affected members, the Retirement Compensation Arrangement (the RCA) was established by agreement between the co-sponsors as a supplementary plan to provide for these benefits. Examples of these benefits include: (1) members of the Plan who retired with average earnings above $149,714 (CPP-exempt members $138,500) in 2014 and $145,769 (CPP-exempt members $134,834) in 2013; and (2) members whose pensions would require a larger reduction for early retirement to comply with the ITA limitations than the Plan would impose. Because the RCA is a separate trust, the net assets available for benefits and accrued benefits and deficit of the RCA are not included in these consolidated financial statements.

NOTE 1.
SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of presentation

These consolidated financial statements are prepared in Canadian dollars, the Plan's functional currency, in accordance with the accounting standards for pension plans in Part IV of the Chartered Professional Accountants (CPA) Canada Handbook (Section 4600). Section 4600 provides specific accounting guidance on investments and pension obligations. For accounting policies that do not relate to either investments or pension obligations, the Plan must consistently comply with either International Financial Reporting Standards (IFRS) in Part I or accounting for private enterprises in Part II of the CPA Canada Handbook. The Plan has elected to comply with IFRS in Part I of the CPA Canada Handbook. To the extent that IFRS in Part I is inconsistent with Section 4600, Section 4600 takes precedence.

The Plan's real estate portfolio is comprised of real estate–related investments that are either owned or managed on behalf of the Plan by The Cadillac Fairview Corporation Limited (CFCL), a wholly owned subsidiary, which the Plan consolidates. The Plan also consolidates wholly owned investment holding companies that are managed by either the Plan or CFCL. Investment holding companies that are managed by external parties are recognized as the Plan's investment assets. Under Section 4600, investment assets, including those over which the Plan has control or significant influence, are measured at fair value and presented on a non-consolidated basis.

The consolidated financial statements for the year ended December 31, 2014, were authorized for issue through a resolution of the Board on March 5, 2015.

(b) Future changes in accounting policies

The relevant new guidance issued by the International Accounting Standards Board not yet adopted by the Plan includes:

- IFRS 9, Financial Instruments. The new standard will replace IAS 39, Financial Instruments: Recognition and Measurement, and includes guidance on recognition and derecognition of financial assets and financial liabilities, impairment and hedge accounting. The new standard will come into effect January 1, 2018, with early application permitted.

Management does not expect any significant impact on either the Plan's financial position or its investment income when adopting the new standard.

(c) Investments

Valuation of investments

Investments are either directly or indirectly owned by the Plan. Investment-related liabilities are incurred by the Plan directly. Details of investments and investment-related liabilities are presented in note 2a and are stated at fair value. Fair value is the price that would either be received to sell an asset or be paid to transfer a liability in an orderly transaction (i.e., an exit price) between market participants at the measurement date. In an active market, fair value is best evidenced by an independent quoted market price. In the absence of an active market, fair value is determined by valuation techniques that make maximum use of inputs observed from markets.

Fair values of investments are determined as follows:

a. Short-term investments are valued using either quoted closing mid-market prices or discounted cash flows based on current market yields, when quoted closing mid-market prices are unavailable.

b. Bonds, including both nominal and real return, are valued on the basis of quoted closing mid-market prices. If quoted closing mid-market prices are not available, estimated values are calculated using discounted cash flows based on current market yields and comparable securities, as appropriate.

c. Securities sold under agreements to repurchase and securities purchased under agreements to resell are valued using discounted cash flows based on current market yields.

d. Public equities are valued at quoted closing mid-market prices. When the market for a public equity is not active, management assesses whether the quoted prices represent fair value. If not, management adjusts the quoted prices or estimates the fair value by using appropriate techniques including valuation models.

e. Real estate, private equities, infrastructure, and natural resources are valued based on estimated fair values determined by using appropriate techniques and best estimates by either management, appraisers, or both. Where external appraisers are engaged to perform the valuation, management ensures the appraisers are independent and compares the assumptions used by the appraisers with management's expectations based on current market conditions and industry practice to ensure the valuation captures the business and economic conditions specific to the investment.

   At least 70% of the value of the rental property portfolio covering all product types and geographic regions is independently appraised annually. At a minimum, 90% of the real estate portfolio will be valued by independent appraisers at least every three years.

   Private equity funds are recorded at fair value based on net asset values obtained from each of the funds' administrators. These net asset values are reviewed by management.

f. Derivative financial instruments are recorded at fair value using market prices where available. Where quoted market values are not readily available, appropriate alternative valuation techniques are used to determine fair value. In determining fair value, consideration is also given to the credit risk of the counterparty.

g. Alternative investments, comprised of hedge funds and managed futures accounts, are recorded at fair value based on net asset values obtained from each of the funds' administrators. These net asset values are reviewed by management.

The Plan uses a number of valuation techniques to determine the fair value of investments for which observable prices in active markets for identical investments are not available. These techniques include: valuation methodologies based on observable prices for similar investments; present-value approaches where future cash flows generated by the investment are estimated and then discounted using a risk-adjusted interest rate; and option-pricing models. The principal inputs to these valuation techniques are listed below. Values between and beyond available data points may be obtained by interpolation and extrapolation.

- Bond prices – quoted prices are generally available for government bonds, certain corporate bonds and some other debt-related products.

- Credit spreads – where available, credit spreads are derived from prices of credit default swaps or other credit-based instruments, such as debt securities. For others, credit spreads are obtained from pricing services.

- Interest rates – principally derived from benchmark interest rates such as quoted interest rates from central banks and in swap, bond and futures markets. Benchmark interest rates are considered when determining discount rates used in the present-value approaches.

- Foreign currency exchange rates – there are observable markets, both spot and forward, and in futures in all major currencies.
- Public equity and equity index prices – quoted prices are generally readily available for equity shares listed on the stock exchanges and for indices on such shares.
- Commodity prices – many commodities are actively traded in spot, forward and futures markets.
- Price volatilities and correlations – volatility is a measure of the tendency of a specific price to change over time. Correlation measures the degree to which two or more prices or other variables are observed to have moved together historically. Volatility is an input in valuing options and certain products such as derivatives with more than one underlying variable that is correlation-dependent. Volatility and correlation values are either obtained from broker quotations, from pricing services, or are derived from quoted option prices.
- Forecasts on operating cash flows of real estate, private equities, infrastructure, and natural resources – forecasts include assumptions on revenue, revenue growth, expenses, capital expenditures, and capital structure. They are generally provided by either management of the companies in which the Plan invests or external managers. Additional assumptions from external parties, for example, external appraisers, may also be used in the forecast.

The Plan refines and modifies its valuation techniques as markets and products develop and the pricing for individual products becomes more transparent.

While the Plan believes its valuation techniques are appropriate and consistent with other market participants, the use of different techniques or assumptions could result in different estimates of fair value at the balance sheet date. Management has assessed and determined that using possible alternative assumptions will not result in significantly different fair values.

Fair value hierarchy

Investment assets and investment-related liabilities are classified and disclosed in one of the following categories reflecting the significance of inputs used in making the fair value measurement:

- Level 1 – quoted prices (unadjusted) in active markets for identical assets or liabilities;
- Level 2 – inputs other than quoted prices included within Level 1 that are observable for the assets or liabilities, either directly or indirectly; and
- Level 3 – unobservable inputs.

If different levels of inputs are used to measure the fair value of an investment, the classification within the hierarchy is based on the lowest level input that is significant to the fair value measurement.

Trade-date reporting

Purchases and sales of investments and derivative contracts are recorded as of the trade date.

Net investment income

Dividend income is recognized based on the ex-dividend date, and interest income and real estate income are recognized on the accrual basis as earned. Net investment income also includes both realized and unrealized gains and losses. Unrealized gains and losses are recognized only when the fair value of the investment is based on a quoted market price in an active market or a valuation using appropriate valuation techniques is performed and approved by management.

Transaction costs

Transaction costs are incremental costs directly attributable to the acquisition, issue or disposal of a financial asset or financial liability. Transaction costs are expensed as incurred. Any transaction amounts received by the Plan that are directly attributable to the acquisition of an investment are netted against transaction costs paid.

Management fees

Management and performance fees for external investment managers and administrators are expensed as incurred.

(d) Foreign currency translation

Assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rates prevailing on the year-end date. Income and expenses are translated into Canadian dollars at the exchange rates prevailing on the dates of the transactions. The realized and unrealized gains and losses arising from these translations are included within net realized and unrealized gains on investments in investment income.

(e) Accrued pension benefits

The value of accrued pension benefits and changes therein during the year are based on an actuarial valuation prepared by Mercer (Canada) Limited, an independent firm of actuaries. The valuation is made annually as at August 31 and then extrapolated to year end. It uses the projected benefit method pro-rated on service and management's best estimate, as at the valuation date, of various economic and non-economic assumptions.

As described in paragraph (f) of the Description of Plan note, the inflation protection benefits for credited service earned after December 31, 2009, is conditional, depending on the Plan's funded status. For the financial statement valuation, the Plan estimates the conditional inflation protection benefits based on the indexation levels stated in the most recent funding valuation filing.

(f) Contributions

Contributions from the members, the Province and designated employers are recorded on an accrual basis. Cash received from members for credited service and cash transfers from other pension plans are recorded when received.

(g) Benefits

Benefit payments to members and others, commuted value payments and refunds to former members, and transfer payments to other plans are recorded in the period in which they are paid. Any benefit payment accruals not paid are reflected in accrued pension benefits.

(h) Premises and equipment

Premises and equipment are recorded at cost and amortized on a straight-line basis over their estimated useful lives.

(i) Use of estimates

In preparing these consolidated financial statements, management uses estimates and assumptions that primarily affect the reported values of assets and liabilities, and related income and expenses. Estimates and assumptions are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable and relevant under the circumstances. The effect of a change in an estimate or assumption is recognized in the period in which the estimate or assumption is revised. Significant estimates and assumptions are used primarily in the determination of accrued pension benefits and the fair value of investments and investment-related receivables and liabilities. Note 4 explains how estimates and assumptions are used in determining accrued pension benefits and note 1c explains how estimates and assumptions are used to derive the fair value of investments and investment-related receivables and liabilities.

(j) Contingencies

A contingent liability is a possible obligation that depends on the occurrence or non-occurrence of one or more future events not controlled by the Plan. Contingent liabilities are not recognized but the nature and extent are disclosed in the notes to the consolidated financial statements. A provision for a present obligation is recognized when a reliable estimate can be determined and the settlement of the obligation is probable.

NOTE 2. INVESTMENTS

The Plan invests, directly or through derivatives, in fixed income, equities, natural resources and real asset investments in accordance with the Board's policy of asset diversification.

(a) Investments[1] before allocating the effect of derivative contracts

The schedule below summarizes the Plan's investments and investment-related liabilities, including net accrued interest and dividends of $500 million (2013 – $253 million), before allocating the effect of derivative contracts:

As at December 31		2014		2013
(Canadian $ millions)	**Fair Value**	**Cost**	Fair Value	Cost
Fixed income				
Bonds[2, 3]	**$ 51,250**	**$ 47,409**	$ 38,812	$ 38,660
Short-term investments[2, 3]	**5,495**	**5,477**	8,345	8,329
Alternative investments[2, 4]	**10,400**	**8,054**	8,018	6,576
Canadian real-rate products	**20,563**	**15,222**	18,598	15,263
Non-Canadian real-rate products	**9,561**	**7,698**	8,485	8,207
	97,269	**83,860**	82,258	77,035
Equity				
Publicly traded				
Canadian	**2,900**	**2,635**	3,292	3,130
Non-Canadian	**33,664**	**25,542**	30,891	23,031
Non-publicly traded				
Canadian[2]	**2,009**	**1,839**	2,254	2,151
Non-Canadian[2]	**19,000**	**14,840**	16,884	13,631
	57,573	**44,856**	53,321	41,943
Natural resources				
Timberland	**2,592**	**1,699**	2,446	2,078
Sector investment[5]	**275**	**276**	166	154
	2,867	**1,975**	2,612	2,232
Real assets				
Real estate (note 5)	**26,595**	**16,870**	23,572	14,461
Infrastructure	**12,659**	**10,079**	11,684	9,458
	39,254	**26,949**	35,256	23,919
	196,963	**157,640**	173,447	145,129
Investment-related receivables				
Securities purchased under agreements to resell	**24,136**	**23,754**	21,851	21,692
Cash collateral deposited under securities borrowing arrangements	**2,322**	**2,322**	1,279	1,279
Cash collateral paid under credit support annexes	**178**	**178**	–	–
Derivative-related, net	**1,573**	**1,066**	1,532	604
	28,209	**27,320**	24,662	23,575
Investments	**$ 225,172**	**$ 184,960**	$ 198,109	$ 168,704

[1] For additional details, refer to the Major Investments on page 68.

[2] Beginning in January 1, 2014, fund investments have been classified based on the type of fund and valuation methodology. 2013 comparative figures have been reclassified to reflect the change.

[3] Beginning in January 1, 2014, bonds with a maturity less than a year, previously classified as short-term investments, have been classified as bonds. 2013 comparative figures have been reclassified to reflect the change.

[4] Comprised primarily of hedge funds and managed futures accounts.

[5] Sector investment includes oil, gas and agricultural assets.

As at December 31		2014		2013
(Canadian $ millions)	**Fair Value**	**Cost**	Fair Value	Cost
Investment-related liabilities				
Securities sold under agreements to repurchase	**$ (45,260)**	**$ (44,846)**	$ (37,875)	$ (37,957)
Securities sold but not yet purchased				
Fixed income	**(16,522)**	**(14,431)**	(13,861)	(14,818)
Equities	**(2,291)**	**(2,090)**	(1,269)	(1,110)
Real estate (note 5)	**(4,507)**	**(4,147)**	(4,333)	(4,029)
Cash collateral received under credit support annexes	**(57)**	**(57)**	(317)	(317)
Derivative-related, net	**(4,149)**	**(1,411)**	(1,551)	(685)
	(72,786)	**(66,982)**	(59,206)	(58,916)
Net investments (note 2d)	**$ 152,386**	**$ 117,978**	$ 138,903	$ 109,788

(b) Fair value hierarchy

The schedule below presents the Plan's investments and investment-related liabilities within the fair value hierarchy as outlined in note 1c:

				December 31, 2014
(Canadian $ millions)	Level 1	Level 2	Level 3	**Total**
Fixed income	$ 75,492	$ 7,961	$ 13,816	**$ 97,269**
Equity	34,862	357	22,354	**57,573**
Natural resources	–	–	2,867	**2,867**
Real assets	2,551	270	36,433	**39,254**
Net investment-related receivables/(liabilities)	(16,408)	(26,237)	(1,932)	**(44,577)**
Net investments	$ 96,497	$ (17,649)	$ 73,538	**$ 152,386**

				December 31, 2013
(Canadian $ millions)	Level 1	Level 2	Level 3	Total
Fixed income[6]	$ 66,593	$ 4,529	$ 11,136	$ 82,258
Equity[6]	32,372	995	19,954	53,321
Natural resources	–	–	2,612	2,612
Real assets	965	280	34,011	35,256
Net investment-related receivables/(liabilities)	(14,107)	(18,779)	(1,658)	(34,544)
Net investments	$ 85,823	$ (12,975)	$ 66,055	$ 138,903

[6] Beginning in January 1, 2014, fund investments have been classified based on the type of fund and valuation methodology. 2013 comparative figures have been reclassified to reflect the change.

The schedule below presents a reconciliation of investments and net investment-related receivables/(liabilities) measured at fair value using significant unobservable inputs (Level 3) during the year. Realized and unrealized gains/(losses) are included in investment income.

						2014
(Canadian $ millions)	Fixed Income[8]	Equity[8]	Natural Resources	Real Assets	Net Investment-Related Receivables/ (Liabilities)	**Total**
Balance, beginning of year	$ 11,136	$ 19,954	$ 2,612	$ 34,011	$ (1,658)	**$ 66,055**
Purchases	5,173	5,763	295	6,238	5,063	**22,532**
Sales	(3,797)	(5,699)	(522)	(6,652)	(4,338)	**(21,008)**
Transfers in[7]	–	–	–	–	(12)	**(12)**
Transfers out[7]	–	–	–	–	1	**1**
Gains/(losses) included in investment income						
Realized	118	1,265	(30)	2,282	54	**3,689**
Unrealized	1,186	1,071	512	554	(1,042)	**2,281**
Balance, end of year	$ 13,816	$ 22,354	$ 2,867	$ 36,433	$ (1,932)	**$ 73,538**

						2013
(Canadian $ millions)	Fixed Income[8]	Equity[8]	Natural Resources	Real Assets	Net Investment-Related Receivables/ (Liabilities)	Total
Balance, beginning of year	$ 11,113	$ 15,182	$ 2,173	$ 29,321	$ (1,653)	$ 56,136
Purchases	3,766	3,686	155	3,958	2,783	14,348
Sales	(4,525)	(2,754)	(11)	(1,966)	(2,885)	(12,141)
Transfers in[7]	–	106	–	–	2	108
Transfers out[7]	(106)	(174)	–	–	–	(280)
Gains/(losses) included in investment income						
Realized	268	739	(4)	817	(19)	1,801
Unrealized	620	3,169	299	1,881	114	6,083
Balance, end of year	$ 11,136	$ 19,954	$ 2,612	$ 34,011	$ (1,658)	$ 66,055

[7] Transfers in and transfers out of Level 3 are due to the change in the availability of observable inputs used for fair value measurement of investment assets or related liabilities. Similarly, the transfers between Level 2 and Level 1 of $365 million (2013 – $250 million) are due to the change in the applicability of non-observable inputs. See note 1c Fair Value Hierarchy.

[8] Beginning in January 1, 2014, fund investments have been classified based on the type of fund and valuation methodology. 2013 comparative figures have been reclassified to reflect the change.

(c) Derivative contracts

Derivative contracts are financial contracts, the value of which is derived from the value of underlying assets, commodities, indices, interest rates or currency rates. Derivative contracts are transacted either in the over-the-counter (OTC) market or on regulated exchanges.

Notional amounts of derivative contracts represent the contractual amount to which a rate or price is applied for computing the cash to be paid or received. Notional amounts are the basis upon which the returns from, and the fair value of, the contracts are determined. They do not necessarily indicate the amounts of future cash flow involved or the current fair value of the derivative contracts and, therefore, do not indicate the Plan's exposure to credit or market risks. The derivative contracts become favourable (assets) or unfavourable (liabilities) as a result of fluctuations in either market rates or prices relative to their terms. The aggregate notional amounts and fair values of derivative contracts can fluctuate significantly.

Derivative contracts, transacted either in the OTC market or on regulated exchanges, include:

Swaps

Swaps are OTC contracts in which two counterparties exchange a series of cash flows based on agreed upon rates to a notional amount. The various swap agreements that the Plan enters into are as follows:

Equity and commodity swaps are contracts in which one counterparty agrees to either pay or receive from the other cash flows based on changes in the value of either an equity or commodity index, a basket of stocks or commodities, or a single stock or commodity.

Interest rate swaps are agreements where two counterparties exchange a series of payments based on different interest rates applied to a notional amount. With the Dodd-Frank regulations, certain interest rate swaps traded with U.S. counterparties in the OTC market are now centrally cleared at regulated clearing houses.

Currency swaps involve the exchange of fixed payments in one currency for the receipt of fixed payments in another currency.

Forwards and futures

Futures are standardized contracts traded on regulated future exchanges, whereas forward contracts are negotiated agreements that are transacted between counterparties in the OTC market. Examples of futures and forwards are described below:

Equity and commodity futures are contractual obligations to either buy or sell at a fixed value (the contracted price) of an equity or commodity index, a basket of stocks, a single stock or commodities at a predetermined future date.

Interest rate futures are contractual obligations to either buy or sell an interest rate-sensitive financial instrument on a predetermined future date at a specified price.

Currency forwards and futures are contractual obligations to exchange one currency for another at a specified price or settlement at a predetermined future date.

Options

Options may be either acquired in standardized amounts on regulated exchanges or customized and acquired in the OTC market. They are contractual agreements under which the seller (writer) grants the purchaser the right, but not the obligation, either to buy (call option) or sell (put option) a security, exchange rate, interest rate, or other financial instrument or commodity at a predetermined price, at or by a specified future date. The seller (writer) of an option can also settle the contract by paying the cash settlement value of the purchaser's right. The seller (writer) receives a premium from the purchaser for this right. The various option agreements that the Plan enters into include equity and commodity options, interest rate options, and foreign currency options.

Credit derivatives

Credit derivatives are OTC contracts that transfer credit risk related to an underlying financial instrument (referenced asset) from one counterparty to another. Examples of credit derivatives include credit default swaps, total return swaps, and loan participations.

Credit default swaps provide protection against the decline in value of the referenced asset as a result of specified events such as payment default or insolvency. These swaps are similar in structure to an option whereby the purchaser pays a premium to the seller of the credit default swap in return for payment related to the deterioration in the value of the referenced asset. The referenced asset for credit default swaps is a debt instrument. With the Dodd-Frank regulations, certain credit default swaps traded with U.S. counterparties in the OTC market are now centrally cleared at regulated clearing houses.

Total return swaps are contracts in which one counterparty agrees to pay or receive from the other cash flows based on changes in the value of the referenced asset.

Other derivative products

The Plan also transacts in other derivative products including statistic swaps and dividend swaps in the OTC market. An investor may trade the statistic swaps with the objective of adding value or hedging for risks associated with the magnitude of movement, i.e., volatility, variance, correlation, covariance of some underlying products, such as exchange rates, or stock indexes. Dividend swaps are OTC contracts where an investor agrees to match all dividends paid out by an underlying stock or index over a specified time period. In return, the dividend payer receives a fixed amount at expiry called the dividend swap rate.

The following schedule summarizes the notional amounts and fair value of the Plan's derivative contracts held as at December 31:

			2014		2013
(Canadian $ millions)		**Notional**	**Fair Value**	Notional	Fair Value
Equity and commodity derivatives					
Swaps		**$ 34,656**	**$ (2,558)**	$ 23,038	$ 160
Futures		**5,438**	**61**	6,798	(40)
Options: Listed	– purchased	**57**	**4**	106	32
	– written	**32**	**(5)**	159	(3)
OTC	– purchased	**4,525**	**91**	2,821	66
	– written	**3,864**	**(164)**	3,953	(104)
		48,572	**(2,571)**	36,875	111
Interest rate derivatives					
Swaps		**50,716**	**61**	22,110	21
Futures		**176,507**	**6**	216,554	(13)
Options: Listed	– purchased	**3,532**	**2**	1,458	1
	– written	**1,823**	**–**	1,450	–
OTC	– purchased	**6,188**	**43**	8,932	100
	– written	**17,061**	**(33)**	16,961	(95)
		255,827	**79**	267,465	14
Currency derivatives					
Swaps		**7,199**	**29**	4,751	1
Forwards[9]		**48,298**	**180**	47,044	(118)
Futures		**27**	**–**	126	–
Options: OTC	– purchased	**7,431**	**106**	7,402	85
	– written	**6,539**	**(92)**	6,306	(56)
		69,494	**223**	65,629	(88)
Credit derivatives					
Credit default swaps	– purchased	**12,414**	**(634)**	9,294	(193)
	– written	**9,263**	**434**	7,259	52
Total return swaps		**32**	**2**	48	3
		21,709	**(198)**	16,601	(138)
Other derivatives					
Statistic swaps		**4,571**	**(48)**	3,746	(32)
Dividend swaps		**332**	**(11)**	361	(11)
		4,903	**(59)**	4,107	(43)
		400,505	**(2,526)**	390,677	(144)
Net cash collateral (received)/paid under derivative contracts		**–**	**(50)**	–	125
Notional and net fair value of derivative contracts		**$ 400,505**	**$ (2,576)**	$ 390,677	$ (19)

[9] Excludes currency forwards related to Real Estate assets as disclosed in note 5.

The net fair value of derivative contracts as at December 31 in the previous table is represented by:

(Canadian $ millions)	2014	2013
Derivative-related receivables	$ 1,624	$ 1,494
Cash collateral paid under derivative contracts	–	139
Derivative-related liabilities	(4,150)	(1,638)
Cash collateral received under derivative contracts	(50)	(14)
	$ (2,576)	$ (19)

(d) Investment asset mix

Direct investments, derivative contracts, and investment-related receivables and liabilities are classified by asset-mix category based on the intent of the investment strategies of the underlying portfolios of the Plan. The Plan's net investments are summarized in Canadian dollars below as at December 31:

	2014		2013	
	Effective Net Investments at Fair Value ($ millions)	**Asset Mix %**	Effective Net Investments at Fair Value ($ millions)	Asset Mix %
Equity				
Canadian	**$ 10,707**	**7%**	$ 10,863	8%
Non-Canadian	**58,140**	**38**	51,034	37
	68,847	**45**	61,897	45
Fixed income				
Bonds	**35,188**	**23**	30,529	22
Real-rate products	**30,364**	**20**	26,368	19
	65,552	**43**	56,897	41
Natural resources				
Commodities	**9,032**	**6**	8,215	6
Timberland	**2,592**	**2**	2,446	2
Sector investment[10]	**275**	**–**	166	–
	11,899	**8**	10,827	8
Real assets				
Real estate (note 5)	**22,088**	**15**	19,239	14
Infrastructure	**12,659**	**8**	11,684	8
	34,747	**23**	30,923	22
Absolute return strategies				
Internal absolute return strategies	**7,976**	**5**	6,009	4
Alternative investments	**7,859**	**5**	6,195	4
	15,835	**10**	12,204	8
Money market	**(44,494)**	**(29)**	(33,845)	(24)
Net investments	**$ 152,386**	**100%**	$ 138,903	100%

[10] Sector investment includes oil, gas and agricultural assets.

(e) Risk management

Objectives

The Plan's primary long-term risk is that the Plan's assets will fall short of its liabilities (i.e., benefits owed to members). Therefore, the objective of investment risk management is to achieve a diversifying of risks and returns in a fashion that minimizes the likelihood of an overall reduction in total fund value and maximizes the opportunity for gains over the entire portfolio. This is achieved through asset diversification so that the market and credit exposure to any single issuer and to any single component of the capital markets is reduced to an acceptable level.

The Plan also manages its liquidity risk so that there is sufficient liquidity to enable the Plan to meet all of its future obligations as they become payable, which includes meeting short-term marked-to-market payments resulting from the Plan's derivative exposure and to give the Plan the ability to adjust the asset mix in response to the changes in the market conditions.

Policies

To apply risk management to investments in a consistent manner, the Plan has a number of policies, for example:

- Statement of Investment Policies and Procedures – The statement, posted on the Plan's website, addresses the manner in which the fund shall be invested. The statement is subject to the Board's review at least annually; the last review date was November 27, 2014. No significant changes were made to the statement at that time. The long-term rate of return goal is set at the actuarial assumed discount rate contained in the funding valuation using the going-concern basis. The Plan's investments are selected and held in accordance with the criteria and limitations set forth in the statement and in accordance with all relevant legislation. The statement includes a long-term asset-mix policy:

Exposure	Minimum	Goal	Maximum
Equities	39%	44%	49%
Fixed income	35%	48%	56%
Natural resources	3%	8%	13%
Real assets	18%	23%	28%
Money market[11]	(26)%	(23)%	(15)%
		100%	

[11] The money market asset class provides funding for investments in other asset classes.

- Board Investment Policy – This policy applies to the total-fund and aggregate asset classes. The policy addresses the risks that are relevant and material at the total-fund level. The policy specifies asset mix and risk budget allocation and lists investment constraints such as maximum exposures permitted for a single issuer, liquidity requirements, and currency management. The Board approves this policy and reviews it regularly.
- Investment Division Policy – This policy addresses the manner in which the Investment Division is organized for the purpose of undertaking the investment and risk management of the fund and for day-to-day operations management. This policy specifies the oversight role and activities of the senior committees within the Investment Division.
- Portfolio policies for each investment department – These policies are developed to apply to the individual portfolios within each asset class managed by the Investment Division. Portfolio policies include the departments' investment strategies, operating procedures, trading limits and approval requirements, risk factors and a description of how the risks will be managed and reporting requirements for each portfolio manager, particularly relating to reporting deviations from the approved portfolio policy. All portfolio policies are reviewed annually and approved by the Executive Vice-President of the Investment Division and the Senior Vice-President responsible for the department.
- Trade Authorization and Execution Operation Policy – This policy provides guidance on trading with authorized counterparties.
- Investment Division Counterparty Credit Policy – This policy applies to investments with credit risk exposure that arises from entering into certain counterparty agreements. The policy provides constraints on counterparty credit exposure and procedures for obtaining authorization to trade with a new counterparty.
- Pre-Investment Approval Policy – This policy formalizes the procedures to ensure the data needed for trade capture, pricing, risk management, and accounting is accurate, complete, and can be entered into the Plan's systems of record on a timely basis prior to commencement of trading.

Processes

The Plan uses risk budgeting to allocate risk across the investment asset classes. The risk budget is presented to the Board annually for review and approval. Each investment department is responsible for managing the investment risks associated with the investments they manage within the risk budget allocated to them. Each department is subject to compliance with the Statement of Investment Policies and Procedures, the Board Investment Policy (which includes the risk budget allocated to them), Investment Division Policy, Trade Authorization and Execution Operation Policy, Pre-Investment Approval Policy and the applicable portfolio policies. In addition, the Fixed Income department is responsible for maintaining the liquidity positions in accordance with the Plan's policies on liquidity. The Finance Division independently measures the investment risk exposure and the liquidity position of the Plan and provides the information to the Investment Division and the Investment Committee of the Board.

Each investment department has an investment committee, or an equivalent, which meets regularly to assess the investment risks associated with the portfolios it manages and determines action plans, if required. Individual managers in each investment department receive limited authority to invest from the Board by sub-delegation from senior management. Trading limits and approval requirements are set out in the portfolio policies for the department. For investments not traded on exchanges, such as alternative investments and private equity investments, the investment departments conduct due diligence before acquisition and use it as a tool to monitor the investments after acquisition. The objective is to obtain as much transparency as possible for the departments to assess the risk exposure arising from these private and alternative investments.

The senior representatives from each investment department form the Investment Risk Committee (IRC), which focuses on managing investment risks at a total-fund level. The Chief Financial Officer attends all meetings of the committee as an observer. This committee brings together the experience, investment and operational business judgment required for assessing and managing market, credit and liquidity risks on a regular basis. It monitors the currency positions, interest rate risk and liquidity risk at the total-fund level. The committee meets every other week, or more frequently as required. Reporting to the IRC are the Investment Division Counterparty Credit Committee, the Investment Division Liquidity Committee, the Emerging Markets Committee, and the Responsible Investment Committee.

The Enterprise Risk Management Committee oversees investment and non-investment risks faced by the Plan. The committee is chaired by the Chief Executive Officer and includes senior representatives from all divisions. The Enterprise Risk Management Committee meets regularly and reports to the Board semi-annually and more frequently as necessary.

(f) Credit risk

The Plan is exposed to the risk that a counterparty defaults or becomes insolvent. Credit risk is the risk of loss associated with a counterparty's inability to fulfill its payment obligations. Credit risk may arise directly from an obligor, an issuer of securities, or indirectly from a guarantor of a credit obligation.

Credit risk management

The Plan actively manages its credit exposures. When over exposures are detected – either in individual exposures or in groups of exposures – the Plan takes action to mitigate the risks. Such actions may include reducing the exposures and using credit derivatives.

Except for debt issued or guaranteed without significant conditions by the Government of Canada, by the government of a province or territory of Canada (with an investment grade credit rating), or by the Government of the United States of America, the Plan's total investment in securities of a single issuer across all asset classes shall not exceed 3% of the market value of the total fund without the approval of the Board. Debt exposure to a single issuer or with a single guarantor shall not exceed 2% of the market value of the Plan without approval of the Board. Further, not more than 10% of the market value of the Plan may be made up of non–investment grade or unrated investments.

The Plan enters into agreements with counterparties to limit its exposure to credit losses. An International Swaps and Derivatives Association (ISDA) Master Agreement is executed with most OTC derivative counterparties, which allows both parties to settle obligations on a net basis when termination or other predetermined events occur. The Plan also negotiates collateral agreements known as credit support annexes (CSAs) with key counterparties to further mitigate counterparty credit risk. A CSA gives the Plan the power to realize collateral posted by counterparties in the event of a default by such counterparties.

Since collateral is an important mitigant of counterparty credit risk, the Plan routinely obtains collateral from its counterparties, not only under OTC derivative contracts but also under reverse repurchase agreements. Note 2i provides further details on securities collateral.

The Plan has a credit risk assessment process to approve prospective new counterparties and to monitor authorized counterparties for derivative contracts, repurchase and reverse repurchase agreements, securities borrowing agreements, prime broker relationships and futures and options clearing. The Plan deals primarily with counterparties that have an investment grade credit rating. Policies are in place to limit the maximum exposures to any individual counterparty for derivative contracts or repurchase and reverse repurchase agreements, prime broker relationships and futures and options clearing.

Maximum exposure to credit risk before collateral held

The Plan assumes credit risk exposure through debt investments and amounts receivable from the Province of Ontario and brokers. The maximum exposure to credit risk related to these financial instruments is their fair value as presented in the consolidated statements of financial position and note 2a. The Plan is also exposed to credit risk of counterparties to its OTC derivative transactions. Counterparty credit risk exposure for OTC derivatives is measured as the net positive fair value of the contractual obligations with the counterparties.

To monitor credit risk, the Plan produces, on a quarterly basis, a concentration report by credit rating of all credit sensitive financial securities.

Counterparties are assigned a credit rating as determined by the Plan's internal credit risk management function. Counterparty credit ratings are also compared to their external ratings as provided by recognized credit rating agencies on a daily basis.

The credit risk exposure of debt investments and OTC derivatives, by credit rating category, without taking account of any collateral held or other credit enhancements as at December 31 is as follows:

2014

Credit rating (Canadian $ millions)	**Bonds and Short-Term Investments**	**Real-Rate Products**	**Securities Purchased under Agreements to Resell**	**Loans and Private Debt**	**OTC Derivatives**
AAA/R-1 (high)	$ 30,581	$ 16,594	$ –	$ –	$ –
AA/R-1 (mid)	13,749	10,356	3,291	–	15
A/R-1 (low)	4,549	2,918	14,903	–	275
BBB/R-2	2,364	12	464	–	–
Below BBB/R-2	2,361	–	–	–	–
Unrated[12, 13]	3,141	244	5,478	5,605	–
Total	**$ 56,745**	**$ 30,124**	**$ 24,136**	**$ 5,605**	**$ 290**

2013

Credit rating (Canadian $ millions)	Bonds and Short-Term Investments	Real-Rate Products	Securities Purchased under Agreements to Resell	Loans and Private Debt	OTC Derivatives
AAA/R-1 (high)	$ 32,509	$ 14,876	$ –	$ –	$ –
AA/R-1 (mid)	8,055	9,295	2,785	–	31
A/R-1 (low)	2,246	2,653	11,261	–	215
BBB/R-2	1,104	16	–	–	–
Below BBB/R-2	1,348	–	–	–	–
Unrated[12, 13]	1,895	243	7,805	4,955	–
Total	$ 47,157	$ 27,083	$ 21,851	$ 4,955	$ 246

[12] Unrated comprises securities that are either privately held, managed externally, or not rated by the rating agencies.

[13] Beginning on January 1, 2014, fund investments have been classified based on the type of fund and valuation methodology. 2013 comparative figures have been reclassified to reflect the change.

The Plan is also exposed to credit risk through off-balance sheet arrangements. For off-balance sheet guarantees, the maximum exposure to credit risk is the maximum amount that the Plan would have to pay if the guarantees were to be called upon. For loan commitments, the maximum exposure is the committed amount under the agreements. For credit derivatives, the maximum exposure is the notional amount of written credit derivatives as presented in note 2c.

As at December 31 (Canadian $ millions)		**2014**		2013
Guarantees	**$**	**394**	$	424
Loan commitments		**139**		169
Notional amount of written credit derivatives		**9,263**		7,259
Total off-balance sheet credit risk exposure	**$**	**9,796**	$	7,852

While the Plan's maximum exposure to credit risk is the carrying value of the assets, or, in the case of off-balance sheet items, the amount guaranteed or committed, in most cases the likely exposure is far less due to collateral, credit enhancements (e.g., guarantees in favour of the Plan) and other actions taken to mitigate the Plan's exposure, as described previously.

Credit risk concentrations

As at December 31, 2014, the Plan has a significant concentration of credit risk with the Government of Canada, the Province of Ontario and the U.S. Treasury. This concentration relates primarily to holding Government of Canada issued securities of $43.3 billion (2013 – $43.8 billion), U.S. Treasury issued securities of $2.8 billion (2013 – $0.8 billion), Province of Ontario bonds of $6.2 billion (2013 – $4.6 billion), receivable from the Province of Ontario (see note 3) of $3.1 billion (2013 – $3.0 billion) and future provincial funding requirements of the Plan.

(g) Market risk

Market risk is the risk of loss that results from fluctuations in equity and commodity prices, interest and foreign exchange rates, and credit spreads. The Plan is exposed to market risk from its investing activities. The level of market risk to which the Plan is exposed varies depending on market conditions, expectations of future price movements, the occurrence of certain catastrophic events (e.g., hurricanes and earthquakes) affecting the prices of insurance linked securities, expectations of future yield movements and the composition of the asset mix.

Market risk management

The Plan manages market risk primarily through diversifying the investments across industry sectors, investment strategies and on a global basis. A variety of derivative contracts are also utilized to manage the Plan's market risk exposures.

Market and credit risk measurement

The Plan uses a statistical Value-at-Risk (VaR)-type approach, the expected tail loss (ETL) methodology, to measure investment risk comprising of market and credit risk over a one-year horizon at a 99% confidence level. The ETL methodology captures more of the effect of extreme loss events than VaR for the same confidence level as it is the average of all the losses in the tail.

Total Asset Risk is prepared using the ETL methodology. This risk captures the investment risk exposure by asset class, reflecting the risk of potential losses in net assets due to both market and credit risk factors. Statistically, the Plan would expect to see losses in excess of the risk exposure on the report only 1% of the time over a one-year period, subject to certain assumptions and limitations discussed below.

The ETL methodology is a statistical approach that accounts for market volatility and credit risk as well as risk diversification achieved by investing in various products and markets. Risks are measured consistently across all markets and products and can be aggregated to arrive at a single risk number. The one-year 99% ETL number used by the Plan is generated using a historical simulation and bootstrap sampling approach that reflects the expected annual return on the portfolio in the worst 1% of the cases. The Plan currently uses the previous 28 years of market data. When sufficient historical data is not available, proxies and statistical methods are used to complete the data series.

There are limitations to the ETL methodology in use. For example, historical data may not provide the best estimate of future changes. It may fail to capture the correlation in asset returns in extreme adverse market movements which have not occurred in the historical window. The bootstrap sampling approach and long historical window, however, mitigate this limitation to some extent by enabling the generation of a set of scenarios that include extreme adverse events. Another limitation is that the Plan computes the risk relative to asset positions at the close of the business day. Positions may change substantially during the course of a trading day. These limitations and the nature of the ETL measure mean that the Plan's losses may exceed the risk exposure amounts indicated in any risk reports.

The Plan continuously monitors and enhances the risk calculation methodology, striving for better estimation of risk exposure. A number of initiatives were completed in the past year that significantly improved the accuracy of calculated risk measures. Existing risk methodologies were modified to incorporate more accurate risk models and more reliable risk data.

The table below shows the year over year change in Total Asset Risk ETL of the Plan as at December 31.

(Canadian $ billions)[14]	**2014**	2013
Equity		
Canadian	**$ 4.0**	$ 4.0
Non-Canadian	**18.5**	16.5
Fixed income		
Bonds	**1.5**	2.5
Real-rate products	**5.5**	4.5
Natural resources		
Commodities	**4.0**	5.0
Timberland	**0.5**	0.5
Real assets		
Real estate	**1.5**	1.0
Infrastructure	**2.0**	2.0
Absolute return strategies	**2.5**	1.5
Money market	**5.5**	4.5
Total Asset Risk ETL Exposure[15]	**$ 28.0**	$ 26.0

[14] Rounded to the nearest $0.5 billion.

[15] Total Asset Risk ETL Exposure does not equal the sum of ETL exposure for each asset class because diversification reduces total risk exposure.

Interest rate risk

Interest rate risk refers to the effect on the market value of the Plan's assets and liabilities due to fluctuations in interest rates. The value of the Plan's assets is affected by short-term changes in nominal and real interest rates. Pension liabilities are exposed to fluctuations in long-term interest rates as well as expectations for salary escalation.

The Plan manages the interest rate risk by using interest rate derivatives as detailed in note 2c to the consolidated financial statements. After giving effect to the derivative contracts and investment-related receivables and liabilities discussed in note 2c, a 1% increase in nominal interest rates would result in a decline in the value of the Plan's investments in fixed income securities of 7% or $2.4 billion (2013 – 6% or $1.9 billion). Similarly, a 1% increase in real interest rates would result in a decline in the value of the Plan's investments in real-rate products of 17% or $5.2 billion (2013 – 14% or $3.8 billion).

As at December 31, 2014, holding the inflation and salary escalation assumptions constant, a 1% decrease in the assumed long-term real rates of return would result in an increase in the pension liabilities of approximately 21% or $36.0 billion (2013 – 19% or $28.9 billion).

Foreign currency risk

Foreign currency exposure arises from the Plan's holdings of foreign currency-denominated investments and related derivative contracts.

As at December 31, the Plan had investments exposed to foreign currency. In Canadian dollars this exposure is as follows:

(Canadian $ millions)	**2014**	2013
Currency	**Net Exposure**	Net Exposure
United States Dollar	**$ 44,383**	$ 27,796
British Pound Sterling	**8,137**	7,587
Euro	**6,179**	6,977
Chinese Renminbi	**3,426**	2,701
Chilean Peso	**2,794**	2,517
Brazilian Real	**2,207**	2,266
Japanese Yen	**1,764**	2,331
South Korean Won	**1,704**	1,815
Danish Krona	**1,668**	1,640
Australian Dollar	**1,496**	1,540
Indian Rupee	**1,176**	776
Other	**6,285**	6,735
	$ 81,219	$ 64,681

As at December 31, with all other variables and underlying values held constant, a 5% increase/decrease in the value of the Canadian dollar against major foreign currencies would result in an approximate decrease/increase in the value of net investments as follows:

(Canadian $ millions)	**2014**	2013
Currency	**Change in Net Investment Value**	Change in Net Investment Value
United States Dollar	**$ 2,219**	$ 1,390
British Pound Sterling	**407**	379
Euro	**309**	349
Chinese Renminbi	**171**	135
Other	**955**	981
	$ 4,061	$ 3,234

(h) Liquidity risk

Liquidity risk refers to the risk that the Plan does not have sufficient cash to meet its current payment liabilities and acquire investments in a timely and cost-effective manner. Liquidity risk is inherent in the Plan's operations and can be impacted by a range of situation specific and market-wide events including, but not limited to, credit events and significant movements in the market.

Liquidity risk management

The liquidity position of the Plan is analyzed daily to ensure the Plan maintains at least 1.25% of its assets in unencumbered Canadian treasury bills. The Plan also manages its liquidity by holding additional unencumbered Government of Canada securities (bonds, treasury bills and real-rate bonds) and U.S. government securities that are available for repurchase agreements so that the Plan is able to withstand the liquidity effects of a market stress event and pay its contractual cash flows and projected cash requirements over a one-year horizon with a 99% probability. The Plan's liquidity position is periodically tested by simulations of major events such as significant movements in the market.

Liquid assets

The Plan maintains a portfolio of highly marketable assets including Canadian and U.S. government bonds that can be sold or funded on a secured basis as protection against any unforeseen interruption to cash flow. The fair value of the Canadian and U.S. government bonds is $46,080 million as at December 31, 2014 (2013 – $44,544 million). The Plan also has a net position of publicly traded equities of $34,273 million (2013 – $32,914 million) which are listed on major recognized stock exchanges. These securities are readily realizable and convertible to cash.

Contractual maturity

The Plan's liabilities include accrued pension benefits, investment-related liabilities, due to brokers, accounts payable and accrued liabilities. Due to brokers, accounts payable and accrued liabilities are all due within one year. As the Plan may settle securities sold but not yet purchased, cash collateral received under credit support annexes and derivatives at fair value before contractual maturity, they are considered to mature within one year.

The Plan's investment-related liabilities by maturity as at December 31 are as follows:

(Canadian $ millions)				**2014**
	Within One Year	One to Five Years	Over Five Years	**Total**
Securities sold under agreements to repurchase	$ (39,783)	$ (5,477)	$ –	**$ (45,260)**
Securities sold but not yet purchased				
Fixed income	(16,522)	–	–	**(16,522)**
Equities	(2,291)	–	–	**(2,291)**
Real estate	(728)	(2,408)	(1,371)	**(4,507)**
Cash collateral received under credit support annexes	(57)	–	–	**(57)**
Derivative-related, net	(4,149)	–	–	**(4,149)**
Total	$ (63,530)	$ (7,885)	$ (1,371)	**$ (72,786)**

(Canadian $ millions)				2013
	Within One Year	One to Five Years	Over Five Years	Total
Securities sold under agreements to repurchase	$ (35,873)	$ (2,002)	$ –	$ (37,875)
Securities sold but not yet purchased				
Fixed income	(13,861)	–	–	(13,861)
Equities	(1,269)	–	–	(1,269)
Real estate	(722)	(2,289)	(1,322)	(4,333)
Cash collateral received under credit support annexes	(317)	–	–	(317)
Derivative-related, net	(1,551)	–	–	(1,551)
Total	$ (53,593)	$ (4,291)	$ (1,322)	$ (59,206)

(i) Securities collateral

The Plan pledges and receives cash and security collateral in the ordinary course of managing net investments. Security collateral consists primarily of Canadian and U.S. government securities. Generally, additional collateral is provided if the value of the securities falls below a predetermined level. The securities transferred are recognized as assets when the Plan retains substantially all risks and rewards, including credit risk, settlement risk and market risk. The Plan is not allowed to either pledge the same securities with other financial institutions or to sell them to another entity unless the Plan substitutes such securities with other eligible securities.

As at December 31, 2014, securities transferred as collateral for securities sold under agreements to repurchase amount to $46,662 million (2013 – $37,635 million) with an associated liability of $45,260 million (2013 – $37,875 million). Securities transferred as collateral or margin for derivative-related liabilities amount to $3,322 million (2013 – $900 million) with an associated liability is $4,150 million (2013 – $1,638 million). Security collateral for securities sold but not yet purchased amounts to $322 million (2013 – $194 million), which, together with related cash collateral, has an associated liability of $2,291 million (2013 – $1,269 million).

Canadian and U.S. government securities with a fair value of $25,924 million (2013 – $22,301 million) have been received from various financial institutions as collateral. The collateral is not recognized as the Plan's asset since the risks and rewards of the ownership remain with the counterparties. The Plan holds the collateral received as long as the Plan is not a defaulting party or an affected party in connection with a specified condition listed on the contractual agreements and there is no early termination of the contractual agreement. The Plan is permitted to either sell or repledge the collateral in the absence of default by the owner of the collateral, but it has neither sold nor repledged any collateral as of December 31, 2014, and 2013.

(j) Securities borrowing

The Plan does not recognize any securities borrowed as its investment assets because the risks and rewards of the borrowed securities remain with the lenders. The security collateral posted by the Plan, related to the securities borrowed, continues to be recognized as the Plan's assets because the Plan retains all associated risks and rewards. As at December 31, 2014, securities with a fair value of $589 million (2013 – $10 million) were borrowed and collateral with a fair value of $617 million (2013 – $11 million) were posted by the Plan.

NOTE 3.
RECEIVABLE FROM THE PROVINCE OF ONTARIO

The receivable from the Province consists of required matching contributions and interest thereon.

As at December 31 (Canadian $ millions)	2014	2013
Contributions receivable	**$ 3,047**	$ 2,914
Accrued interest receivable	**51**	51
	$ 3,098	$ 2,965

The receivable as at December 31, 2014, from the Province of Ontario consists of $1,526 million, which was received in January 2015, and an estimated $1,572 million to be received with interest in January 2016. The receivable as at December 31, 2013, from the Province consisted of $1,461 million, which was received in January 2014, and an initial estimate of $1,504 million to be received in January 2015. The difference between the initial estimates and the actual amount received was due to interest.

NOTE 4.
ACCRUED PENSION BENEFITS

(a) Actuarial assumptions

The actuarial assumptions used in determining the value of accrued pension benefits of $172,725 million (2013 – $148,571 million) reflect management's best estimate of future economic events and involve both economic and non-economic assumptions. The non-economic assumptions include considerations such as mortality as well as withdrawal and retirement rates. The primary economic assumptions include the discount rate, the salary escalation rate and the inflation rate. The discount rate is based on market rates, as at the valuation date, of bonds issued by the Province of Ontario, which have characteristics similar to the Plan's liabilities. In 2014, the discount rate was determined by applying a weighted average discount rate that reflects the estimated timing and amount of benefit payments. In 2013, the discount rate was determined by identifying the rate on long-term Government of Canada bonds plus a spread of the Province of Ontario. This change in accounting estimate is applied prospectively beginning January 1, 2014, decreasing the accrued pension benefits by $1,564 million as at December 31, 2014. The inflation rate is the difference between the yield on Government of Canada long-term nominal bonds and Government of Canada real-return bonds. The salary escalation rate incorporates the inflation rate assumption and long-term expectation of growth in real wages.

A summary of the primary economic assumptions is as follows:

As at December 31	2014	2013
Discount rate	**3.35%**	4.20%
Salary escalation rate	**2.70%**	3.00%
Inflation rate	**1.70%**	2.00%
Real rate	**1.65%**	2.20%

The primary economic assumptions were changed as a result of changes in capital markets during 2014. These changes in economic assumptions resulted in a net increase in the value of accrued pension benefits of $18,244 million (2013 – $21,973 million decrease inclusive of the impact of a 2% salary adjustment pursuant to the Elementary Teachers' Federation of Ontario salary agreement reached in 2013).

The non-economic assumptions were updated in 2014 to reflect recent experience of Plan members related to mortality rates and expected rates of improvement in future mortality. Changes in non-economic assumptions increased the accrued pension benefits by $1,584 million. No changes to the non-economic assumptions were adopted in 2013. The changes in economic and non-economic assumptions, including the change in estimate for determining the discount rate resulted in a net increase in the value of accrued pension benefits of $18,264 million (2013 – $21,973 million decrease).

(b) Plan provisions

Credited service earned after December 31, 2009, is subject to conditional inflation protection as described in paragraph (f) of the Description of Plan note. The inflation protection benefits vary between 50% and 100% of the change in the Consumer Price Index (CPI) for credited service earned between January 1, 2010, and December 31, 2013, and vary between 0% and 100% of the change in the CPI for credited service earned after 2013. The conditional inflation protection provision can only be invoked or updated when a funding valuation is filed. The Ontario government and designated employers participating in the Plan will make extra contributions to the Plan to match the inflation protection benefits members forgo up to a maximum forgone inflation of 50% of CPI.

For the financial statement valuation, future pension payments for the credited service earned are indexed at the levels stated in the most recent funding valuation filing. The indexation levels from the most recent filing as at January 1, 2014, are as follows:

Credited Service	Inflation Protection Level
Earned before 2010	100% of CPI
Earned during 2010–2013	60% of CPI
Earned after 2013	60% of CPI

In the most recent filing, inflation protection was partially restored for recent retirees. Effective January 1, 2015, pensioners who retired after 2009 received a one-time increase to their pensions to prospectively restore benefits to the level they would have been had 100% inflation protection been provided each year since retirement commenced. Future cost-of-living increases will be equal to 60% of the annual increase in the CPI on credited service earned after 2009 (up from the previous level of 50%). This level will remain in effect until the next actuarial valuation is filed with the regulatory authorities, at which time the level may be reduced or increased depending on the funded status of the Plan.

(c) Experience gains and losses

Experience losses on the accrued pension benefits of $139 million (2013 – $949 million gains) arose from differences between the actuarial assumptions and actual results.

NOTE 5.
INVESTMENT IN REAL ESTATE

The Plan's real estate portfolio is comprised of real estate-related investments that are either owned or managed on behalf of the Plan by The Cadillac Fairview Corporation Limited (CFCL), a wholly owned subsidiary. The Plan consolidates the fair value of the assets and liabilities of CFCL and the investment holding companies managed by CFCL. Investment holding companies and investment entities, including the joint ventures, managed by external parties, are recognized as the Plan's investments measured at fair value and presented on a non-consolidated basis.

The Plan guarantees three debentures issued by a real estate trust it consolidates. No payments have been made by the Plan into the real estate trust or related to the three debentures. The debentures are comprised of $1.25 billion 3.24% Series A Debentures maturing on January 25, 2016, $0.75 billion 4.31% Series B Debentures maturing on January 25, 2021, and $0.6 billion 3.64% Series C Debentures maturing on May 9, 2018. The debentures, included in the Plan's real estate investment-related liabilities, may be redeemed by the issuer at any time prior to maturity.

The tables below provide information on the real estate portfolio. Intercompany transactions and balances are eliminated upon consolidation. The first table presents major components of the net investment in real estate. The second table presents major components of net real estate income:

As at December 31	2014		2013	
(Canadian $ millions)	**Fair Value**	**Cost**	Fair Value	Cost
Assets[1, 2]				
Real estate properties	**$ 23,157**	**$ 14,371**	$ 20,860	$ 13,013
Investments	**3,218**	**2,301**	2,534	1,283
Other assets	**220**	**198**	178	165
Total assets	**26,595**	**16,870**	23,572	14,461
Liabilities[1, 2]				
Long-term debt	**3,623**	**3,418**	3,626	3,454
Other liabilities	**884**	**729**	707	575
Total liabilities	**4,507**	**4,147**	4,333	4,029
Net investment in real estate	**$ 22,088**	**$ 12,723**	$ 19,239	$ 10,432

[1] U.S. Dollar, British Pound Sterling and Colombian Pesos net assets have been hedged by way of foreign currency forward contracts for a notional amount of $1,476 million (2013 – $1,286 million) with a combined fair value of ($11) million (2013 – ($30) million).

[2] Joint ventures managed by external parties hold real estate properties and have liabilities. The net asset value of these joint ventures is included in investments, representing assets of $566 million (2013 – $2,116 million) and liabilities of $305 million (2013 – $970 million).

(Canadian $ millions)	**2014**	2013
Revenue		
Rental	**$ 1,796**	$ 1,700
Investment and other	**94**	78
	1,890	1,778
Expenses		
Property operating	**776**	724
General and administrative	**48**	35
Other	**29**	21
	853	780
Operating income	**1,037**	998
Interest expense	**(128)**	(139)
Income (note 6)	**909**	859
Net investment gain	**1,293**	1,394
Net real estate income	**$ 2,202**	$ 2,253

NOTE 6.
NET INVESTMENT INCOME

Net investment income/(loss) after allocating net realized and unrealized gains on investments, management fees and transaction costs to asset classes

Net investment income is reported net of management fees, transaction costs, and is grouped by asset class. Net investment income, after giving effect to derivative contracts, for the year ended December 31, is as follows:

Net Investment Income **2014**

(Canadian $ millions)	Income[1]	Realized[2]	Unrealized[2]	Investment Income	Management Fees	Transaction Costs	Net Investment Income
Fixed income							
Bonds[3]	$ 942	$ 1,281	$ 492	$ 2,715	$ (3)	$ (4)	$ 2,708
Short-term investments[3]	–	96	1	97	–	–	97
Alternative investments[3, 4]	92	(288)	894	698	(40)	(1)	657
Canadian real-rate products	470	55	2,005	2,530	–	–	2,530
Non-Canadian real-rate products	164	343	1,585	2,092	–	–	2,092
	1,668	1,487	4,977	8,132	(43)	(5)	8,084
Equity							
Publicly traded							
Canadian	(58)	1,112	(5)	1,049	–	(4)	1,045
Non-Canadian	619	3,903	372	4,894	(60)	(57)	4,777
Non-publicly traded							
Canadian[3]	41	(11)	67	97	(7)	(30)	60
Non-Canadian[3]	553	1,149	907	2,609	(194)	(140)	2,275
	1,155	6,153	1,341	8,649	(261)	(231)	8,157
Natural resources							
Commodities	(24)	(1,395)	(2,449)	(3,868)	(1)	(3)	(3,872)
Timberland	48	(30)	525	543	(1)	(3)	539
Sector investment[5]	34	–	(13)	21	(30)	(5)	(14)
	58	(1,425)	(1,937)	(3,304)	(32)	(11)	(3,347)
Real assets							
Real estate (note 5)	937	735	558	2,230	–	(28)	2,202
Infrastructure	524	322	354	1,200	(8)	(28)	1,164
	1,461	1,057	912	3,430	(8)	(56)	3,366
	$ 4,342	$ 7,272	$ 5,293	$ 16,907	$ (344)	$ (303)	$ 16,260

[1] Income includes interest, dividends, real estate operating income (net of interest expense), and other investment-related income and expenses.

[2] Includes net foreign currency losses of $74 million.

[3] Beginning in January 1, 2014, fund investments have been classified based on the type of fund and valuation methodology. 2013 comparative figures have been reclassified to reflect the change.

[4] Comprised primarily of hedge funds and managed futures accounts.

[5] Sector investment includes oil, gas and agricultural assets.

Net Investment Income 2013

(Canadian $ millions)	Income	Realized[6]	Unrealized[6]	Investment Income	Management Fees	Transaction Costs	Net Investment Income
Fixed income							
Bonds[7]	$ 827	$ (85)	$ (2,031)	$ (1,289)	$ (1)	$ (1)	$ (1,291)
Short-term investments[7]	(152)	–	3	(149)	–	–	(149)
Alternative investments[7, 8]	147	(217)	741	671	(41)	(1)	629
Canadian real-rate products	468	266	(3,523)	(2,789)	–	–	(2,789)
Non-Canadian real-rate products	163	184	(1,373)	(1,026)	–	–	(1,026)
	1,453	148	(6,183)	(4,582)	(42)	(2)	(4,626)
Equity							
Publicly traded							
Canadian	126	744	310	1,180	–	(8)	1,172
Non-Canadian	863	3,958	5,297	10,118	(85)	(121)	9,912
Non-publicly traded							
Canadian[7]	45	29	17	91	(7)	(4)	80
Non-Canadian[7]	137	554	2,700	3,391	(102)	(67)	3,222
	1,171	5,285	8,324	14,780	(194)	(200)	14,386
Natural resources							
Commodities	–	(528)	227	(301)	–	–	(301)
Timberland	50	(4)	287	333	(2)	–	331
Sector investment[9]	22	–	12	34	(10)	(1)	23
	72	(532)	526	66	(12)	(1)	53
Real assets							
Real estate (note 5)	870	591	803	2,264	–	(11)	2,253
Infrastructure	704	393	662	1,759	(9)	(98)	1,652
	1,574	984	1,465	4,023	(9)	(109)	3,905
	$ 4,270	$ 5,885	$ 4,132	$ 14,287	$ (257)	$ (312)	$ 13,718

[6] Includes net foreign currency losses of $852 million.

[7] Beginning in January 1, 2014, fund investments have been classified based on the type of fund and valuation methodology. 2013 comparative figures have been reclassified to reflect the change.

[8] Comprised primarily of hedge funds and managed futures accounts.

[9] Sector investment includes oil, gas and agricultural assets.

NOTE 7.
INVESTMENT RETURNS AND RELATED BENCHMARK RETURNS

Investment returns and related benchmark returns by investment asset class for the year ended December 31 are as follows:

	2014		2013	
(percent)	**Investment Returns**	**Investment Benchmark Returns**	Investment Returns	Investment Benchmark Returns
Fixed income	**12.0%**	**11.9%**	(7.9)%	(8.1)%
Canadian equity	**12.7**	**12.2**	12.2	13.1
Non-Canadian equity	**13.5**	**13.6**	31.3	29.9
Natural resources	**(19.4)**	**(19.8)**	4.2	4.2
Real assets	**10.8**	**6.6**	14.6	10.6
Total Plan	**11.8%**	**10.1%**	10.9%	9.3%

Investment returns have been calculated using a time-weighted rate of return methodology.

The Plan identifies benchmarks to evaluate the investment management performance. The performance of each asset class is measured against benchmarks that simulate the results based on the investment strategies employed by the investment managers identified for the asset class.

The total Plan return is measured against a Canadian dollar-denominated composite benchmark produced by aggregating returns from each of the policy asset-class benchmarks, using the Plan's asset-mix policy weights.

NOTE 8.
STATUTORY ACTUARIAL VALUATIONS

Statutory actuarial valuations are prepared periodically to determine the funding requirements of the Plan. In 2014, active members were required to contribute 11.50% (2013 – 11.15%) of the portion of their salaries covered by the CPP and 13.10% (2013 – 12.75%) of salaries above this level. Member contributions are matched by the Province and designated employers. In addition, the Funding Management Policy established by the co-sponsors provides procedures for the co-sponsors to determine contributions and benefits.

Under an agreement between the co-sponsors, contribution rates are as follows:

	Contribution Rate	
(percent)	Covered by CPP	Not Covered by CPP
2012	10.80%	12.40%
2013	11.15%	12.75%
2014	11.50%	13.10%

The actuarial methods used to prepare statutory actuarial valuations are different than those used to prepare a financial statement actuarial valuation and the amounts disclosed in these consolidated financial statements. The statutory actuarial valuations use a valuation method which takes into account future benefits to be earned and future contributions to be made by members of the Plan as at the valuation date.

The most recent statutory actuarial valuation that has been filed with regulatory authorities was prepared as at January 1, 2014, by Mercer (Canada) Limited and disclosed a funding surplus of $1,169 million, after adopting conditional inflation protection of 60% for credited service earned between 2010 and 2013 and after 2013, as well as recognizing the special contributions included in the 2014 contribution rate described above, of 1.1% of salary payable until December 31, 2026.

NOTE 9.
CONTRIBUTIONS

(Canadian $ millions)	**2014**	2013
Members		
Current service[1]	**$ 1,547**	$ 1,483
Optional credit	**31**	28
	1,578	1,511
Province of Ontario		
Current service	**1,528**	1,464
Interest	**37**	37
Optional credit	**28**	26
	1,593	1,527
Other employers	**32**	29
Transfers from other pension plans	**13**	14
	45	43
	$ 3,216	$ 3,081

[1] Contributions past due are less than $1 million in 2014 and 2013.

NOTE 10.
BENEFITS PAID

(Canadian $ millions)	2014	2013
Retirement pensions	**$ 4,883**	$ 4,744
Death benefits	**315**	311
Disability pensions	**27**	28
Commuted value transfers	**45**	41
Family law transfers	**26**	17
Transfers to other plans	**9**	8
Refunds	**1**	1
	$ 5,306	$ 5,150

NOTE 11.
ADMINISTRATIVE EXPENSES

(a) Investment expenses

(Canadian $ millions)	2014	2013
Salaries, incentives and benefits	**$ 267.3**	$ 232.1
Premises and equipment	**35.9**	37.7
Professional and consulting services	**51.3**	46.8
Information services	**21.2**	18.5
Communication and travel	**16.0**	13.2
Custodial fees	**9.8**	8.9
Statutory audit fees	**1.9**	1.6
Board and committee remuneration	**0.7**	0.7
Other	**4.7**	4.8
	$ 408.8	$ 364.3

(b) Member services expenses

(Canadian $ millions)	2014	2013
Salaries, incentives and benefits	**$ 33.2**	$ 30.0
Premises and equipment	**9.1**	8.8
Professional and consulting services	**4.8**	4.3
Communication and travel	**1.2**	1.0
Statutory audit fees	**0.1**	0.1
Board and committee remuneration	**0.1**	0.1
Other	**0.9**	0.8
	$ 49.4	$ 45.1

(c) Compensation of key management personnel

Key management personnel are defined as those persons having authority and responsibility for planning, directing and controlling the activities of the Plan, being the Board members, the executive team and the senior vice presidents of the Investment Division.

The compensation of the key management personnel is included in the administrative expenses of the Plan. There are no other related party transactions between the key management personnel and the Plan.

The compensation of the key management personnel[1] as at December 31 is summarized below:

(Canadian $ millions)	2014	2013
Short-term employee benefits	**$ 14.3**	$ 14.8
Post-employment benefits	**7.1**	0.6
Termination benefits	**–**	2.6
Other long-term benefits	**15.1**	21.4
Total	**$ 36.5**	$ 39.4

1 The table does not include compensation of either officers or directors of The Cadillac Fairview Corporation Limited.

(d) Employees' post-employment benefits

The employees of the Plan are members of the defined benefit plans, of either the Ontario Public Service Employees Union (OPSEU) Pension Plan or Public Service Pension Plan (PSPP). The expected contributions from the Plan in 2015 are approximately $11.6 million. Some employees are also members of the Public Service Supplementary Plan (PSSP). These three pension plans are sponsored by the Province of Ontario and information is available on www.optrust.com and www.opb.ca. As the employer, the Plan matches the employees' contributions to these pension plans. Some senior management employees also participate in a non-registered, unfunded Supplemental Employee Retirement Plan (SERP) managed by the Plan to provide the employees non-indexed retirement benefits equal to 2% of the employee's pensionable earnings times the number of years of service, less the initial annual pension to which the employee is entitled under the PSPP and PSSP, combined. The contributions expensed by the Plan during the year were $17.6 million (2013 – $7.9 million). Contributions are included in the salaries, incentives and benefits expenses.

NOTE 12.
CAPITAL

The funding surpluses or deficits determined regularly in the funding valuations prepared by an independent actuary are described as the Plan's capital in the consolidated financial statements. The actuary's funding valuation is used to measure the long-term health of the Plan. The actuary tests the Plan's ability to meet its obligations to all current Plan members and their survivors. Using an assumed rate of return, the actuary projects the Plan's benefits to estimate the current value of the liability (see note 4), which is compared to the sum of the Plan assets, the future contributions for all current Plan members and the present value of the contribution increases for future members. The result of the comparison is either a surplus or a deficit.

The objective of managing the Plan's capital is to ensure the Plan is fully funded to pay the plan benefits over the long term. The co-sponsors change the benefit and contribution levels to eliminate any deficits. The Funding Management Policy set by the co-sponsors in the Partners' Agreement provides guidance on how the co-sponsors manage the Plan's capital.

A funding valuation, including a plan to eliminate any deficit, is required to be filed with the pension regulator at least every three years. A preliminary funding valuation is performed by the actuary when the valuation is not filed with the regulator assisting the co-sponsors in managing the Plan's capital.

The most recent funding valuation filed is disclosed in note 8.

NOTE 13.
RETIREMENT COMPENSATION ARRANGEMENT (RCA)

Restrictions in the ITA on the payment of certain benefits from a registered plan for periods of service after 1991 may impact some Plan members. To address affected members, the RCA was established by agreement between the co-sponsors as a supplementary plan to provide these benefits.

The RCA is administered under a trust separate from the assets of the Plan. The Board has been appointed by the co-sponsors to act as the trustee of the RCA.

Because the RCA is a separate trust and the Plan does not control the RCA, the net assets available for benefits and the value of accrued benefits and deficit, referred to below, have not been included in the consolidated financial statements of the Plan.

The RCA is funded on a pay-as-you-go basis from a portion of the contributions made to the Plan by members, the Province and designated employers. The portion is based on a limit on contributions to the Plan with contributions above the limit being remitted to the RCA. The limit is determined annually by the Plan's independent actuary such that the RCA contributions are expected to be sufficient to pay the benefits over the next 12 months. At the beginning of 2015, the actuary determined that the limit should decrease from $15,900 to $15,100. Due to the funding policy adopted by the co-sponsors, the net assets available for benefits will continue to be substantially less than the accrued benefits.

In addition, because it is difficult to predict the benefits expected to be paid over the next 12 months, it is possible that the assets may be insufficient to pay the benefits. In such a case, the payment of benefits will be temporarily suspended and contributions raised in order to fund the payments that are due under the RCA.

The RCA financial statements are in compliance with Section 4600 and IFRS. A summary of the financial statements for the RCA is as follows:

As at December 31 (Canadian $ thousands)	**2014**	2013
Statements of financial position		
NET ASSETS AVAILABLE FOR BENEFITS		
Assets	**$ 29,289**	$ 27,948
Liabilities	**(3,187)**	(3,583)
	$ 26,102	$ 24,365
ACCRUED BENEFITS AND DEFICIT		
Accrued benefits	**$ 329,994**	$ 344,356
Deficit	**(303,892)**	(319,991)
	$ 26,102	$ 24,365
Statements of changes in net assets available for benefits		
Contributions	**$ 10,843**	$ 13,807
Investment income	**56**	70
	10,899	13,877
Benefits paid	**9,035**	6,591
Expenses	**127**	89
	9,162	6,680
Increase in net assets	**$ 1,737**	$ 7,197

The actuarial assumptions and the accrual of conditional inflation protection used in determining the value of accrued benefits are consistent with the Plan except that the assumed discount rate has been adjusted to reflect the effect of the 50% refundable tax under the RCA.

The estimate of the value of accrued benefits is highly sensitive to salary increases, both actual and assumed. Any changes to the salary assumptions will have a significant effect on the liabilities for future benefits. In addition, significant uncertainty exists in projecting the liabilities of the RCA due to changes in the number of future participants as well as changes to the income tax regulations relating to pensions.

NOTE 14.
COMMITMENTS

The Plan has committed to enter into investment and other transactions, which may be funded over the next several years in accordance with the terms and conditions agreed to. As at December 31, 2014, these commitments totalled $11,494 million (2013 – $8,151 million).

NOTE 15.
GUARANTEES AND INDEMNIFICATIONS

Guarantees

The Plan provides guarantees to third parties related to certain companies the Plan invests in and will be called upon to satisfy the guarantees if the companies fail to meet their obligations. The Plan expects most guarantees to expire unused. No payments have been made by the Plan in either 2014 or 2013 under these guarantees.

The Plan guarantees loan and credit agreements which will expire by 2017. The Plan's maximum exposure is $124 million as at December 31, 2014 (2013 – $116 million). The companies have drawn $112 million under the agreements (2013 – $115 million).

The Plan guarantees lease agreements for a subsidiary with expiry dates ranging from 2017 to 2059. The Plan's maximum exposure is $91 million as at December 31, 2014 (2013 – $92 million). There were no default lease payments in either 2014 or 2013.

The Plan also guarantees the ability of certain investee companies to settle certain financial obligations. The Plan's maximum exposure is $84 million as at December 31, 2014. There were no default payments in 2014.

The Cadillac Fairview Corporation Limited manages the real estate investments and has provided guarantees relating to the completion of the construction of certain residential developments. The term of these guarantees spans the lives of the development projects, which range from one to three years. The maximum exposure cannot be determined because the projects are not yet complete. These guarantees amounted to $95 million as at December 31, 2014 (2013 – $217 million) and have not been recognized in the real estate liabilities.

Indemnifications

The Plan provides that Board members, employees and certain others are to be indemnified in relation to certain proceedings that may be commenced against them. In addition, in the normal course of operations, the Plan may, in certain circumstances, agree to indemnify a counterparty. Under these agreements, the Plan, its subsidiaries and joint ventures may be required to compensate counterparties for costs incurred as a result of various contingencies such as legal claims or changes in laws and regulations. The number of such agreements, the variety of indemnifications and their contingent character prevents the Plan from making a reasonable estimate of the maximum amount that would be required to pay all such counterparties.

MAJOR INVESTMENTS

As at December 31, 2014

FIXED INCOME AND SHORT-TERM INVESTMENTS OVER $150 MILLION

Type (Canadian $ millions)	Maturity	Coupon (%)	Fair Value	Cost
Securities purchased under agreements to resell	2015–2015	-0.50–2.40	$ 24,137	$ 23,764
Government of Canada bonds	2015–2064	1.00–9.00	23,020	20,398
Provincial bonds	2015–2045	0.00–8.50	10,044	9,522
International corporate bonds	2015–2099	0.00–16.75	5,507	5,264
Canada treasury bills	2015–2015	0.00–0.00	3,649	3,642
Canadian corporate bonds	2015–2045	0.00–14.00	2,343	2,341
Commercial paper	2015–2015	0.00–0.00	797	795
Bank notes	2015–2015	0.00–0.05	592	589
International sovereign debt	2015–2068	0.00–12.00	402	393
International agency bonds	2015–2019	0.38–4.45	330	299
U.S. treasury bonds	2015–2044	0.25–6.25	(6,704)	(5,004)
Securities sold under agreements to repurchase	2015–2015	-0.85–2.75	(45,260)	(45,024)

REAL-RETURN INVESTMENTS OVER $150 MILLION

Type (Canadian $ millions)	Maturity	Coupon (%)	Fair Value	Cost
Real-return Canada bonds	2021–2047	1.25–4.25	$ 16,593	$ 13,026
U.S. treasury inflation protection	2019–2044	0.13–3.88	9,413	7,543
Real-return Canadian corporate bonds	2016–2046	0.00–5.33	1,967	845
Real-return provincial bonds	2021–2036	2.00–4.50	1,878	1,243

CORPORATE SHARES/UNITS OVER $150 MILLION

As at December 31, 2014 (millions)

Security Name	Shares	Fair Value
The Macerich Company	17.2	$1,658.6
Bank of America Corporation	63.7	1,320.5
Multiplan Empreendimentos Imobiliarios S.A.	54.8	1,142.0
iShares MSCI Emerging Markets Index	20.5	952.7
Hudson's Bay Company	30.7	754.9
ISS A/S	22.4	750.7
INC Research Holdings, Inc.	24.9	672.9
JD.com, Inc.	22.1	592.1
Microsoft Corporation	7.0	374.8
Wells Fargo & Company*	5.3	303.8
Nissan Shatai Co., Ltd.	20.1	286.1
General Motors Company	6.4	258.5
Volkswagen AG	0.9	239.3
JPMorgan Chase & Co.*	3.3	238.8
American International Group, Inc.	3.6	236.8
TMX Group Limited	4.6	235.0
Danone	2.9	222.6
Amazon.com, Inc.	0.6	219.7
Samsung Electronics Co., Ltd.	0.2	212.7
Compagnie Financière Richemont SA	2.1	212.4
Zalando SE	0.7	210.6
Barclays PLC	47.7	209.8
Grupo BTG Pactual	16.6	203.4
ACE Limited	1.5	198.7
Citigroup Inc.	3.2	198.5
The Walt Disney Company	1.8	198.2
Aircastle Limited	7.9	$195.2
Google Inc.	0.3	194.6
Daimler AG	2.0	191.7
Twenty-First Century Fox, Inc.	4.2	188.2
Thermo Fisher Scientific Inc.	1.3	186.1
Macdonald, Dettwiler and Associates Ltd.	2.0	185.4
European Aeronautic Defence and Space Company NV	3.2	184.8
Baidu, Inc.	0.7	183.2
Metlife, Inc.	2.9	179.2
Tripadvisor, Inc.	2.1	177.4
Capital One Financial Corporation*	1.9	175.2
Credit Suisse Group AG	5.9	173.7
Exor S.p.A	3.6	173.2
Western Digital Corporation	1.3	169.4
General Mills, Inc.	2.7	169.4
Hitachi, Ltd.	19.3	167.7
Constellium N.V.	8.6	162.9
Cheung Kong (Holdings) Limited	8.4	162.6
Oi S.A.	42.0	159.6
Novartis AG	1.5	159.4
Nokia Corporation	17.3	159.3
NuVista Energy Ltd.	21.5	159.1
Bunge Limited	1.5	156.4
BNP Paribas S.A.	2.2	153.0
Telefonaktiebolaget LM Ericsson	10.8	151.0

* Includes fair market value of warrants and subscription receipts.

REAL ESTATE PROPERTIES OVER $150 MILLION

As at December 31, 2014

Property	Total Square Footage (in thousands)	Effective % Ownership
Canadian Regional Shopping Centres		
Champlain Place, Dieppe	853	100%
Chinook Centre, Calgary	1,375	100%
Fairview Mall, Toronto	875	50%
Fairview Park Mall, Kitchener	746	100%
Fairview Pointe Claire, Montreal	1,053	50%
Le Carrefour Laval, Montreal	1,355	100%
Les Galeries D'Anjou, Montreal	1,355	50%
Les Promenades St. Bruno, Montreal	1,133	100%
Lime Ridge Mall, Hamilton	806	100%
Market Mall, Calgary	970	50%
Markville Shopping Centre, Markham	1,017	100%
Masonville Place, London	561	100%
Pacific Centre, Vancouver	798	100%
Polo Park Mall, Winnipeg	1,199	100%
Richmond Centre, Richmond	771	50%
Rideau Centre, Ottawa	1,155	100%
Sherway Gardens, Toronto	712	100%
Shops at Don Mills, Toronto	470	100%
The Promenade, Toronto	704	100%
Toronto-Dominion Centre, Toronto	158	100%
Toronto Eaton Centre, Toronto	2,560	100%

Property	Total Square Footage (in thousands)	Effective % Ownership
Canadian Office Properties		
Encor Place, Calgary	359	100%
Granville Square, Vancouver	403	100%
HSBC Building, Vancouver	395	100%
Pacific Centre Office Complex, Vancouver	1,531	100%
RBC Centre, Toronto	1,226	50%
Shell Centre, Calgary	692	100%
Simcoe Place, Toronto	759	25%
Toronto-Dominion Centre Office Complex, Toronto	4,434	100%
Toronto Eaton Centre Office Complex, Toronto	1,901	100%
Waterfront Centre, Vancouver	402	100%
Yonge Corporate Centre, Toronto	670	100%
Properties Under Development		
City Centre Office, Calgary	n/a	100%
Deloitte Tower, Montreal	n/a	100%
Ice Residential, Toronto	n/a	50%

PRIVATE COMPANIES AND PARTNERSHIPS OVER $150 MILLION

As at December 31, 2014

24 Hour Fitness Worldwide Inc.
Acorn Care and Education Limited
Alliance Laundry Systems, LLC
ANV Holdings BV
Apollo Overseas Partners (Delaware 892) VI, L.P.
AQR Offshore Multi-Strategy Fund VII Ltd.
Ares Corporate Opportunities Fund III, L.P.
Ares Corporate Opportunities Fund IV, L.P.
Ascend Learning Holdings, LLC
Asia Opportunity Fund III, L.P.
Baldr Fund Inc.
Baybridge Seniors Housing Inc.
BC European Capital IX-1 LP
BC European Capital VIII-1
BDCM Offshore Opportunity Fund II, Ltd.
Birmingham International Airport
Blue Coat Systems, Inc.
Bridgewater Pure Alpha Fund II Ltd.
Bridon Limited
Bristol Airports (Bermuda) Limited
BroadStreet Capital Partners, Inc.
Burton's Biscuit Company
Busy Bees Benefits Holdings Limited
Camelot Group plc
Canada Guaranty Mortgage Insurance Company
Canbriam Energy, Inc.
Copenhagen Airport A/S
Coway Holdings, Inc.
CPG International Inc.
CSC ServiceWorks Holdings, Inc.
DaVinciRe Holdings Ltd.
Dematic S.A.
Downsview Managed Account Platform Inc.
Empresa de Servicios Sanitarios del Bio-Bio S.A.
Esval S.A.
Exal International Limited
First Data Holdings Inc.
Flexera Holdings, L.P.
Flynn Restaurant Group LLC
FountainVest China Growth Fund, L.P.
GCT Global Container Terminals Inc.
GMO Mean Reversion Fund (Offshore) L.P.
Hancock Timber Resource Group
Heartland Dental Care, Inc.
Helly Hansen Group AS
HS1 Limited
Hudson Catastrophe Fund, Ltd.
HUGO BOSS AG
Imperial Parking Corporation
InterGen N.V.
Irish National Lottery
Kepos Alpha Fund Ltd.
Kyobo Life Insurance Co., Ltd.
LMAP Chi Limited
LMAP Iota Limited
Louis XIII Holdings Limited
Lowell Group Limited
MBK Partners Fund II, L.P.
MBK Partners, L.P.
Munchkin, Inc.
MW Market Neutral TOPS Fund
Nextgen Group Holdings Pty Limited
Nuevosur, S.A.
NXT Capital Holdings, L.P.
OLE Media Management, L.P.
Orbis SICAV Global Equity Fund
PetVet Care Centers, Inc.
PhyMed Healthcare Group
Plano Molding Company
Providence Equity Partners VI L.P.
Resource Management Service Inc.
Scotia Gas Networks plc
SeaCube Container Leasing Ltd.
Serta Simmons Holdings, LLC
Shearer's Foods, Inc.
Silver Lake Partners III, L.P.
Sociedad Austral de Electricidad S.A.
Sydney Desalination Plant Pty Limited
TDR Capital II, L.P.
Terranum Corporate Properties
The Brussels Airport Company
TP Partners Fund, L.P.
Univision Communications Inc.
ValueAct Capital International II, L.P.

ELEVEN-YEAR FINANCIAL REVIEW

(Canadian $ billions)	**2014**	2013	2012	2011	2010	2009	2008	2007	2006	2005	2004
CHANGE IN NET ASSETS											
Income											
Investment income	**$16.26**	$13.72	$14.75	$11.74	$13.27	$10.89	$(19.03)	$4.68	$12.31	$14.09	$10.80
Contributions											
Members/transfers	**1.63**	1.55	1.48	1.41	1.35	1.29	1.13	1.06	0.83	0.79	0.75
Province of Ontario	**1.59**	1.53	1.46	1.41	1.35	1.43	1.18	1.08	0.82	0.78	0.75
Total income	**19.48**	16.80	17.69	14.56	15.97	13.61	(16.72)	6.82	13.96	15.66	12.30
Expenditures											
Benefits paid	**5.31**	5.15	4.92	4.66	4.50	4.39	4.20	4.02	3.82	3.62	3.43
Investment expenses	**0.41**	0.36	0.30	0.29	0.29	0.21	0.15	0.23	0.22	0.21	0.19
Member services expenses	**0.05**	0.05	0.04	0.05	0.05	0.04	0.04	0.04	0.03	0.03	0.03
Total expenditures	**5.77**	5.56	5.26	5.00	4.84	4.64	4.39	4.29	4.07	3.86	3.65
Increase/(decrease) in net assets	**$13.71**	$11.24	$12.43	$9.56	$11.13	$8.97	$(21.11)	$2.53	$9.89	$11.80	$8.65
NET ASSETS											
Investments											
Fixed income											
Bonds	**$35.19**	$30.53	$28.87	$26.50	$22.73	$15.46	$14.22	$22.91	$20.86	$5.28	$8.96
Real-rate products	**30.36**	26.37	31.14	29.29	23.24	19.88	17.41	11.06	11.80	10.56	11.90
Equities											
Canadian	**10.71**	10.86	11.40	10.64	9.29	8.43	6.21	13.73	16.39	19.26	16.80
Non-Canadian	**58.14**	51.03	48.11	41.03	38.20	32.75	28.72	36.31	32.42	25.78	23.09
Natural resources											
Commodities	**9.03**	8.21	6.97	5.64	5.22	1.94	1.25	3.02	2.32	2.65	2.13
Timberland	**2.59**	2.45	2.17	2.17	2.22	2.34	2.80	2.12	2.05	0.97	0.70
Sector investment	**0.28**	0.17	–	–	–	–	–	–	–	–	–
Real assets											
Real estate	**22.09**	19.24	16.86	14.96	16.86	14.21	13.48	13.41	11.12	8.75	7.20
Infrastructure	**12.66**	11.68	9.65	8.71	7.07	5.57	7.23	6.72	4.73	3.80	2.29
Absolute return strategies	**15.84**	12.20	12.27	12.33	11.38	11.67	14.75	12.30	15.21	9.49	11.18
Money market	**(44.50)**	(33.84)	(40.18)	(35.01)	(31.49)	(18.74)	(20.97)	(13.58)	(11.22)	8.26	(2.53)
Net investments	**152.39**	138.90	127.26	116.26	104.72	93.51	85.10	108.00	105.68	94.80	81.72
Receivable from Province of Ontario	**3.10**	2.97	2.83	2.72	2.63	2.52	2.19	1.84	1.58	1.50	1.42
Other assets	**73.01**	59.34	47.96	40.81	32.04	15.21	32.33	32.06	23.14	10.67	18.23
Total assets	**228.50**	201.21	178.05	159.79	139.39	111.24	119.62	141.90	130.40	106.97	101.37
Liabilities	**(74.02)**	(60.45)	(48.53)	(42.69)	(31.86)	(14.84)	(32.18)	(33.35)	(24.39)	(10.84)	(17.04)
Net assets	**154.48**	140.76	129.52	117.10	107.53	96.40	87.44	108.55	106.01	96.13	84.33
Accrued pension benefits	**172.73**	148.57	166.01	162.59	146.89	131.86	118.14	115.46	110.50	110.53	96.73
Deficit	**$(18.25)**	$(7.81)	$(36.49)	$(45.49)	$(39.36)	$(35.46)	$(30.70)	$(6.91)	$(4.49)	$(14.40)	$(12.40)
PERFORMANCE (percent)											
Rate of return	**11.8**	10.9	13.0	11.2	14.3	13.0	(18.0)	4.5	13.2	17.2	14.7
Benchmark	**10.1**	9.3	11.0	9.8	9.8	8.8	(9.6)	2.3	9.4	12.7	10.6

FUNDING VALUATION HISTORY

Funding valuations must be filed with pension regulatory authorities at least every three years. Valuation dates and voluntary filings are determined by OTF and the Ontario government. Filings must show the plan has sufficient assets to pay all future benefits to current plan members. The 10 most recent filed funding valuations and the assumptions used for each are summarized in the table below. Details on plan changes from funding decisions are available in the Plan Funding section at otpp.com.

In the 2014 filing, the sponsors used the $5.1 billion preliminary funding valuation to boost pensions of members who retired after 2009 to the level they would have been at if full inflation protection had been provided each year since they retired. The surplus funds were also used to raise conditional inflation protection to 60% of the increase in the cost of living for the portion of retirees' pensions earned after 2009. Both changes are effective with January 2015 pension payments.

FILED FUNDING VALUATIONS[1]

As at January 1 (Canadian $ billions)	**2014**	2012	2011	2009	2008	2005	2003	2002	2001	2000
Net assets available for benefits	**$140.8**	$117.1	$107.5	$87.4	$108.5	$84.3	$66.2	$69.5	$73.1	$68.3
Smoothing adjustment	**(7.2)**	(3.0)	3.3	19.5	(3.6)	(1.5)	9.7	3.0	(4.3)	(7.3)
Value of assets	**133.6**	114.1	110.8	106.9	104.9	82.8	75.9	72.5	68.8	61.0
Future basic contributions	**37.5**	35.4	33.8	25.9	23.6	16.7	14.7	13.7	12.7	13.4
Future special contributions	**3.5**	3.3	3.8	5.5	5.6	6.2	–	–	–	–
Future matching of CIP benefit reduction	**7.4**	7.3	5.1	–	–	–	–	–	–	–
Total assets	**182.0**	160.1	153.5	138.3	134.1	105.7	90.6	86.2	81.5	74.4
Cost of future pensions[2]	**(188.2)**	(167.6)	(158.4)	(137.5)	(134.1)	(105.6)	(89.1)	(84.3)	(80.9)	(69.9)
Reduction in cost due to less than 100% indexing	**7.4**	7.7	5.1	–	–	–	–	–	–	–
Surplus	**$1.2**	$0.2	$0.2	$0.8	$0.0	$0.1	$1.5	$1.9	$0.6	$4.5

[1] Valuation filing dates determined by the plan sponsors.

[2] Includes value of 100% inflation protection.

ASSUMPTIONS USED FOR FILED VALUATIONS

As at January 1 (percent)	**2014**	2012	2011	2009	2008	2005	2003	2002	2001	2000
Inflation rate	**2.10**	2.20	2.15	1.35	2.20	2.750	2.05	1.90	2.20	2.25
Real discount rate	**2.85**	3.10	3.25	3.65	3.45	3.725	4.35	4.40	4.05	4.25
Discount rate	**4.95**	5.30	5.40	5.00	5.65	6.475	6.40	6.30	6.25	6.50

CORPORATE DIRECTORY

ONTARIO TEACHERS' PENSION PLAN

Ron Mock,
President and CEO

Audit Services

Carol Gordon, VP

Finance

David McGraw, SVP and Chief Financial Officer
Hersh Joshi, VP, Taxation
Calum McNeil, VP, Financial & Management Reporting
Peter Simpson, VP, Valuation, Risk Analytics & Model Validation

General Counsel's Office

Jeff Davis, General Counsel, SVP, Corporate Affairs and Corporate Secretary
Deborah Allan, VP, Communications & Media Relations
Rossana Di Lieto, VP, Chief Compliance Officer
Stephen Solursh, VP and Associate General Counsel

Human Resources & Facilities

Marcia Mendes-d'Abreu, SVP

Operations

Rosemarie McClean, SVP and Chief Operations Officer
Russ Bruch, SVP and Chief Information Officer
Jacqueline Beaurivage, VP, Head of the enterprise Project Management Office
Douglas Gerhart, VP, Investment IT Architecture
Maryam Ghiai, VP, IT Service Delivery
Jonathan Hammond, VP, Enterprise Technology Services
Jennifer Newman, VP, Financial Operations & Data Management

Member Services Division

Tracy Abel, SVP

Investment Division

Neil Petroff,
EVP and Chief Investment Officer

Asset Mix & Risk

Barbara Zvan, SVP and Chief Investment Risk Officer
James Davis, VP, Strategy & Asset Mix, Chief Economist
Audrey Gaspar, VP, Investment Planning & Asset Liability Modelling
Scott Picket, VP, Research & Risk

Fixed Income & Alternative Investments

Wayne Kozun, SVP
Jason Chang, VP, Fixed Income
Jonathan Hausman, VP, Alternative Investments & FI Emerging Markets

Infrastructure

Andrew Claerhout, SVP
Ken Manget, VP
Olivia Steedman, VP

Public Equities

Michael Wissell, SVP
Leslie Lefebvre, VP, Global Active Equities

Tactical Asset Allocation & Natural Resources

Ziad Hindo, SVP
Kevin Duggan, VP, Equity Products
Stephen McLennan, VP, Natural Resources

Teachers' Private Capital

Jane Rowe, SVP
Steve Faraone, VP, Healthcare & Consumer Retail
Romeo Leemrijse, VP, Industrial Products, Energy & Power
Nicole Musicco, VP, Funds
Lee Sienna, VP, Long-Term Equities
Jo Taylor, Managing Director, Europe, Middle East & Africa

Investment Operations

Dan Houle, VP

The Cadillac Fairview Corporation Limited

John M. Sullivan,
President and CEO
Wayne L. Barwise,
EVP, Development
Cathal J. O'Connor,
EVP and Chief Financial Officer

Sandra J. Hardy,
EVP, General Counsel and Secretary
Russell Goin,
EVP, Investments
Ron Wratschko,
EVP, Portfolio Operations
Norm Sabapathy,
EVP, People

ANNUAL MEETING

April 9, 2015 at 4:45 p.m. ET
The Carlu
444 Yonge Street, 7th floor
Toronto

We welcome your comments and suggestions on this annual report.

CONTACT US

Ontario Teachers' Pension Plan

5650 Yonge Street
Toronto, Ontario M2M 4H5
416-228-5900
communications@otpp.com

London U.K. Office

Leconfield House, Curzon Street
London W1J 5JA
+44 20 7659 4450

Ontario Teachers' Pension Plan (Asia) Limited

安大略省教師退休金計劃（亞洲）有限公司
28/F Alexandra House
18 Chater Road, Central Hong Kong
+852 2230 4500

Concept and Design: THE WORKS DESIGN COMMUNICATIONS LTD. www.worksdesign.com

Every day, in schools and classrooms across the province, Ontario's teachers are helping to build our future. From the day it was founded in 1990, Teachers' has helped to build their future. For 25 years, as an independent organization responsible for paying pensions and investing plan assets, Teachers' has worked to keep a promise:

Outstanding service and retirement security for our members – today and tomorrow

Attachment 40.3

United States: Utilities

Equity Research

Regulatory Rundown: Regulatory catalysts through 4Q2015; remain Neutral on Utilities

Our "Rundown" highlights key regulatory events and rate cases for Utilities

In this calendar, we highlight the key upcoming regulatory events, providing near-term catalysts for select companies in our universe. As detailed in Exhibits 1-2, we monitor general rate case (GRC) filings and resolutions, approvals for key projects, changes in state public commission structures, and other regulatory events.

We remain Neutral on Utilities

We maintain our Neutral coverage view on the broader utilities sector, while still Attractive on IPPs, as the anticipated increase in interest rates remains a technical headwind for traditional utilities.

Our approach to utility investing focuses on lower multiple stocks with above average growth in earnings and capital allocation. Among the large caps, NEE, EIX, SRE and WEC remain favorites. Within smaller cap names, we prefer GXP and PPL, while still Buy rated on IPPs such as CPN, DYN, and NYLD.

Key regulatory events to monitor through 4Q15:

(1) **Neutral-rated AEP and Sell rated FE in focus,** with a decision expected on whether each company is allowed to create a PPA between their regulated and merchant power segments. Our numbers do not include a PPA.

(2) **California dream or a California startle scenario potentially ahead in 4Q15 –** as EIX awaits a final rate case order, one where based on the ALJ proposed decision, could imply very modest downside to our EPS estimates. A decision on reopening the San Onofre docket also may occur – we view this as a risk to the NT multiple, but less so to earnings – a 1-2pct impact could occur even in bear case outcomes.

(3) **Monitor court rulings in the Magnolia State–** as a potential decision should emerge in the state Supreme Court case on the rate increase approved by the state regulator for the Kemper County plant.

RELATED RESEARCH

Regulatory Rundown: Regulatory catalysts through 3Q2015; remain Neutral on Utilities, June 17, 2015

Regulatory Rundown: Regulatory catalysts through 1Q2015 still Cautious on Utilities, October 5, 2014

Regulatory Rundown: Regulatory catalysts through 3Q14; remain Neutral Utilities, April 14, 2014

RATINGS DISTRIBUTION

	Regulated Utilities (Neutral)	Diversified Utilities (Neutral)	IPPs (Attractive)
Buy	EIX, GXP, WEC*	SRE*, NEE PPL	CPN, DYN, NYLD
Neutral	AEE, AEP, AWK, DUK, ED, ES PCG, PNW, POR, WR	CNP, D PEG	NRG NEP
Sell	SCG	ETR, FE	
Not Rated	CNL, SO	EXC	
Covergage Suspended		OGE	

*Conviction Buy List

Source: Goldman Sachs Global Investment Research.

Michael Lapides
(212) 357-6307 michael.lapides@gs.com Goldman, Sachs & Co.

David Fishman
(917) 343-9030 david.fishman@gs.com Goldman, Sachs & Co.

Dylan Campbell
(801) 884-1539 dylan.campbell@gs.com Goldman, Sachs & Co.

Many important rate case dockets lie ahead in 4Q 2015

Exhibit 1: Multiple regulatory catalysts in the coming months provide near-term catalysts for Regulated Utilities
Timeline of the key regulatory events through 4Q 2015

Event Date	Event Type	Jurisdiction	Operating Company	Parent Company	Docket Number	Action
4Q2015	Other	OH		AEP/FE		Decision expected on allowance of PPA between each company's Merchant Generation and Regulated businesses
Potentially 4Q2015	Other	CA	Southern California Edison Co.	EIX	15-CV-01478-BEN-JMA	Decision on Class Action lawsuit regarding San Onofre proceeding
10/6/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00061 (Rider W)	Intervenor testimony due in Rider W proceeding
10/6/2015	Rate Case	VA	Kentucky Utilities Co.	PPL	C-PUE-2015-00063	Intervening parties to file direct testimony in rate case
10/8/2015	Other	FL	Florida Power & Light Co.	NEE	150009-EI	PSC Staff recommendation expected in nuclear cost recovery proceeding
10/13/2015	Other	NJ	Public Service Electric Gas	PEG	D-GR15030272	Hearings to begin in gas modernization plan proceeding
10/14/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00059 (Rider R)	SCC Staff testimony due in annual Rider R proceeding
10/14/2015	Rate Case	OK	Public Service Co. of OK	AEP	Ca-PUD201500208	Staff and intervenor testimony due in rate proceeding
10/15/2015	Rate Case	CA	Southern California Edison Co.	EIX	A-13-11-003	PUC decision expected in general electric rate case
10/19/2015	Other	FL	Florida Power & Light Co.	NEE	150009-EI	PSC decision expected in nuclear cost recovery proceeding
10/20/2015	Rate Case	TX	CenterPoint Energy Resources	CNP	D-GUD-10432	RRC decision expected in rate case
10/20/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00061 (Rider W)	Staff testimony due in Rider W proceeding
10/22/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00060 (Rider S)	Intervenor testimony due in annual Rider S proceeding
10/27/2015	Rate Case	AR	Entergy Arkansas Inc.	ETR	D-15-015-U	Company rebuttal testimony due in rate proceeding
10/28/2015	Rate Case	KS	Westar Energy Inc.	WR	D-15-WSEE-115-RTS	Decision expected in rate proceeding
10/28/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00059 (Rider R)	Rebuttal testimony due in annual Rider R proceeding
10/30/2015	Rate Case	OR	Portland General Electric Co.	POR	D-UE-294	Final order expected to be issued in rate case
10/30/2015	Rate Case	PA	PECO Energy Co.	EXC	D-R-2015-2468981	ALJ recommended decision likely (estimated by RRA)
10/31/2015	Rate Case	NY	Orange & Rockland Utlts Inc.	ED	C-14-E-0493	Final decision expected in electric rate case
10/31/2015	Rate Case	NY	Orange & Rockland Utlts Inc.	ED	C-14-G-0494	Final decision expected in gas rate case
10/31/2015	Rate Case	PA	PPL Electric Utilities Corp.	PPL	D-R-2015-2469275	ALJ recommended decision likely (estimated by RRA)
10/31/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00027	Hearing Examiner recommendation likely to be issued during October in biennial review proceeding (estimated by R
11/1/2015 - 11/30/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00059 (Rider R)	Hearings may be held in Rider R proceeding (estimated by RRA)
11/3/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00061 (Rider W)	Rebuttal testimony due in Rider W proceeding
11/3/2015	Rate Case	IL	Ameren Illinois	AEE	D-15-0142	ALJ recommendation due in rate proceeding
11/3/2015	Other	LA	Cleco Corp.	CNL	U-33434	Pre-hearing briefs due in merger proceeding
11/5/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00075 (Rider GV)	Intervening parties to file testimony in Rider GV proceeding
11/9/2015 - 11/13/2015	Other	LA	Cleco Corp.	CNL	U-33434	Hearings to be held in merger proceeding
11/10/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00060 (Rider S)	SCC Staff testimony due in annual Rider S proceeding
11/10/2015	Rate Case	OK	Public Service Co. of OK	AEP	Ca-PUD201500208	Rebuttal testimony due in rate proceeding
11/10/2015	Rate Case	IL	Ameren Illinois	AEE	D-15-0305	ALJ recommendation due in formula rate plan proceeding
11/10/2015	Other	MS	Mississippi Power Co.	SO	2015-UN-0080	Hearing to be held in Kemper proceeding
11/16/2015	Rate Case	VA	Kentucky Utilities Co.	PPL	C-PUE-2015-00063	SCC Staff to file testimony in rate case
11/20/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00075 (Rider GV)	Staff to file testimony in Rider GV proceeding
11/24/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00060 (Rider S)	Rebuttal testimony due in annual Rider S proceeding
11/30/2015	Rate Case	VA	Kentucky Utilities Co.	PPL	C-PUE-2015-00063	Interim rate increase may be implemented in rate case
11/30/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00027	Decision expected in biennial review proceeding
12/1/2015	Rate Case	CA	Southern California Gas Co.	SRE	A-14-11-004	ALJ's Proposed Decision expected in general gas rate case
12/1/2015	Rate Case	CA	San Diego Gas & Electric Co.	SRE	A-14-11-003 (Elec)	ALJ's Proposed Decision expected in general electric rate case
12/1/2015	Rate Case	CA	San Diego Gas & Electric Co.	SRE	A-14-11-003 (Gas)	ALJ's Proposed Decision expected in general gas rate case
12/3/2015	Rate Case	VA	Kentucky Utilities Co.	PPL	C-PUE-2015-00063	Rebuttal testimony due in rate case
12/4/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00058 (Rider B)	Parties to file testimony in Rider B proceeding
12/7/2015	Rate Case	MI	Consumers Energy Co.	CMS	C-U-17735	PSC order required in general electric rate case
12/7/2015	Rate Case	VA	Kentucky Utilities Co.	PPL	C-PUE-2015-00063	Public comments due in rate case
12/8/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00058 (Rider B)	SCC Staff to file testimony in Rider B proceeding
12/8/2015	Rate Case	OK	Public Service Co. of OK	AEP	Ca-PUD201500208	Hearing to begin in rate proceeding
12/8/2015	Other	MS	Mississippi Power Co.	SO	2015-UN-0080	Final PSC decision expected in Kemper proceeding
12/9/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00060 (Rider S)	Hearings to start in annual Rider S proceeding
12/11/2015	Rate Case	IL	Commonwealth Edison Co.	EXC	D-15-0287	Statutory deadline for decision in formula rate plan proceeding
12/14/2015	Rate Case	VA	Kentucky Utilities Co.	PPL	C-PUE-2015-00063	Evidentiary hearing scheduled in rate case
12/15/2015	Rate Case	VA	Virginia Electric & Power Co.	D	C-PUE-2015-00075 (Rider GV)	Rebuttal testimony to be filed in Rider GV proceeding
12/16/2015	Rate Case	IL	Ameren Illinois	AEE	D-15-0142	Deadline for decision in rate proceeding
12/17/2015	Rate Case	PA	PPL Electric Utilities Corp.	PPL	D-R-2015-2469275	PUC to discuss rate case at public meeting
12/20/2015	Rate Case	IL	Ameren Illinois	AEE	D-15-0305	Statutory deadline for decision in formula rate plan proceeding
12/26/2015	Rate Case	PA	PECO Energy Co.	EXC	D-R-2015-2468981	PUC decision due in rate case
12/31/2015	Rate Case	MA	NSTAR Gas Co.	ES	DPU 14-150	Final decision expected in rate case
12/31/2015	Rate Case	NY	Consolidated Edison Co. of NY	ED	C-15-E-0050/C-13-E-0030 (Ext)	Final decision expected in rate case

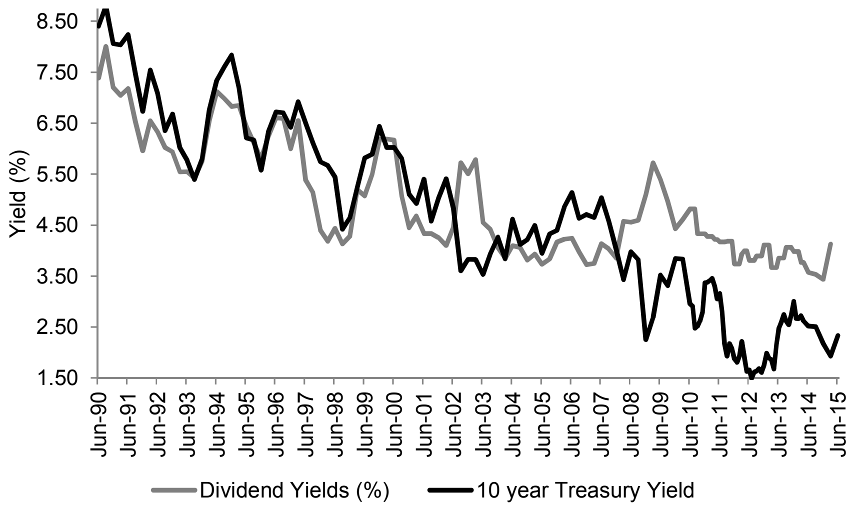
Source: Company data, SNL Energy, Goldman Sachs Global Investment Research

Exhibit 2: Changes in the commissioner structure for key jurisdictions have the potential of changing our long-term views of those regulatory environments
Schedule for commissioner turnover through 4Q2015

Event Date	Jurisdiction	Action
11/1/2015 - 11/30/2015	OR	Commissioner Stephen Bloom - Term Expires
12/1/2015 - 12/31/2015	MS	Commissioner Irvin Posey - Term Expires
12/1/2015 - 12/31/2015	MS	Commissioner Steve Renfroe - Term Expires
12/1/2015 - 12/31/2015	MS	Commissioner Brandon Presley - Term Expires

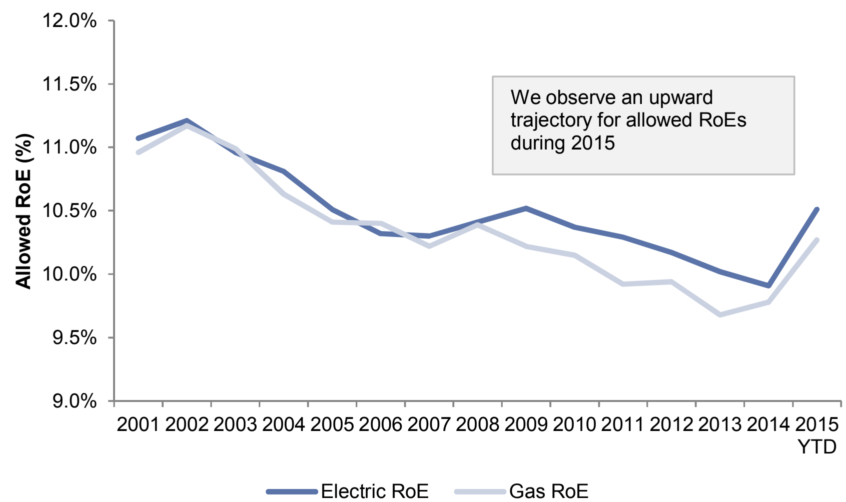
Source: SNL Energy, Goldman Sachs Global Investment Research

Exhibit 3: Treasury Yield's begin to rebound in 2015
US 10-year Treasury Yield, 1990-Present



Source: Factset, Goldman Sachs Global Investment Research

Exhibit 4: ....resulting in an increasing trend in the authorized RoEs for Regulated Utilities
Historical national allowed RoEs, electric and gas segments



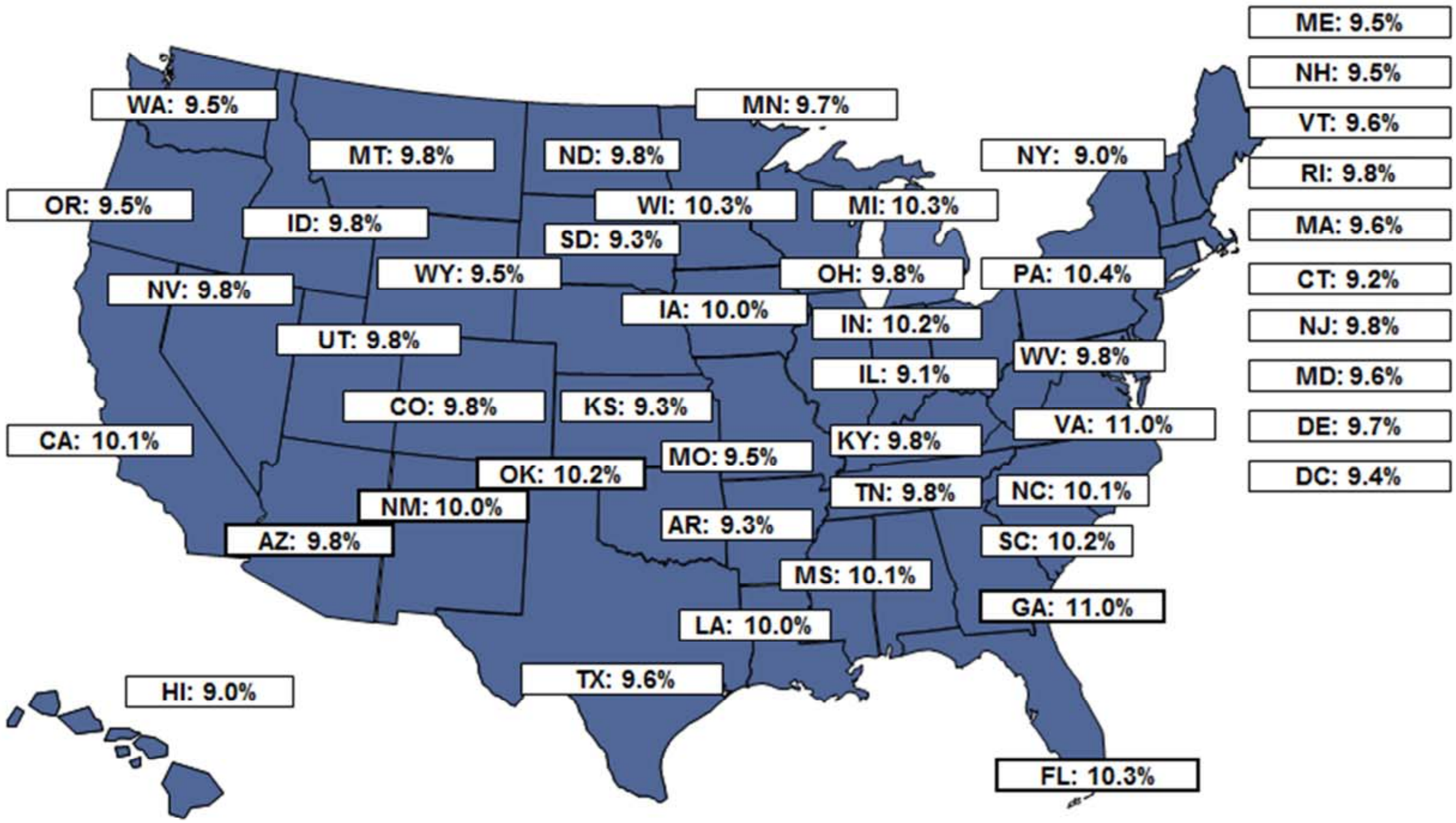
Source: SNL Energy, Goldman Sachs Global Investment Research

Exhibit 5: In 2015 so far, the average authorized return on equity came in at 10.5% for electric cases and 10.3% for gas cases
List of major resolved cases in 2015:

				Increase Requested			Increase Authorized			Delta allowed vs requested RoE
State	Company	Case Identification	Service	Date	Rate Increase ($m)	Return on Equity (%)	Date	Rate Increase ($m)	Return on Equity (%)	
Colorado	Public Service Co. of CO	D-14AL-0660E	Electric	6/17/2014	$29	10.3%	2/24/2015	($39)	9.8%	-0.4%
Illinois	North Shore Gas Co.	D-14-0224	Natural Gas	2/26/2014	$7	10.3%	1/21/2015	$4	9.1%	-1.2%
Illinois	Peoples Gas Light & Coke Co.	D-14-0225	Natural Gas	2/26/2014	$101	10.3%	1/21/2015	$71	9.1%	-1.2%
Indiana	Indiana Gas Co.	Ca-44430-TDSIC-2	Natural Gas	4/1/2015	$7	NA	7/22/2015	$6	NA	NA
Indiana	Indiana Gas Co.	Ca-44430-TDSIC-1	Natural Gas	10/1/2014	$6	NA	1/14/2015	$6	NA	NA
Indiana	Northern IN Public Svc Co.	Ca-44403-TDSIC-1	Natural Gas	8/28/2014	$0	NA	1/28/2015	$0	NA	NA
Indiana	Southern Indiana Gas & Elec Co	Ca-44429-TDSIC-2	Natural Gas	4/1/2015	$4	NA	7/22/2015	$3	NA	NA
Indiana	Southern Indiana Gas & Elec Co	Ca-44429-TDSIC-1	Natural Gas	10/1/2014	$2	NA	1/14/2015	$2	NA	NA
Kansas	Atmos Energy Corp.	(GSRS)	Natural Gas	4	$0	NA	1/27/2015	$0	NA	NA
Kansas	Kansas City Power & Light	D-15-KCPE-116-RTS	Electric	1/2/2015	$56	10.3%	9/10/2015	$40	9.3%	-1.0%
Kentucky	Delta Natural Gas Co.	C-2015-00066 (PRP)	Natural Gas	2/27/2015	$1	NA	4/7/2015	$1	NA	NA
Kentucky	Kentucky Power Co.	C-2014-00396	Electric	4	($5)	10.6%	6/22/2015	($23)	NA	NA
Kentucky	Kentucky Utilities Co.	C-2014-00371	Electric	4	$153	10.5%	6/30/2015	$125	NA	NA
Kentucky	Louisville Gas & Electric Co.	C-2014-00372 (elec.)	Electric	4	$30	10.5%	6/30/2015	$0	NA	NA
Kentucky	Louisville Gas & Electric Co.	C-2014-00372 (gas)	Natural Gas	4	$14	10.5%	6/30/2015	$7	NA	NA
Michigan	Consumers Energy Co.	C-U-17643	Natural Gas	7/1/2014	$88	10.7%	1/13/2015	$45	10.3%	-0.4%
Michigan	Wisconsin Public Service Corp.	C-U-17669	Electric	4	$6	10.6%	4/23/2015	$4	10.2%	-0.4%
Minnesota	Northern States Power Co. - MN	Rider)	Natural Gas	8/1/2014	$15	NA	1/27/2015	$15	NA	NA
Minnesota	Northern States Power Co. - MN	D-E-002/GR-13-868	Electric	11/4/2013	$248	10.3%	3/26/2015	$149	9.7%	-0.5%
Missouri	Empire District Electric Co.	C-ER-2014-0351	Electric	8/29/2014	$24	10.2%	6/24/2015	$17	NA	NA
Missouri	Kansas City Power & Light	C-ER-2014-0370	Electric	4	$113	10.3%	9/2/2015	$90	9.5%	-0.8%
Missouri	Laclede Gas Co.	C-GO-2015-0269 (ISRS)	Natural Gas	4/17/2015	$6	NA	5/20/2015	$6	NA	NA
Missouri	Laclede Gas Co.	C-GO-2015-0178 (ISRS)	Natural Gas	1/30/2015	$5	NA	4/16/2015	NA	NA	NA
Missouri	Missouri Gas Energy	C-GO-2015-0270 (ISRS)	Natural Gas	4/17/2015	$3	NA	5/13/2015	$3	NA	NA
Missouri	Missouri Gas Energy	C-GO-2015-0179 (ISRS)	Natural Gas	1/30/2015	$3	NA	4/16/2015	NA	NA	NA
Missouri	Union Electric Co.	C-ER-2014-0258	Electric	7/3/2014	$181	10.4%	4/29/2015	$122	9.5%	-0.9%
Mississippi	Mississippi Power Co.	D-2013-UN-0014	Electric	1/25/2013	$171	9.7%	7/7/2015	$0	NA	NA
North Carolina	Piedmont Natural Gas Co.	D-G-9, Sub 659 (IMR)	Natural Gas	12/1/2014	$27	NA	1/26/2015	$27	NA	NA
New Hampshire	Liberty Utilities EnergyNorth	D-DG-14-180	Natural Gas	8/1/2014	$13	10.3%	6/26/2015	$11	NA	NA
New Jersey	Jersey Cntrl Power & Light Co.	D-ER-12111052	Electric	2	$11	11.0%	3/18/2015	($115)	9.8%	-1.3%
New Mexico	Public Service Co. of NM	C-14-00332-UT	Electric	4	$107	10.5%	5/13/2015	NA	NA	NA
New Mexico	Southwestern Public Service Co	C-15-00139-UT	Electric	6/8/2015	$32	10.3%	6/24/2015	NA	NA	NA
New York	Central Hudson Gas & Electric	C-14-E-0318	Electric	7/25/2014	$40	9.0%	6/17/2015	$15	9.0%	0.0%
New York	Central Hudson Gas & Electric	C-14-G-0319	Natural Gas	7/25/2014	$6	9.0%	6/17/2015	$2	9.0%	0.0%
New York	Consolidated Edison Co. of NY	(Ext)	Electric	1/30/2015	$368	10.0%	6/17/2015	NA	9.0%	-1.0%
Oklahoma	Public Service Co. of OK	Ca-PUD201300217	Electric	1/17/2014	$38	10.5%	4/14/2015	($5)	NA	NA
Oregon	Avista Corp.	D-UG-284	Natural Gas	9/2/2014	$9	9.9%	4/9/2015	$5	9.5%	-0.4%
Pennsylvania	Metropolitan Edison Co.	D-R-2014-2428745	Electric	8/4/2014	$168	10.9%	4/9/2015	$106	NA	NA
Pennsylvania	Pennsylvania Electric Co.	D-R-2014-2428743	Electric	8/4/2014	$137	10.9%	4/9/2015	$108	NA	NA
Pennsylvania	Pennsylvania Power Co.	D-R-2014-2428744	Electric	8/4/2014	$38	10.9%	4/9/2015	$26	NA	NA
Pennsylvania	West Penn Power Co.	D-R-2014-2428742	Electric	8/4/2014	$114	10.9%	4/9/2015	$95	NA	NA
South Dakota	Black Hills Power Inc.	D-EL14-026	Electric	3/31/2014	$15	10.3%	3/2/2015	$7	NA	NA
South Dakota	Northern States Power Co. - MN	D-EL14-058	Electric	6/23/2014	$25	10.3%	6/15/2015	$15	NA	NA
Tennessee	Atmos Energy Corp.	D-14-00146	Natural Gas	11/25/201 4	$6	10.7%	5/11/2015	$1	9.8%	-0.9%
Texas	Atmos Energy Corp.	D-GUD-10359 (Mid-Tex Division)	Natural Gas	5/30/2014	$37	NA	7/28/2015	$53	NA	NA
Texas	CenterPoint Energy Resources	D-GUD-10432	Natural Gas	3/27/2015	$7	10.3%	8/25/2015	$5	NA	NA
Texas	Cross Texas Transmission	D-43950	Electric	12/23/201 4	$33	10.6%	5/1/2015	$31	9.6%	-1.0%
Texas	Entergy Texas Inc.	D-44704	Electric	6/12/2015	$76	10.2%	7/20/2015	NA	NA	NA
Virginia	Columbia Gas of Virginia Inc	C-PUE-2014-00020	Natural Gas	4/30/2014	$32	10.9%	8/21/2015	$25	9.8%	-1.2%
Virginia	Virginia Electric & Power Co.	C-PUE-2014-00103 (Rider BW)	Electric	10/31/201 4	$61	11.0%	4/21/2015	$61	11.0%	0.0%
Virginia	Virginia Electric & Power Co.	C-PUE-2014-00050 (Rider B)	Electric	6/16/2014	($2)	12.0%	3/12/2015	($6)	12.0%	0.0%
Virginia	Virginia Electric & Power Co.	C-PUE-2014-00052 (Rider R)	Electric	6/16/2014	$14	11.0%	3/12/2015	$11	11.0%	0.0%
Virginia	Virginia Electric & Power Co.	C-PUE-2014-00051 (Rider S)	Electric	6/16/2014	$6	11.0%	3/12/2015	$6	11.0%	0.0%
Virginia	Virginia Electric & Power Co.	C-PUE-2014-00042 (Rider W)	Electric	5/30/2014	$37	11.0%	2/18/2015	$37	11.0%	0.0%
Washington	PacifiCorp	D-UE-140762	Electric	5/1/2014	$30	10.0%	3/25/2015	$10	9.5%	-0.5%
West Virginia	Appalachian Power Co.	C-14-1152-E-42T	Electric	6/30/2014	$226	10.6%	5/26/2015	$124	9.8%	-0.9%
West Virginia	Monongahela Power Co.	C-14-0702-E-42T	Electric	4/30/2014	$213	11.0%	2/4/2015	$124	NA	NA
Wyoming	PacifiCorp	D-20000-446-ER-14	Electric	3/3/2014	$33	10.0%	1/23/2015	$20	9.5%	-0.5%

Source: SNL Energy, Goldman Sachs Global Investment Research

Exhibit 6: While the recent national allowed RoE levels remain near 10%, a few states including Virginia and Georgia maintain above-average returns
Average authorized RoEs by state in recent rate case rulings



Note: For states without recent rate cases, we include the average of last approved RoEs
Source: SNL Energy, Goldman Sachs Global Investment Research

Rating and pricing information

Ameren Corp. (N/N, $40.80), American Electric Power (N/N, $55.02), American Water Works (N/N, $53.90), Calpine Corp. (B/A, $14.66), Centerpoint Energy Inc. (N/N, $17.75), Cleco Corp. (NR, $53.40), Consolidated Edison Inc. (N/N, $65.53), Dominion Resources Inc. (N/N, $69.22), Duke Energy Corp. (N/N, $69.09), Dynegy Inc. (B/A, $20.52), Edison International (B/N, $61.08), Entergy Corp. (S/N, $63.54), Eversource Energy (N/N, $47.72), Exelon Corp. (NR, $29.02), FirstEnergy Corp. (S/N, $30.47), Great Plains Energy Inc. (B/N, $25.76), NextEra Energy Inc. (B/N, $96.98), NextEra Energy Partners (N/A, $22.54), NRG Energy Inc. (N/A, $15.43), NRG Yield Inc. (B/A, $13.55), PG&E Corp. (N/N, $52.00), Pinnacle West Capital Corp. (N/N, $62.23), Portland General Electric Co. (N/N, $35.70), PPL Corp. (B/N, $31.08), Public Service Enterprise Group (N/N, $39.94), SCANA Corp. (S/N, $52.76), Sempra Energy (B/N, $92.11), Southern Co. (NR, $42.95), WEC Energy Group Inc. (B/N, $49.48) and Westar Energy Inc. (N/N, $37.31)

Disclosure Appendix

Reg AC

We, Michael Lapides, David Fishman and Dylan Campbell, hereby certify that all of the views expressed in this report accurately reflect our personal views about the subject company or companies and its or their securities. We also certify that no part of our compensation was, is or will be, directly or indirectly, related to the specific recommendations or views expressed in this report.

Unless otherwise stated, the individuals listed on the cover page of this report are analysts in Goldman Sachs' Global Investment Research division.

Investment Profile

The Goldman Sachs Investment Profile provides investment context for a security by comparing key attributes of that security to its peer group and market. The four key attributes depicted are: growth, returns, multiple and volatility. Growth, returns and multiple are indexed based on composites of several methodologies to determine the stocks percentile ranking within the region's coverage universe.

The precise calculation of each metric may vary depending on the fiscal year, industry and region but the standard approach is as follows:

Growth is a composite of next year's estimate over current year's estimate, e.g. EPS, EBITDA, Revenue. **Return** is a year one prospective aggregate of various return on capital measures, e.g. CROCI, ROACE, and ROE. **Multiple** is a composite of one-year forward valuation ratios, e.g. P/E, dividend yield, EV/FCF, EV/EBITDA, EV/DACF, Price/Book. **Volatility** is measured as trailing twelve-month volatility adjusted for dividends.

Quantum

Quantum is Goldman Sachs' proprietary database providing access to detailed financial statement histories, forecasts and ratios. It can be used for in-depth analysis of a single company, or to make comparisons between companies in different sectors and markets.

GS SUSTAIN

GS SUSTAIN is a global investment strategy aimed at long-term, long-only performance with a low turnover of ideas. The GS SUSTAIN focus list includes leaders our analysis shows to be well positioned to deliver long term outperformance through sustained competitive advantage and superior returns on capital relative to their global industry peers. Leaders are identified based on quantifiable analysis of three aspects of corporate performance: cash return on cash invested, industry positioning and management quality (the effectiveness of companies' management of the environmental, social and governance issues facing their industry).

Disclosures

Coverage group(s) of stocks by primary analyst(s)

Michael Lapides: America-Diversified Utilities, America-Independent Power Producers, America-Regulated Utilities.

America-Diversified Utilities: Ameren Corp., Centerpoint Energy Inc., Dominion Resources Inc., Edison International, Entergy Corp., Exelon Corp., FirstEnergy Corp., NextEra Energy Inc., PPL Corp., Public Service Enterprise Group, Sempra Energy.

America-Independent Power Producers: Calpine Corp., Dynegy Inc., NextEra Energy Partners, NRG Energy Inc., NRG Yield Inc..

America-Regulated Utilities: American Electric Power, American Water Works, Cleco Corp., Consolidated Edison Inc., Duke Energy Corp., Eversource Energy, Great Plains Energy Inc., PG&E Corp., Pinnacle West Capital Corp., Portland General Electric Co., SCANA Corp., Southern Co., WEC Energy Group Inc., Westar Energy Inc..

Company-specific regulatory disclosures

The following disclosures relate to relationships between The Goldman Sachs Group, Inc. (with its affiliates, "Goldman Sachs") and companies covered by the Global Investment Research Division of Goldman Sachs and referred to in this research.

Goldman Sachs has received compensation for investment banking services in the past 12 months: American Electric Power ($55.99), FirstEnergy Corp. ($31.04) and Southern Co. ($44.13)

Goldman Sachs expects to receive or intends to seek compensation for investment banking services in the next 3 months: American Electric Power ($55.99), FirstEnergy Corp. ($31.04) and Southern Co. ($44.13)

Goldman Sachs has received compensation for non-investment banking services during the past 12 months: American Electric Power ($55.99)

Goldman Sachs had an investment banking services client relationship during the past 12 months with: American Electric Power ($55.99), FirstEnergy Corp. ($31.04) and Southern Co. ($44.13)

Goldman Sachs had a non-investment banking securities-related services client relationship during the past 12 months with: American Electric Power ($55.99), Edison International ($62.33), FirstEnergy Corp. ($31.04) and Southern Co. ($44.13)

Goldman Sachs had a non-securities services client relationship during the past 12 months with: American Electric Power ($55.99), Edison International ($62.33), FirstEnergy Corp. ($31.04) and Southern Co. ($44.13)

Goldman Sachs makes a market in the securities or derivatives thereof: American Electric Power ($55.99), Edison International ($62.33), FirstEnergy Corp. ($31.04) and Southern Co. ($44.13)

Goldman Sachs is a specialist in the relevant securities and will at any given time have an inventory position, "long" or "short," and may be on the opposite side of orders executed on the relevant exchange: Edison International ($62.33)

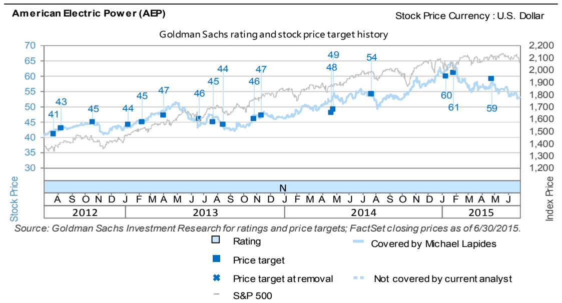
Distribution of ratings/investment banking relationships

Goldman Sachs Investment Research global coverage universe

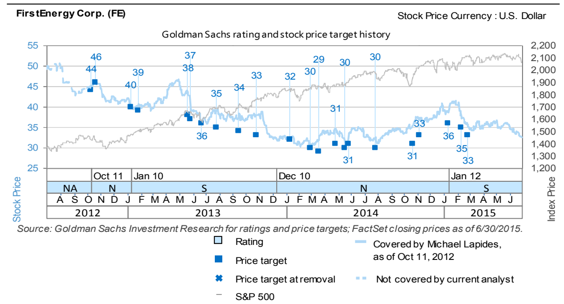
	Rating Distribution			Investment Banking Relationships		
	Buy	Hold	Sell	Buy	Hold	Sell
Global	32%	53%	15%	46%	38%	33%

As of July 1, 2015, Goldman Sachs Global Investment Research had investment ratings on 3,248 equity securities. Goldman Sachs assigns stocks as Buys and Sells on various regional Investment Lists; stocks not so assigned are deemed Neutral. Such assignments equate to Buy, Hold and Sell for the purposes of the above disclosure required by NASD/NYSE rules. See 'Ratings, Coverage groups and views and related definitions' below.

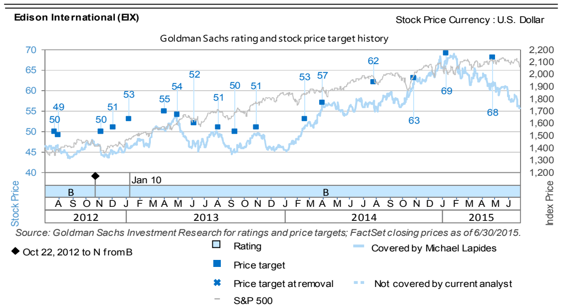
Price target and rating history chart(s)



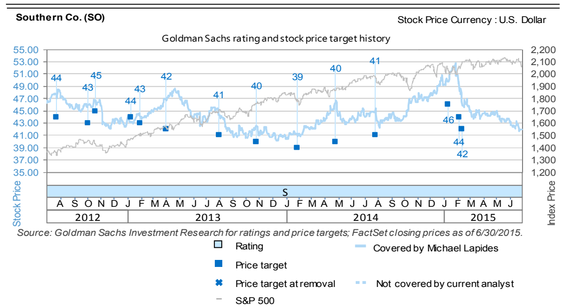
The price targets shown should be considered in the context of all prior published Goldman Sachs research, which may or may not have included price targets, as well as developments relating to the company, its industry and financial markets.



The price targets shown should be considered in the context of all prior published Goldman Sachs research, which may or may not have included price targets, as well as developments relating to the company, its industry and financial markets.



The price targets shown should be considered in the context of all prior published Goldman Sachs research, which may or may not have included price targets, as well as developments relating to the company, its industry and financial markets.



The price targets shown should be considered in the context of all prior published Goldman Sachs research, which may or may not have included price targets, as well as developments relating to the company, its industry and financial markets.

Regulatory disclosures

Disclosures required by United States laws and regulations

See company-specific regulatory disclosures above for any of the following disclosures required as to companies referred to in this report: manager or co-manager in a pending transaction; 1% or other ownership; compensation for certain services; types of client relationships; managed/co-managed public offerings in prior periods; directorships; for equity securities, market making and/or specialist role. Goldman Sachs usually makes a market in fixed income securities of issuers discussed in this report and usually deals as a principal in these securities.

The following are additional required disclosures: **Ownership and material conflicts of interest:** Goldman Sachs policy prohibits its analysts, professionals reporting to analysts and members of their households from owning securities of any company in the analyst's area of coverage. **Analyst compensation:** Analysts are paid in part based on the profitability of Goldman Sachs, which includes investment banking revenues. **Analyst as officer or director:** Goldman Sachs policy prohibits its analysts, persons reporting to analysts or members of their households from serving as an officer, director, advisory board member or employee of any company in the analyst's area of coverage. **Non-U.S. Analysts:** Non-U.S. analysts may not be associated persons of Goldman, Sachs & Co. and therefore may not be subject to NASD Rule 2711/NYSE Rules 472 restrictions on communications with subject company, public appearances and trading securities held by the analysts.

Distribution of ratings: See the distribution of ratings disclosure above. **Price chart:** See the price chart, with changes of ratings and price targets in prior periods, above, or, if electronic format or if with respect to multiple companies which are the subject of this report, on the Goldman Sachs website at http://www.gs.com/research/hedge.html.

Additional disclosures required under the laws and regulations of jurisdictions other than the United States

The following disclosures are those required by the jurisdiction indicated, except to the extent already made above pursuant to United States laws and regulations. **Australia:** Goldman Sachs Australia Pty Ltd and its affiliates are not authorised deposit-taking institutions (as that term is defined in the Banking Act 1959 (Cth)) in Australia and do not provide banking services, nor carry on a banking business, in Australia. This research, and any access to it, is intended only for "wholesale clients" within the meaning of the Australian Corporations Act, unless otherwise agreed by Goldman Sachs. In producing research reports, members of the Global Investment Research Division of Goldman Sachs Australia may attend site visits and other meetings hosted by the issuers the subject of its research reports. In some instances the costs of such site visits or meetings may be met in part or in whole by the issuers concerned if Goldman Sachs Australia considers it is appropriate and reasonable in the specific circumstances relating to the site visit or meeting. **Brazil:** Disclosure information in relation to CVM Instruction 483 is available at http://www.gs.com/worldwide/brazil/area/gir/index.html. Where applicable, the Brazil-registered analyst primarily responsible for the content of this research report, as defined in Article 16 of CVM Instruction 483, is the first author named at the beginning of this report, unless indicated otherwise at the end of the text. **Canada:** Goldman Sachs Canada Inc. is an affiliate of The Goldman Sachs Group Inc. and therefore is included in the company specific disclosures relating to Goldman Sachs (as defined above). Goldman Sachs Canada Inc. has approved of, and agreed to take responsibility for, this research report in Canada if and to the extent that Goldman Sachs Canada Inc. disseminates this research report to its clients. **Hong Kong:** Further information on the securities of covered companies referred to in this research may be obtained on request from Goldman Sachs (Asia) L.L.C. **India:** Further information on the subject company or companies referred to in this research may be obtained from Goldman Sachs (India) Securities Private Limited. Goldman Sachs may beneficially own 1% or more of the securities (as such term is defined in clause 2 (h) the Indian Securities Contracts (Regulation) Act, 1956) of the subject company or companies referred to in this research report. **Japan:** See below. **Korea:** Further information on the subject company or companies referred to in this research may be obtained from Goldman Sachs (Asia) L.L.C., Seoul Branch. **New Zealand:** Goldman Sachs New Zealand Limited and its affiliates are neither "registered banks" nor "deposit takers" (as defined in the Reserve Bank of New Zealand Act 1989) in New Zealand. This research, and any access to it, is intended for "wholesale clients" (as defined in the Financial Advisers Act 2008) unless otherwise agreed by Goldman Sachs. **Russia:** Research reports distributed in the Russian Federation are not advertising as defined in the Russian legislation, but are information and analysis not having product promotion as their main purpose and do not provide appraisal within the meaning of the Russian legislation on appraisal activity. **Singapore:** Further information on the covered companies referred to in this research may be obtained from Goldman Sachs (Singapore) Pte. (Company Number: 198602165W). **Taiwan:** This material is for reference only and must not be reprinted without permission. Investors should carefully consider their own investment risk. Investment results are the responsibility of the individual investor. **United Kingdom:** Persons who would be categorized as retail clients in the United Kingdom, as such term is defined in the rules of the Financial Conduct Authority, should read this research in conjunction with prior Goldman Sachs research on the covered companies referred to herein and should refer to the risk warnings that have been sent to them by Goldman Sachs International. A copy of these risks warnings, and a glossary of certain financial terms used in this report, are available from Goldman Sachs International on request.

European Union: Disclosure information in relation to Article 4 (1) (d) and Article 6 (2) of the European Commission Directive 2003/126/EC is available at http://www.gs.com/disclosures/europeanpolicy.html which states the European Policy for Managing Conflicts of Interest in Connection with Investment Research.

Japan: Goldman Sachs Japan Co., Ltd. is a Financial Instrument Dealer registered with the Kanto Financial Bureau under registration number Kinsho 69, and a member of Japan Securities Dealers Association, Financial Futures Association of Japan and Type II Financial Instruments Firms Association. Sales and purchase of equities are subject to commission pre-determined with clients plus consumption tax. See company-specific disclosures as to any applicable disclosures required by Japanese stock exchanges, the Japanese Securities Dealers Association or the Japanese Securities Finance Company.

Ratings, coverage groups and views and related definitions

Buy (B), Neutral (N), Sell (S) -Analysts recommend stocks as Buys or Sells for inclusion on various regional Investment Lists. Being assigned a Buy or Sell on an Investment List is determined by a stock's return potential relative to its coverage group as described below. Any stock not assigned as a Buy or a Sell on an Investment List is deemed Neutral. Each regional Investment Review Committee manages various regional Investment Lists to a global guideline of 25%-35% of stocks as Buy and 10%-15% of stocks as Sell; however, the distribution of Buys and Sells in any particular coverage group may vary as determined by the regional Investment Review Committee. Regional Conviction Buy and Sell lists represent investment recommendations focused on either the size of the potential return or the likelihood of the realization of the return.

Return potential represents the price differential between the current share price and the price target expected during the time horizon associated with the price target. Price targets are required for all covered stocks. The return potential, price target and associated time horizon are stated in each report adding or reiterating an Investment List membership.

Coverage groups and views: A list of all stocks in each coverage group is available by primary analyst, stock and coverage group at http://www.gs.com/research/hedge.html. The analyst assigns one of the following coverage views which represents the analyst's investment outlook on the coverage group relative to the group's historical fundamentals and/or valuation. **Attractive (A).** The investment outlook over the following 12 months is favorable relative to the coverage group's historical fundamentals and/or valuation. **Neutral (N).** The investment outlook over the following 12 months is neutral relative to the coverage group's historical fundamentals and/or valuation. **Cautious (C).** The investment outlook over the following 12 months is unfavorable relative to the coverage group's historical fundamentals and/or valuation.

Not Rated (NR). The investment rating and target price have been removed pursuant to Goldman Sachs policy when Goldman Sachs is acting in an advisory capacity in a merger or strategic transaction involving this company and in certain other circumstances. **Rating Suspended (RS).** Goldman Sachs Research has suspended the investment rating and price target for this stock, because there is not a sufficient fundamental basis for determining, or there are legal, regulatory or policy constraints around publishing, an investment rating or target. The previous investment rating and price target, if any, are no longer in effect for this stock and should not be relied upon. **Coverage Suspended (CS).** Goldman Sachs has suspended coverage of this company. **Not Covered (NC).** Goldman Sachs does not cover this company. **Not Available or Not Applicable (NA).** The information is not available for display or is not applicable. **Not Meaningful (NM).** The information is not meaningful and is therefore excluded.

Global product; distributing entities

The Global Investment Research Division of Goldman Sachs produces and distributes research products for clients of Goldman Sachs on a global basis. Analysts based in Goldman Sachs offices around the world produce equity research on industries and companies, and research on macroeconomics, currencies, commodities and portfolio strategy. This research is disseminated in Australia by Goldman Sachs Australia Pty Ltd (ABN 21 006 797 897); in Brazil by Goldman Sachs do Brasil Corretora de Títulos e Valores Mobiliários S.A.; in Canada by either Goldman Sachs Canada Inc. or Goldman, Sachs & Co.; in Hong Kong by Goldman Sachs (Asia) L.L.C.; in India by Goldman Sachs (India) Securities Private Ltd.; in Japan by Goldman Sachs Japan Co., Ltd.; in the Republic of Korea by Goldman Sachs (Asia) L.L.C., Seoul Branch; in New Zealand by Goldman Sachs New Zealand Limited; in Russia by OOO Goldman Sachs; in Singapore by Goldman Sachs (Singapore) Pte. (Company Number: 198602165W); and in the United States of America by Goldman, Sachs & Co. Goldman Sachs International has approved this research in connection with its distribution in the United Kingdom and European Union.

European Union: Goldman Sachs International authorised by the Prudential Regulation Authority and regulated by the Financial Conduct Authority and the Prudential Regulation Authority, has approved this research in connection with its distribution in the European Union and United Kingdom; Goldman Sachs AG and Goldman Sachs International Zweigniederlassung Frankfurt, regulated by the Bundesanstalt für Finanzdienstleistungsaufsicht, may also distribute research in Germany.

General disclosures

This research is for our clients only. Other than disclosures relating to Goldman Sachs, this research is based on current public information that we consider reliable, but we do not represent it is accurate or complete, and it should not be relied on as such. We seek to update our research as appropriate, but various regulations may prevent us from doing so. Other than certain industry reports published on a periodic basis, the large majority of reports are published at irregular intervals as appropriate in the analyst's judgment.

Goldman Sachs conducts a global full-service, integrated investment banking, investment management, and brokerage business. We have investment banking and other business relationships with a substantial percentage of the companies covered by our Global Investment Research Division. Goldman, Sachs & Co., the United States broker dealer, is a member of SIPC (http://www.sipc.org).

Our salespeople, traders, and other professionals may provide oral or written market commentary or trading strategies to our clients and principal trading desks that reflect opinions that are contrary to the opinions expressed in this research. Our asset management area, principal trading desks and investing businesses may make investment decisions that are inconsistent with the recommendations or views expressed in this research.

The analysts named in this report may have from time to time discussed with our clients, including Goldman Sachs salespersons and traders, or may discuss in this report, trading strategies that reference catalysts or events that may have a near-term impact on the market price of the equity securities discussed in this report, which impact may be directionally counter to the analyst's published price target expectations for such stocks. Any such trading strategies are distinct from and do not affect the analyst's fundamental equity rating for such stocks, which rating reflects a stock's return potential relative to its coverage group as described herein.

We and our affiliates, officers, directors, and employees, excluding equity and credit analysts, will from time to time have long or short positions in, act as principal in, and buy or sell, the securities or derivatives, if any, referred to in this research.

The views attributed to third party presenters at Goldman Sachs arranged conferences, including individuals from other parts of Goldman Sachs, do not necessarily reflect those of Global Investment Research and are not an official view of Goldman Sachs.

Any third party referenced herein, including any salespeople, traders and other professionals or members of their household, may have positions in the products mentioned that are inconsistent with the views expressed by analysts named in this report.

This research is not an offer to sell or the solicitation of an offer to buy any security in any jurisdiction where such an offer or solicitation would be illegal. It does not constitute a personal recommendation or take into account the particular investment objectives, financial situations, or needs of individual clients. Clients should consider whether any advice or recommendation in this research is suitable for their particular circumstances and, if appropriate, seek professional advice, including tax advice. The price and value of investments referred to in this research and the income from them may fluctuate. Past performance is not a guide to future performance, future returns are not guaranteed, and a loss of original capital may occur. Fluctuations in exchange rates could have adverse effects on the value or price of, or income derived from, certain investments.

Certain transactions, including those involving futures, options, and other derivatives, give rise to substantial risk and are not suitable for all investors. Investors should review current options disclosure documents which are available from Goldman Sachs sales representatives or at http://www.theocc.com/about/publications/character-risks.jsp. Transaction costs may be significant in option strategies calling for multiple purchase and sales of options such as spreads. Supporting documentation will be supplied upon request.

All research reports are disseminated and available to all clients simultaneously through electronic publication to our internal client websites. Not all research content is redistributed to our clients or available to third-party aggregators, nor is Goldman Sachs responsible for the redistribution of our research by third party aggregators. For research, models or other data available on a particular security, please contact your sales representative or go to http://360.gs.com.

Disclosure information is also available at http://www.gs.com/research/hedge.html or from Research Compliance, 200 West Street, New York, NY 10282.