

Board Staff Interrogatory #10

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Ref: Exh C1-1-1, Chart 1

Chart 1, from page 1 of Exh C1-1-1, is replicated below.

Rate Base	2017	2018	2019	2020	2021
Hydro (\$B) ¹	7.5	7.5	7.5	7.6	7.7
Nuclear (\$B) ²	3.3	3.5	3.5	7.5	8.0
Total (\$B)	10.8	11.0	10.9	15.1	15.6
Nuclear Proportion	31%	32%	32%	50%	51%

1. Reflects OPG's 2016-2018 Business Plan, which includes a projection for 2019-2021 (Ex. A2-2-1 Attachment 1).

2. From Ex. I1-1-1, Table 1, sum of line 5, line 6 and line 7. Nuclear amounts do not include the lesser of unamortized asset retirement costs ("ARC") or unfunded nuclear liabilities ("UNL"). This is consistent with the OEB-approved methodology for determining rate base financed by capital structure, wherein the weighted average cost of capital is applied to OPG's rate base that does not include the lesser of ARC or UNL.

a) Please confirm whether the rate base values shown are: i) beginning of year; ii) mid-year or average of the year; or iii) end-of year.

b) OPG proposes that the equity thickness for the combined hydroelectric and nuclear generating regulated assets be increased to 49% for the whole period of the five-year term, in light of increased risk. The significant capital additions are mainly due to the Darlington Refurbishment Program, which significantly increases the relative percentage of OPG's regulated asset rate base related to nuclear generation. However, from Chart 1, significant additions to the nuclear rate base only begin to occur in 2020, when the nuclear rate base becomes approximately equal to the hydroelectric rate base, and exceeds it only in the last year of the plan 2021. For the first three years of the plan (2017-19), regulated hydroelectric rate base remains more than double the nuclear rate base.

Please explain why OPG is proposing that the 49% equity thickness apply to all years in the five-year plan. On an assumption that there could be increased risk due to the increased risk from significant nuclear capital investments, why wouldn't the increased thickness only apply, if necessary, beginning in 2020 or 2021?

Response

a) The rate base values in Chart 1, from page 1 of Ex. C1-1-1 Attachment 1, are determined using a mid-year average methodology. As discussed at Ex. B1-1-1 page 4: “for large in-service additions or adjustments, where the in-service addition amount of the amount of an adjustment exceeds \$50M, the month in which the addition or adjustment is reflected is used, instead of a mid-year average, to improve accuracy.”

b) The following response was prepared by Concentric Energy Advisors:

OPG is proposing that the 49% equity thickness apply to all years in the five-year plan for several reasons. As discussed in Concentric’s Common Equity Ratio Report (Ex. C1-1-1 Attachment 1, pages 13 and 14) the cost of capital (including the capital structure) is a forward-looking concept from the perspective of investors. OPG requires ongoing access to capital on reasonable terms in order to finance the Company’s significant capital spending program over the 2017 to 2021 period and beyond. Investors and credit rating agencies are aware of OPG’s elevated capital spending program and shifting rate base between 2017 and 2021. In order to ensure investors and rating agencies that there is regulatory support for cost recovery and credit quality, OPG’s rates should reflect the increased risk profile of its elevated capital spending program and its shifting rate base to a higher percentage of nuclear assets relative to hydroelectric assets.

Although the first refurbished Darlington unit will not be brought into service until late in the test period, OPG will be making substantial capital investments over the next five years that will require access to capital on reasonable terms and that will place pressure on OPG’s cash flows and credit metrics during this period. In particular, OPG forecasts total capital expenditures of approximately \$5.25 billion on the DRP from 2017-2021 (Ex. D2-2-10, Table 1). DBRS has commented specifically on the risk associated with the DRP as follows:

DBRS believes that given the complexity and scale of the Darlington Refurbishment, there is significant execution risk as well as the potential for cost overruns. The high capital expenditures (capex) required, albeit spread over a ten-year period, in addition to ongoing maintenance capex (total capex forecast of approximately \$2 billion in 2016), are expected to pressure OPG’s key credit metrics.¹

DBRS also notes that OPG is expected to generate a free cash flow deficit in 2016 due to the large capital expenditure program.²

Credit rating agencies have also commented more generally about the credit risk associated with large capital spending programs. For example, DBRS writes:

¹ Ex. A2-3-1, Attachment 1, at 1

² *Ibid.*

1 *For utilities undergoing significant multi-year capital expansion programs, capital*
2 *spending may be considered a primary rating factor. This would be particularly*
3 *relevant for companies with significant nuclear generation development.*³
4

5 Moody's has commented on the credit risk associated with capital spending plans:
6

7 *Given the long-term nature of utility assets and the often lumpy nature of their*
8 *capital expenditures, it is important to analyze both a utility's historical performance*
9 *as well as its prospective future performance, which may be different from*
10 *backward-looking measures. Scores under this factor may be higher or lower than*
11 *what might be expected from historical results, depending on our view of expected*
12 *future performance. In the illustrative mapping examples in this document, the*
13 *scoring grid uses three year averages for the financial strength sub-factors. Multi-*
14 *year periods are usually more representative of credit quality because utilities can*
15 *experience swings in cash flows from one-time events, including items such as*
16 *rate refunds, storm cost deferrals that create a regulatory asset, or securitization*
17 *proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in*
18 *metrics for individual periods, which may influence our view of future performance*
19 *and ratings.*⁴
20

21 In an August 2016 report, S&P explains the importance of regulatory support for large
22 capital projects:

23 *When applicable, a jurisdiction's willingness to support large capital projects with*
24 *cash during construction is an important aspect of our analysis. This is especially*
25 *true when the project represents a major addition to rate base and entails long lead*
26 *times and technological risks that make it susceptible to construction delays.*
27 *Broad support for all capital spending is the most credit-sustaining. Support for*
28 *only specific types of capital spending, such as specific environmental projects or*
29 *system integrity plans, is less so, but still favorable for creditors. Allowance of a*
30 *cash return on construction work-in-progress or similar ratemaking methods*
31 *historically were extraordinary measures for use in unusual circumstances, but*
32 *when construction costs are rising, cash flow support could be crucial to maintain*
33 *credit quality through the spending program. Even more favorable are those*
34 *jurisdictions that present an opportunity for a higher return on capital projects as an*
35 *incentive to investors*⁵.
36

37 The proposed 49% equity thickness for OPG is conservative as compared to the
38 authorized equity ratios for the operating companies held by Concentric's proxy group,

³ DBRS, Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry, October 2015, at 7.

⁴ Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, December 23, 2013, at 22.

⁵ S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

1 none of which is a pure generation company like OPG. As discussed in Ex. C1-1-1
2 Attachment 1, page 32, Moody's views power generation as the highest risk component
3 of the electric utility business, as generation plants are typically the most expensive part
4 of a utility's infrastructure (representing asset concentration risk) and are subject to the
5 greatest risks in both construction and operations, including the risk that incurred costs
6 will either not be recovered in rates or recovered with material delays. In addition,
7 nuclear generation is generally considered to be the highest risk generation source.
8 DBRS explains:

9
10 *Nuclear generation faces higher operating risk than other types of generation*
11 *because of its complex technology (approximately 57% of OPG's production in*
12 *2015). Financial implications of forced outages, especially with older units (e.g.,*
13 *Pickering Nuclear Generating Station), are greater given the high fixed-cost nature*
14 *of these plants as well as the fact that lost revenues from outages are not*
15 *recoverable through rates.*⁶

⁶ Ex. A2-3-1, Attachment 1, at 2

Board Staff Interrogatory #11

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Ref: Exh C1-1-1 Attachment 1, page 36, Figure 6

Concentric's report, at page 36, finds that PNW (Pinnacle West) has slightly less than 20% nuclear, EE (El Paso) has 30% and OPG has 50%. Value Line reports EE's and PNW's nuclear generation as 47% and 27% of nameplate capacity, respectively. To assist with reconciling the generation data shown in Figure 6:

- a) Please provide copies of nuclear industry data from the World Nuclear Association and other sources referenced in your analysis. What specific types of data were used to evaluate business risk associated with the regulated nuclear facilities?
- b) Exactly how does Concentric define generation mix (e.g., nameplate capacity, operating capacity, etc.)?
- c) Please confirm that the generation mix for OPG is measured as forecast for 2017- 2021 and please provide the time periods for which the proxy companies' generation mix was determined.

Response

The following response was prepared by Concentric Energy Advisors:

- a) This response assumes that the interrogatory is requesting additional information relating to Figure 7 of Ex. C1-1-1 Attachment 1: Generation Mix (MW), Percentage Hydro and Nuclear Generation (as opposed to the referenced figure, which is Figure 6). Figure 7 provides OPG's and the proxy group's percentage of regulated hydroelectric and nuclear generation capacity. The data collected to prepare Figure 7 was not provided by the World Nuclear Association. The analysis conducted to produce this figure incorporated data from SNL Financial, an energy industry news and data source that is often relied on by investment analysts and in regulatory proceedings, and OPG's Management Discussion and Analysis. The information requested is provided in Attachment 1, Tables 1 and 2.
- b) For purposes of the analysis presented in Ex. C1-1-1 Attachment 1, Figure 7, Concentric defined generation mix as regulated operating capacity by fuel type. Generation mix data

1 for the proxy group was sourced from SNL Financial,¹ and represents the 2014 sum of
2 operating capacity owned (MW) by fuel type for each company. Generation mix data for
3 OPG represents 2014 in-service generating capacity, and was sourced from OPG's 2014
4 Management's Discussion and Analysis. Please note, the Value Line figures referenced in
5 the interrogatory for EE and PNW are Value Line's reported "generation sources" for those
6 companies. Per a Value Line response to an inquiry by Concentric, "generation sources"
7 represents the proportion of the company's power, including purchased power, coming
8 from different sources, not the nameplate capacity.
9

- 10 c) The generation mix for OPG is not measured as of 2017-2021. The generation mix for
11 OPG and the proxy companies is based on 2014 data.

¹ SNL Financial Template: Power Plant Capacity by Owner Summary.

2014 data		Percentages, Regulated	
		Nuclear	Water
ALLETE, Inc.	ALE	0.00%	6.10%
Ameren Corporation	AEE	11.10%	7.37%
American Electric Power Company, Inc.	AEP	8.21%	3.38%
Duke Energy Corporation	DUK	16.98%	6.62%
Edison International	EIX	20.23%	36.06%
El Paso Electric Company	EE	30.79%	0.00%
Entergy Corporation	ETR	14.65%	0.36%
FirstEnergy Corp.	FE	40.17%	18.06%
Great Plains Energy Inc.	GXP	8.41%	0.00%
IDACORP, Inc.	IDA	0.00%	52.25%
NextEra Energy, Inc.	NEE	12.79%	0.00%
PG&E Corporation	PCG	29.06%	50.46%
Pinnacle West Capital Corporation	PNW	18.43%	0.00%
PNM Resources, Inc.	PNM	16.99%	0.00%
Portland General Electric Company	POR	0.00%	14.25%
Southern Company	SO	10.22%	7.96%
Westar Energy, Inc.	WR	8.98%	0.00%
Xcel Energy Inc.	XEL	9.08%	2.82%
Emera Incorporated	EMA	0.00%	0.00%
Fortis Inc.	FTS	0.00%	0.78%

SNL Capacity Metrics by Owner Template v2

Core Functionality:

This template allows users to look at aggregate plant capacities at the ultimate parent level, with the ability to filter by fuel type, location, etc.

How to use:

- Make sure the Allow Excel Calculation option has been enabled.
- Click the Refresh button to the right, a built-in macro will automatically update the SourceData sheet with current data.¹
- Select criteria in the pivot table below to build reports.²

1. Existing data is based on current ownership, and current operating capacity, as of last spreadsheet refresh.

2. Familiarity with Excel Pivot Tables is a must, in order to fully maximize the use of this spreadsheet. Please consult Microsoft Help section with questions.

State	(All)
NERC Region Code	(All)
RTO	(All)
Regulatory Status	Regulated

Sum of Capacity Owned (MW)	Fuel Type		Percentages, Regulated		
Ultimate Parent	Nuclear	Water	Grand Total	Nuclear	Water
Duke Energy Corporation	9,130	3,560	53,764	17%	7%
Southern Company	3,690	2,876	36,109	10%	8%
NextEra Energy, Inc.	3,514		27,470	13%	0%
American Electric Power Company, Inc.	2,191	902	26,700	8%	3%
Entergy Corporation	3,010	74	20,544	15%	0%
Xcel Energy Inc.	1,673	520	18,429	9%	3%
Ameren Corporation	1,236	821	11,130	11%	7%
FirstEnergy Corp.	3,140	1,411	7,816	40%	18%
PG&E Corporation	2,240	3,890	7,709	29%	50%
Great Plains Energy Inc.	566		6,734	8%	0%
Pinnacle West Capital Corporation	1,165		6,320	18%	0%
Westar Energy, Inc.	566		6,305	9%	0%
IDACORP, Inc.		2,015	3,856	0%	52%
Portland General Electric Company		499	3,504	0%	14%
Edison International	632	1,128	3,127	20%	36%
Fortis Inc.		22	2,889	0%	1%
PNM Resources, Inc.	408		2,403	17%	0%
El Paso Electric Company	632		2,054	31%	0%
ALLETE, Inc.		120	1,964	0%	6%
Emera Incorporated			2	0%	0%

Board Staff Interrogatory #12

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Ref: Exh C1-1-1 Attachment 1, page 15

The evidence describes the potential impact of the proposed nuclear refurbishments on OPG's default risk and other key credit metrics.

- a) Exh C1-1-1 Attachment 1, page 15 states that "[c]redit metrics are expected to be pressured by deferral of revenues to the post-nuclear facility refurbishment period". Please provide any analysis conducted by Concentric, including associated workpapers and models, to evaluate the impacts on credit metrics and/or changes to default risks.
- b) Include all calculations/estimates of key financial ratios (such as FFO Interest Coverage, FFO to Total Debt, Debt to EBITDA) developed/analyzed by Concentric for OPG over the 2017-2021 period.

Response

The following response was provided by Concentric Energy Advisors:

- a) The interrogatory has misquoted Concentric's Common Equity Ratio Report. The report (C1-1-1 Attachment 1, page 15) states that "[c]redit metrics are expected to be further pressured by deferral of some revenues to the post refurbishment period." For the purposes of developing direct evidence, Concentric did not develop a model to calculate forecasted credit metrics or default risks. Concentric reviewed OPG's 2016-2018 Business Plan (Ex. A2-2-1, Attachment 1), which provides information related to OPG's forecasted financing needs, liquidity and credit metrics for the period 2016 to 2021. Concentric also reviewed ratings reports from DBRS and S&P, as discussed in Concentric's Common Equity Ratio Report.
- b) The Financing, Liquidity and Credit Metrics section of the Business Plan (A-2-2-1, Attachment 1, page 17-18), provides OPG's forecasted credit metrics, including the FFO Adjusted Interest Coverage Ratio, the Debt/EBITDA Ratio, and the FFO/Total Debt Ratio.

Board Staff Interrogatory #13

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Ref: Exh C1-1-1 Attachment 1, page 18

OPG is transitioning to an incentive rate plan for hydroelectric generation.

Please provide any analysis performed or relied upon by Concentric in evaluating changes in regulatory risk exposure to OPG's hydroelectric facilities as a result of transitioning to the five-year incentive rate plan. If an analysis was conducted, please include associated workpapers.

Response

The following response was provided by Concentric Energy Advisors:

Concentric conducted a qualitative assessment of the change in risk associated with the transition to a five-year incentive rate plan for OPG's hydroelectric facilities. There are no associated work papers; this assessment, however, considered the following factors:

1. *Identification of the change in risk from the prior regulatory framework adopted by the OEB for OPG's prescribed hydroelectric facilities to that proposed for the 2017-2021 plan period.*

Under the prior regulatory framework, OPG submitted cost-of-service projections covering a two year test period (e.g., January 1, 2014 through December 31, 2015 in EB-2013-0321). That practice was also followed in OPG's prior two rate applications (EB-2007-0905 and EB-2010-0008). As described by the Board, the ratemaking approach was straightforward:

At the highest level, OPG's payment amounts result from a simple equation: OPG's reasonably incurred costs divided by the number of megawatt-hours it is expected to produce (i.e. the production forecast).¹

Under the proposed rate plan, a key element will be the deliberate decoupling of the payment amounts OPG receives from the costs of its hydroelectric facilities for a five year period. This will be accomplished through a comprehensive I-X price cap (including

¹ EB-2013-0321, at 8.

capital and O&M) for the payment amount. That entails a transfer of risk from customers to OPG for the following reasons:

- Under I-X, the likelihood that actual costs will differ from revenues is increased as compared to a cost of service rate setting framework.
- The rate plan extends to five years from two, increasing the probability that costs and rates will diverge. Even if one considers the historical tendency for OPG to hold rates fixed for a third year following its two-year rate periods, the option to file for the rate increase existed, and it will not in the proposed plan (unless the 300 basis point off-ramp is reached).
- The “going-in” rates are those adopted in EB-2013-0321 (adjusted for tax losses as discussed in Ex. A1-3-2 section 2.3.2), creating in essence an eight year rate plan, with the first two years based on projected cost of service, one fixed, and the remaining five under the I-X price cap.

2. *Credit rating agency assessments of the risks associated with performance based regulatory frameworks.*

Credit rating agencies have identified performance based regulation mechanisms as riskier than cost of service-based rates. As cited in Concentric’s evidence (Exhibit C1-1-1 Attachment 1 at 25), DBRS ranks the regulatory risk of cost of service as “Excellent”, but ranks incentive regulation programs of 4-5 years as “Satisfactory,” two notches lower on its scale. Further, in its April 2016 ratings report on OPG, DBRS stated, “DBRS believes that profitability for OPG could continue to be challenged following a switch to an IR framework, as the introduction of productivity and efficiency targets could further depress earnings.”²

In its assessment of the U.S. regulatory environment, Standard and Poors adopts a similar view of the impacts of incentive regulation on credit quality:

*We typically view jurisdictions as credit-supportive if regulators use symmetrical incentive mechanisms sparingly in the rate-setting process. When incentives play a larger role in the rate-setting approach, but are well-designed to evenly allocate risk, we see less support for credit quality. We regard still lower jurisdictions where incentives dominate and are poorly designed. Jurisdictions where incentives significantly degrade risk and are part of a comprehensive incentive regime harbor the most risk for creditors.*³

These factors, collectively, led to the assessment of increased risk associated with the change to an incentive rate mechanism for the hydroelectric facilities.

² Ex. A2-3-1, Attachment 1, at 1.

³ Assessing U.S. Investor-Owned Utility Regulatory Environments, Standard and Poor’s, August 10, 2016, at 6.

Board Staff Interrogatory #14

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Ref: Exh C1-1-1 Attachment 1, pages 30-41

Concentric's Comparative Analysis, includes an analysis to select the proxy group of companies, and the evaluation of risks discussed under "Risk Analysis".

- a) Please provide electronic copies of Exhibits 1, 2 and 3 referenced in the "Selection of Proxy Companies" and "Risk Analysis" subsections of the report (Pages 30 & 35).
- b) Please provide exhibits showing underlying data and calculations of Capital Expenditures for proxy companies illustrated in "Figure 8: Forecasted Capital Spending/ Net PP&E" of the report (Page 36).

Response

The following response was provided by Concentric Energy Advisors:

- a) Please see Exhibit 1, Exhibit 2, and Exhibit 3 for electronic copies.
- b) Please see Attachments 1 through 7 for the underlying data for Figure 8.

CapEx Spending
Source of US data: Value Line

capital spending per share			common shares outstanding (millions)		
Company	Ticker	2018-2020	Company	Ticker	2018-2020
Emera Inc.*	EMA		Emera Inc.*	EMA	
Fortis Inc.*	FTS		Fortis Inc.*	FTS	
Ameren Corporation	AEE	7.25	Ameren Corporation	AEE	242.63
ALLETE, Inc.	ALE	5.5	ALLETE, Inc.	ALE	50
American Electric Power Company, Inc.	AEP	8.5	American Electric Power Company, Inc.	AEP	500
Duke Energy Corporation	DUK	11.75	Duke Energy Corporation	DUK	692
Edison International	EIX	13.25	Edison International	EIX	325.81
El Paso Electric Company	EE	7.25	El Paso Electric Company	EE	41.1
Entergy Corporation	ETR	16	Entergy Corporation	ETR	178.4
FirstEnergy Corporation	FE	7.75	FirstEnergy Corporation	FE	435
Great Plains Energy Inc.	GXP	3.75	Great Plains Energy Inc.	GXP	155.5
IDACORP, Inc.	IDA	6	IDACORP, Inc.	IDA	50.3
NextEra Energy, Inc.	NEE	16.75	NextEra Energy, Inc.	NEE	475
PG&E Corporation	PCG	11.5	PG&E Corporation	PCG	520
Pinnacle West Capital Corporation	PNW	9.75	Pinnacle West Capital Corporation	PNW	118
PNM Resources, Inc.	PNM	5.5	PNM Resources, Inc.	PNM	80
Portland General Electric Company	POR	3.25	Portland General Electric Company	POR	89.7
Southern Company	SO	6.5	Southern Company	SO	917
Westar Energy, Inc.	WR	7.95	Westar Energy, Inc.	WR	155
Xcel Energy Inc.	XEL	6	Xcel Energy Inc.	XEL	508

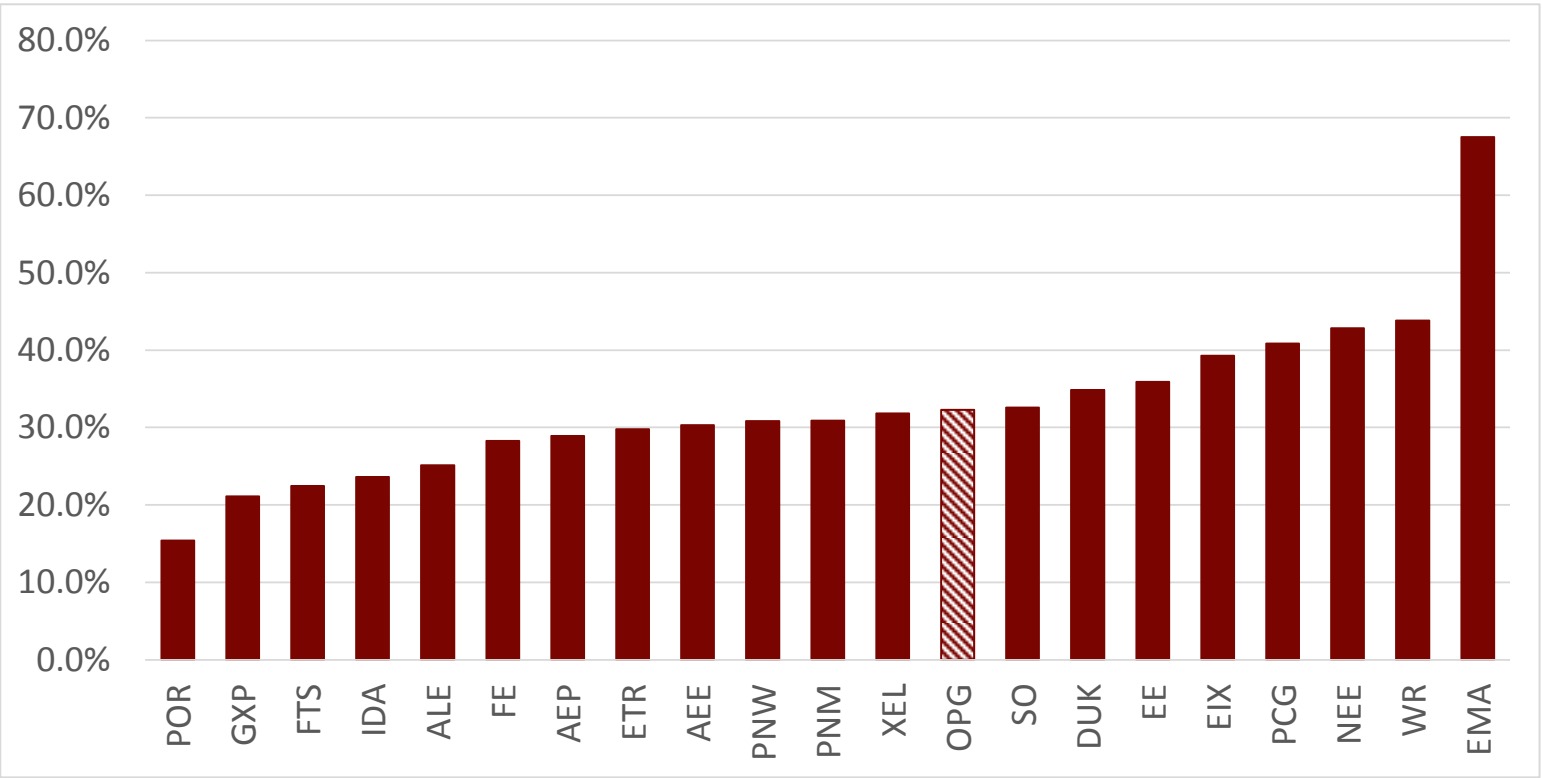
Capital Spending (Calc.)(millions)					Net Plant (\$mill)
Company	Ticker	2018-2020	Value	Line Date	2014
Emera Inc.*	EMA	\$ 3,789 [2]			5,610 [3]
Fortis Inc.*	FTS	\$ 3,846 [1]			17,152 [4]
Ameren Corporation	AEE	\$ 5,277	12/18/2015		17,424
ALLETE, Inc.	ALE	\$ 825	12/18/2015		3,286
American Electric Power Company, Inc.	AEP	\$ 12,750	12/18/2015		44,117
Duke Energy Corporation	DUK	\$ 24,393	11/20/2015		70,046
Edison International	EIX	\$ 12,951	1/29/2016		32,981
El Paso Electric Company	EE	\$ 894	1/29/2016		2,488
Entergy Corporation	ETR	\$ 8,563	12/18/2015		28,723
FirstEnergy Corporation	FE	\$ 10,114	11/20/2015		35,783
Great Plains Energy Inc.	GXP	\$ 1,749	12/18/2015		8,280
IDACORP, Inc.	IDA	\$ 905	1/29/2016		3,834
NextEra Energy, Inc.	NEE	\$ 23,869	11/20/2015		55,705
PG&E Corporation	PCG	\$ 17,940	1/29/2016		43,941
Pinnacle West Capital Corporation	PNW	\$ 3,452	1/29/2016		11,194
PNM Resources, Inc.	PNM	\$ 1,320	1/29/2016		4,270
Portland General Electric Company	POR	\$ 875	1/29/2016		5,679
Southern Company	SO	\$ 17,882	11/20/2015		54,868
Westar Energy, Inc.	WR	\$ 3,697	12/18/2015		8,442
Xcel Energy Inc.	XEL	\$ 9,144	1/29/2016		28,757
Ontario Power Generation Inc.	OPG	\$ 4,487			13,900 [5]

Capital Spending/Net Plant		
Company	Ticker	2018-2020 capex/2014 net plant
Ameren Corporation	AEE	30.3%
ALLETE, Inc.	ALE	25.1%
American Electric Power Company, Inc.	AEP	28.9%
Duke Energy Corporation	DUK	34.8%
Edison International	EIX	39.3%
El Paso Electric Company	EE	35.9%
Entergy Corporation	ETR	29.8%
FirstEnergy Corporation	FE	28.3%
Great Plains Energy Inc.	GXP	21.1%
IDACORP, Inc.	IDA	23.6%
NextEra Energy, Inc.	NEE	42.8%
PG&E Corporation	PCG	40.8%
Pinnacle West Capital Corporation	PNW	30.8%
PNM Resources, Inc.	PNM	30.9%
Portland General Electric Company	POR	15.4%
Southern Company	SO	32.6%
Westar Energy, Inc.	WR	43.8%
Xcel Energy Inc.	XEL	31.8%
Emera Inc.	EMA	67.5%
Fortis Inc.	FTS	22.4%
Ontario Power Generation	OPG	32.3%

Values for Chart, sorted	
	2018-2020 capex/2014 net plant
POR	15.4%
GXP	21.1%
FTS	22.4%
IDA	23.6%
ALE	25.1%
FE	28.3%
AEP	28.9%
ETR	29.8%
AEE	30.3%
PNW	30.8%
PNM	30.9%
XEL	31.8%
OPG	32.3%
SO	32.6%
DUK	34.8%
EE	35.9%
EIX	39.3%
PCG	40.8%
NEE	42.8%
WR	43.8%
EMA	67.5%

Figure 8

2018-2020 capex/2014 net plant



[1] Fortis, Investor Presentation November 10, 2015, p 12

Fortis Capex		
F	2018	1.8
F	2019	1.6
F	2020	1.6
2018-2020 Total		5.000 billion 5000 million US \$ 3,846 million Canadian \$

US dollar denominated CAPEX converted at a USD/CAD exchange rate of 1.30

[2] Emera, Investor Presentation January 20, 2016, p 28

Emera CapEx		
Pro Forma Capital Expenditure Profile[a]		
	(CAD\$ mm)	
2018	1266	
2019	1260	
2020	1263	calc.
2018-2020 Total		3,789 (CAD\$ mm)

[a] Includes debt-financed portion of Maritime Link; FX USD/CAD \$1.3179

- [3] Emera Inc. Consolidated Financial Statements (2014), page 56. Million CAD.
- [4] Fortis 2014 Annual Report, Notes to Consolidated Financial Statements, page 99. Millions.
- [5] OPG’s 2015 MDA financial report, p. 60, 2014 Segment property, plant and equipment, net, regulated



News
from Ontario Power Generation

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March 4, 2016

OPG REPORTS 2015 FINANCIAL RESULTS

Strong operating and financial results position OPG well for the refurbishment of the Darlington station

[Toronto]: – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of \$402 million for 2015, down from \$561 million excluding extraordinary gain in 2014. The decreased earnings were mainly a result of the planned four-unit Vacuum Building Outage (VBO) at the Darlington Nuclear Generating Station (GS) in 2015, which reduced nuclear generation and increased operations, maintenance and administration (OM&A) expenses. The decrease in earnings in 2015 was partially offset by the new base regulated prices effective November 2014 and the newly in-serviced hydroelectric units.

“OPG’s strong operating and financial performance over the last few years allows us to proceed with confidence in refurbishing our nuclear plant at Darlington,” said Jeff Lyash, OPG President and CEO. “Over its additional 30-plus years of operating life, Darlington will provide a reliable supply of clean electricity and is expected to contribute approximately \$50 billion in additional economic benefits to Ontario.” Mr. Lyash also noted, “We currently produce about half of Ontario’s electricity and our power costs customers approximately 40 per cent less than the rest of the market. Undertaking the Darlington Refurbishment project will allow us to keep moderating overall electricity prices for customers for decades to come and contributes to the Province’s climate change goals.”

“I am also pleased to continue our record of partnering with Indigenous communities in 2015 as the construction of the Peter Sutherland Sr. GS is being undertaken in partnership with the Taykwa Tagamou Nation.”

Mr. Lyash added, “In 2015, OPG again achieved a strong safety performance. As one of the company’s fundamental core values, safety is embedded in all that we do. Our goal is zero injuries.”

In January 2016, OPG announced that it is ready to deliver on the Government of Ontario’s decision to proceed with the refurbishment of the first of four units at Darlington and to pursue continued operations at the Pickering Nuclear GS to 2024, pending necessary approvals. Operating Pickering to 2024 will help provide a reliable supply of baseload electricity while the Darlington units and the units operated by Bruce Power L.P. undergo refurbishment.

Since 2010, OPG has invested more than \$200 million in Pickering to ensure its safe and reliable operation. In 2015, the Pickering Station provided about 14 per cent of

Selected Consolidated Balance Sheet Information as at December 31, 2014	Regulated Nuclear Waste Manage- ment			Unregulated Services, Trading, and Other Non- Generation		
<i>(millions of dollars)</i>	Nuclear Generation	Hydro- electric	Contracted Generation Portfolio	Other Non- Generation	Total	
Segment property, plant and equipment in-service, net	4,679	-	7,483	3,267	338	15,767
Segment construction in progress	1,652	-	86	35	53	1,826
Segment property, plant and equipment, net	6,331	-	7,569	3,302	391	17,593
Segment intangible assets in-service, net	11	-	1	4	14	30
Segment development in progress	2	-	1	-	43	46
Segment intangible assets, net	13	-	2	4	57	76
Segment fuel inventory	298	-	-	36	-	334
Segment materials and supplies inventory, net:						
Current	93	-	-	1	-	94
Long-term	332	-	1	5	-	338
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	14,379	-	-	-	14,379
Fixed asset removal and nuclear waste management liabilities	-	(16,663)	-	(154)	(211)	(17,028)

Selected Consolidated Cash Flow Information	Regulated			Unregulated Services, Trading, and Other Non- Generation		
<i>(millions of dollars)</i>	Nuclear Generation	Nuclear Waste Management	Hydro- electric	Contracted Generation Portfolio	Other Non- Generation	Total
Year ended December 31, 2015 Investment in property, plant and equipment, and intangible assets	1,023	-	86	222	45	1,376
Year ended December 31, 2014 Investment in property, plant and equipment, and intangible assets	991	-	84	423	47	1,545

EMERA INCORPORATED

Consolidated

Financial Statements

December 31, 2014 and 2013

In the ordinary course of business, Emera Maine received \$1.1 million from NWP for the year ended December 31, 2014 (2013 – \$0.9 million) for the transportation of electric power over its transmission lines and is measured at the exchange amount.

In 2013, Emera, through a wholly owned subsidiary, had a \$150 million USD loan receivable from a wholly owned subsidiary of NWP, in which Emera holds a 49 per cent interest. This loan was subsequently repaid in November 2013. In the ordinary course of business, Emera earned \$10.7 million for the year ended December 31, 2013, which was recognized in “Interest expense, net” and was measured at the exchange amount.

NSPML

In the ordinary course of business, Emera and NSPI provided NSPML, an investment under significant influence effective Q2 2014, with corporate support and other services. The amount outstanding as at December 31, 2014 was \$3.5 million and is recognized in “Due from related parties” in current assets on Emera’s Consolidated Balance Sheets (December 31, 2013 – nil).

19. OTHER CURRENT ASSETS

Other current assets consisted of the following:

As at millions of Canadian dollars	December 31 2014	December 31 2013
Net investment in direct financing lease	\$ 5.1	\$ 3.1
Dividend receivable	5.0	4.2
Capitalized transportation capacity	70.5	55.2
	\$ 80.6	\$ 62.5

20. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consisted of the following regulated and non-regulated assets:

As at millions of Canadian dollars	December 31 2014	December 31 2013
Generation	\$ 4,415.5	\$ 4,290.3
Transmission	1,331.1	1,215.2
Distribution	2,182.9	2,085.2
General plant and other	722.5	684.3
Total cost	8,652.0	8,275.0
Less: Accumulated depreciation	(3,362.0)	(3,183.1)
	5,290.0	5,091.9
Construction work in progress	320.2	235.8
Net book value	\$ 5,610.2	\$ 5,327.7

For the year ended December 31, 2014, AFUDC of \$12.0 million (2013 – \$14.5 million) was capitalized to “Property, plant and equipment”.

As a result of regulator-approved accounting policies and depreciation rates, NSPI, Emera Maine and GBPC defer certain costs within “Property, plant and equipment” that would not otherwise be deferred in the absence of rate regulation. Cumulative differences between items recognized for rate regulatory purposes and applicable accounting standards including depreciation rates, AFUDC and overhead costs, cannot be separately determined. Cumulative deferred accretion expense related to AROs was \$10.3 million as at December 31, 2014 (2013 – \$12.7 million).



Investor Presentation

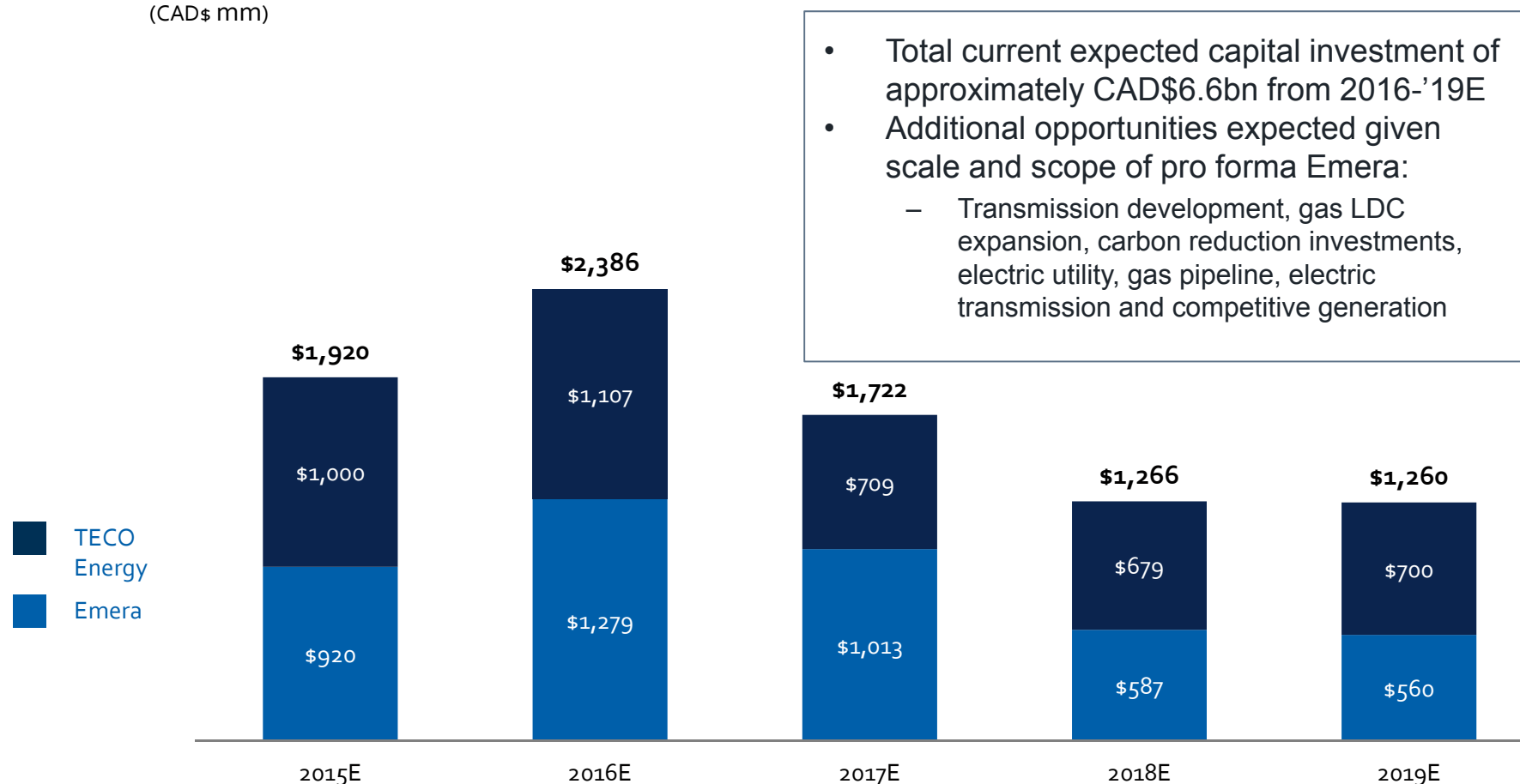
CIBC Annual Whistler
Conference
January 20th, 2016



PRO FORMA \$8.6bn CAPITAL INVESTMENT PLAN TO DRIVE GROWTH

Pro Forma Capital Expenditure Profile¹

(CAD\$ mm)

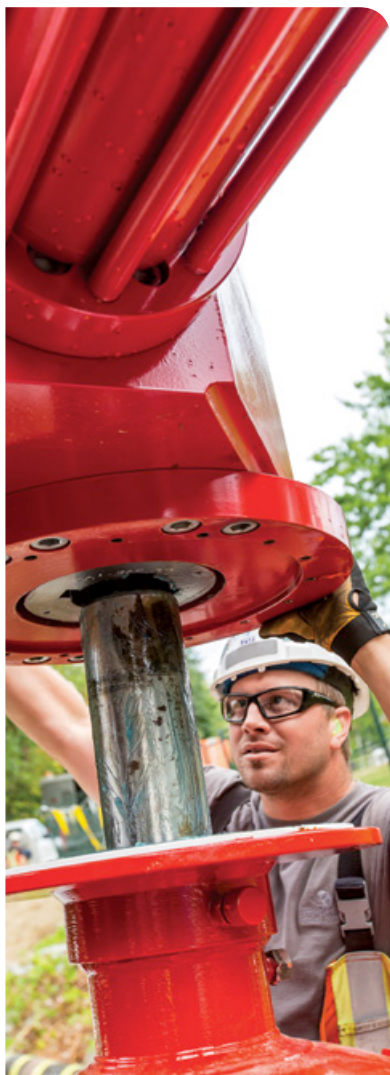


¹ Includes debt-financed portion of Maritime Link; FX USD/CAD \$1.3179



2014 ANNUAL REPORT

Strong. Profitable. Growing.



Notes to Consolidated Financial Statements

9. Utility Capital Assets

2014

<i>(in millions)</i>	Cost	Accumulated Depreciation	Net Book Value
Distribution			
Electric	\$ 8,102	\$ (2,317)	\$ 5,785
Gas	3,475	(920)	2,555
Transmission			
Electric	2,562	(859)	1,703
Gas	1,649	(491)	1,158
Generation	5,296	(2,189)	3,107
Other	2,158	(731)	1,427
Assets under construction	1,250	–	1,250
Land	167	–	167
	\$ 24,659	\$ (7,507)	\$ 17,152

2013

<i>(in millions)</i>	Cost	Accumulated Depreciation	Net Book Value
Distribution			
Electric	\$ 5,716	\$ (1,526)	\$ 4,190
Gas	3,022	(805)	2,217
Transmission			
Electric	1,382	(390)	992
Gas	1,579	(462)	1,117
Generation	1,462	(432)	1,030
Other	1,594	(536)	1,058
Assets under construction	881	–	881
Land	133	–	133
	\$ 15,769	\$ (4,151)	\$ 11,618

Electric distribution assets are those used to distribute electricity at lower voltages (generally below 69 kV). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment. Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kPa) or a hoop stress of less than 20% of standard minimum yield strength. These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment.

Electric transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires, switching equipment, transformers, support structures and other related equipment. Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher) or a hoop stress of 20% or more of standard minimum yield strength. These assets include transmission stations, telemetry, transmission pipe and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, coal-fired generating stations, dams, reservoirs, photovoltaic systems and other related equipment.

Other assets include buildings, equipment, vehicles, inventory and information technology assets.

As at December 31, 2014, assets under construction are primarily associated with the Waneta Expansion and other capital projects at the Corporation's regulated utilities.

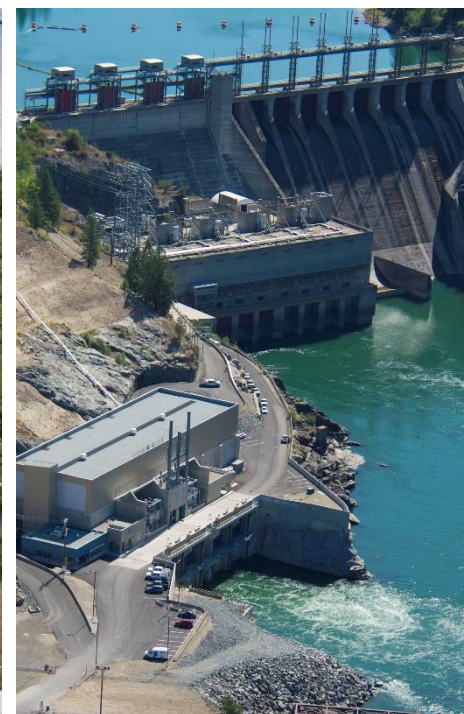
The cost of utility capital assets under capital lease as at December 31, 2014 was \$1,088 million (December 31, 2013 – \$313 million) and related accumulated depreciation was \$627 million (December 31, 2013 – \$70 million). Utility assets under capital lease increased in 2014 due to the acquisition of UNS Energy (Notes 15 and 29).

50th EEI Financial Conference

Hollywood, FL – November 10, 2015



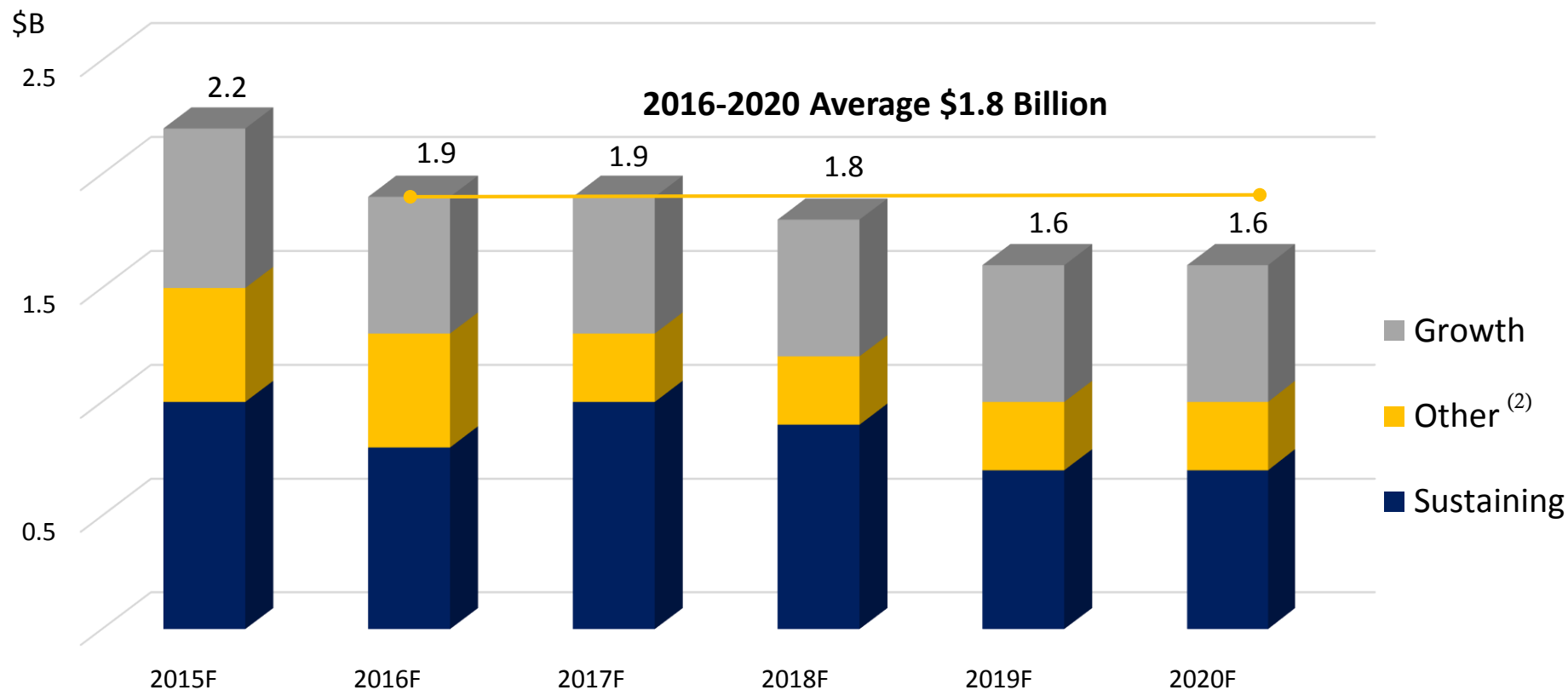
FORTIS



Barry Perry

President & CEO

Capital Program ~ \$9 Billion⁽¹⁾



⁽¹⁾ US dollar denominated CAPEX converted at a USD/CAD exchange rate of 1.30

⁽²⁾ Capital expenditures related to facilities, equipment, vehicles, information technology systems and other assets

AMEREN NYSE-AEE										RECENT PRICE	42.74	P/E RATIO	16.4	Trailing: 17.4 (Median: 15.0)	RELATIVE P/E RATIO	0.93	DIV'D YLD	4.0%	VALUE LINE																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																														
TIMELINESS	3	Raised 11/20/15	High: 50.4	56.8	55.2	55.0	54.3	35.3	29.9	34.1	35.3	37.3	48.1	46.8						Target Price	Range																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																												
SAFETY	2	Raised 6/20/14	Low: 40.6	47.5	48.0	47.1	25.5	19.5	23.1	25.5	28.4	30.6	35.2	37.3						2018	2019	2020																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																											
TECHNICAL	1	Raised 12/11/15	LEGENDS 0.68 x Dividends p sh divided by Interest Rate Relative Price Strength Options: Yes Shaded area indicates recession																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																														

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢; '05, (\$1.84); gain (losses) on disc. ops.: '04, \$2.57, '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next exp. report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. (C) Div'd reinvestment plan avail. 1 Shareholder investment plan avail. (C) Incl. deferred chgs. In '14: \$7.78/sh.	(D) In mill. (E) Rate base: Orig. cost deprec. Rate allowed on com. eq. in '10: 10.38%; earned on avg. com. eq. '14: 8.6%. Reg. Clim.: Avg. (F) Summer peak in '12 & '13.	Company's Financial Strength Stock's Price Stability Price Growth Persistence Earnings Predictability	A 95 35 80
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(A) Diluted EPS. Excl. nonrec. gains (losses): '02, (\$3.86); '03, (\$1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); discount. ops.: '02, (57¢); '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '15, 4¢. '14 EPS don't add due to rounding. Next exs. report due late Jan. (B) Div'ds histor- ical. paid early Mar., June, Sept., & Dec. = Div'd reinvest. plan avail. (C) Incl. intang. In '14: 167.17\$/sh. (D) In mill. (E) Rate base: various. Rates all'd on com. eq.: 9.65%-10.9%; earn. on avg. com. eq. '14: 9.9%. Reg. Clim.: Avg.		Company's Financial Strength A Stock's Price Stability 100 Price Growth Persistence 55 Earnings Predictability 90
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DUKE ENERGY NYSE-DUK				RECENT PRICE	67.37	P/E RATIO	15.0	(Trailing: 16.0 Median: NMF)	RELATIVE P/E RATIO	0.84	DIV'D YLD	5.0%	VALUE LINE																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																											
TIMELINESS	3	Raised 11/13/15		High:	63.9	61.8	53.8	55.8	66.4	71.1	75.5	87.3	90.0		Target Price Range	2018	2019	2020																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																						
SAFETY	2	New 6/1/07		Low:	50.7	40.5	35.2	46.4	50.6	59.6	64.2	67.1	67.1																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																											
TECHNICAL	2	Raised 11/20/15		LEGENDS 0.56 x Dividends p sh divided by Interest Rate Relative Price Strength 1-for-3 Rev split 7/12 Options: Yes Shaded area indicates recession 1-for-3 Reverse % TOT. RETURN 10/15 THIS STOCK VL ARITH.* INDEX 1 yr. -9.4 -1.3 3 yr. 23.9 49.3 5 yr. 64.9 73.5																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																				

(A) Dil. EPS. Excl. nonrec. losses: '12, 70¢; '13, 24¢; '14, 67¢; gains (loss) on disc. ops.: '12, 6¢; '13, 2¢; '14, (80¢); '15, 5¢. '12 & '13 EPS don't add due to chng. in shs. or rounding. (B) Div'ds paid mid-Mar., June, Sept., & Dec. Div'd reinv. plan avail. (C) Incl. intang. In '14: \$38.94/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in '13 in NC/SC: 10.2%; in '09 in OH: 10.63%; in '04 in IN: 10.3%; earned on avg. com. eq., '14: 7.0%. Reg. Climate: NC Avg.; SC, OH, IN Above Avg.

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Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	80

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EDISON INTERNAT'L NYSE-EIX					RECENT PRICE	60.12	P/E RATIO	17.0	(Trailing: 13.8 Median: 12.0)	RELATIVE P/E RATIO	1.04	DIV'D YLD	3.2%	VALUE LINE					
TIMELINESS	3	Lowered 11/7/14	High: 32.5	49.2	47.2	60.3	55.7	36.7	39.4	41.6	48.0	54.2	68.7	69.6		Target Price Range			
SAFETY	2	Raised 5/3/13	Low: 21.2	30.4	37.9	42.8	26.7	23.1	30.4	32.6	39.6	44.3	44.7	55.2		2018 2019 2020			
TECHNICAL	3	Lowered 1/1/16	LEGENDS 1.16 x Dividends p sh divided by Interest Rate Relative Price Strength Options: Yes Shaded area indicates recession												120				
BETA	.70	(1.00 = Market)													100				
2018-20 PROJECTIONS																			
Price	80	Gain (+35%)	Ann'l Total Return																
Low	60	(Nil)	10% 4%																
Insider Decisions																			
M A M J J A S O N	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
to Buy	2	0	1	0	0	0	1	0	1	0	1	0	1	0	1				
Options	2	0	1	0	0	0	1	0	1	0	1	0	1	0	1				
to Sell	2	0	1	0	0	0	1	0	1	0	1	0	1	0	1				
Institutional Decisions																			
1Q2015	248	226	242	218	218	218	218	218	218	218	218	218	218	218	218				
to Buy	248	226	242	218	218	218	218	218	218	218	218	218	218	218	218				
to Sell	216	228	218	218	218	218	218	218	218	218	218	218	218	218	218				
Hld's(000)	263836	266122	268851	268851	268851	268851	268851	268851	268851	268851	268851	268851	268851	268851	268851				
Percent shares traded																			
1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC 18-20	
27.85	35.96	35.10	35.26	37.25	31.30	36.38	38.74	40.25	43.31	37.98	38.09	39.16	36.41	38.61	41.17	37.45	39.60	Revenues per sh	46.00
7.20	d.52	4.35	4.79	5.88	3.79	6.99	7.25	7.60	8.08	7.96	8.41	9.03	9.63	8.80	9.95	10.10	10.70	"Cash Flow" per sh	13.00
2.03	d5.84	1.30	1.82	2.38	.69	3.34	3.28	3.32	3.68	3.24	3.35	3.23	4.55	3.78	4.33	3.80	4.10	Earnings per sh ^A	5.25
1.08	.83	--	--	--	.80	1.02	1.10	1.18	1.23	1.25	1.27	1.29	1.31	1.37	1.48	1.73	1.95	Div'd Decl'd per sh ^B	2.45
3.55	4.57	2.86	4.88	3.95	5.32	5.73	7.78	8.67	8.67	10.07	13.94	14.76	12.73	11.05	11.99	12.10	11.65	Cap'l Spending per sh	13.25
15.01	7.43	10.04	13.62	16.52	18.57	20.30	23.66	25.92	29.21	30.20	32.44	30.86	28.95	30.50	33.64	34.55	36.55	Book Value per sh ^C	44.00
347.21	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	Common Shs Outst'g ^D	325.81
12.9	--	10.0	7.8	7.0	NMF	11.7	13.0	16.0	12.4	9.7	10.3	11.8	9.7	12.7	13.0	16.1		Avg Ann'l P/E Ratio	13.5
.74	--	.51	.43	.40	NMF	.62	.70	.85	.75	.65	.66	.74	.62	.71	.68	.80		Relative P/E Ratio	.85
4.1%	3.9%	--	--	--	3.1%	2.6%	2.6%	2.2%	2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.8%		Avg Ann'l Div'd Yield	3.5%
CAPITAL STRUCTURE as of 9/30/15																			
Total Debt \$12406 mill. Due in 5 Yrs \$3094 mill.																			
LT Debt \$10957 mill. LT Interest \$499 mill.																			
(LT interest earned: 5.1x)																			
Leases, Uncapitalized Annual rentals \$473 mill.																			
Pens. Assets-12/14 \$3454 mill. Oblig. \$4517 mill.																			
Pfd Stock \$2022 mill. Pfd Div'd \$113 mill.																			
4,800,198 sh. 4.08%-4.78%, \$25 par, call. \$25.50-																			
-\$28.75/sh.; 3,250,000 sh. variable, noncum., call.																			
\$100; 1,250,000 sh. 6.5%, cum., \$100 liq. value;																			
350,000 sh. 6.25%, \$1000 liq. value; 460,012 sh.																			
5.1%-5.75%, \$2500 liq. value.																			
Common Stock 325,811,206 shs. as of 10/23/15																			
MARKET CAP: \$20 billion (Large Cap)																			
ELECTRIC OPERATING STATISTICS																			
2012 2013 2014																			
% Change Retail Sales (KWH)																			
+2.6 -3 +2.1																			
Avg. Indust. Use (MWH)																			
763 791 788																			
Avg. Indust. Revs. per KWH (¢)																			
7.50 8.00 8.86																			
Capacity at Peak (Mw)																			
NA NA NA																			
Peak Load, Summer (Mw)																			
21981 22534 23055																			
Annual Load Factor (%)																			
52.7 52.1 52.3																			
% Change Customers (yr-end)																			
+4 +6 +6																			
Fixed Charge Cov. (%)																			
308 295 306																			
ANNUAL RATES																			
Past 10 Yrs. Past 5 Yrs. Est'd '12-'14																			
of change (per sh)																			
Revenues 1.0% -1.0% 3.0%																			
"Cash Flow" 7.0% 3.5% 5.5%																			
Earnings 10.0% 4.5% 3.5%																			
Dividends -- 2.5% 10.0%																			
Book Value 6.5% 2.0% 6.0%																			
Cal-endar	QUARTERLY REVENUES (\$ mill.)				Full Year														
	Mar.31	Jun.30	Sep.30	Dec.31															
2012	2415	2653	3734	3060	11862														
2013	2632	3046	3960	2943	12581														
2014	2926	3016	4356	3115	13413														
2015	2512	2908	3763	3017	12200														
2016	2750	3100	3900	3150	12900														
Cal-endar	EARNINGS PER SHARE ^A				Full Year														
	Mar.31	Jun.30	Sep.30	Dec.31															
2012	.54	.55	1.09	2.39	4.55														
2013	.78	.78	1.41	.81	3.78														
2014	.61	1.07	1.51	1.15	4.33														
2015	.91	1.15	1.15	.59	3.80														
2016	.90	.90	1.50	.80	4.10														
Cal-endar	QUARTERLY DIVIDENDS PAID ^B				Full Year														
	Mar.31	Jun.30	Sep.30	Dec.31															
2012	.325	.325	.325	.325	1.30														
2013	.3375	.3375	.3375	.3375	1.35														
2014	.355	.355	.355	.355	1.42														
2015	.4175	.4175	.4175	.4175	1.67														
2016	.48																		
BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 4.9 mill. customers in a 50,000 sq. mi. area in central, coastal, and southern California (excl. Los Angeles and San Diego). Discontinued Edison Mission Energy (independent power producer) in '12. Elec. revenue breakdown: residential, 37%; commercial, 44%; industrial, 6%; other, 13%. Generating sources: gas, 8%; nuclear, 6%; hydro, 2%; purchased, 84%. Fuel costs: 42% of revs. '14 reported deprec. rate: 4.0%. Has 13,700 employees. Chairman, President & CEO: Theodore F. Craver, Jr. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Internet: www.edison.com.																			
Edison International's utility subsidiary received an order in its general rate case. In November, the California Public Utilities Commission (CPUC) reduced Southern California Edison's rates by \$451 million, retroactive to the start of 2015. A provision in the decision will also force the company to take an aftertax charge of \$382 million (\$1.17 a share) to write off some regulatory assets. On a positive note, SCE's tariffs rose by \$209 million at the beginning of 2016 and will climb by \$272 million at the start of 2017.																			
The utility has another regulatory matter pending. SCE was required to put forth a Distribution Resources Plan, which deals with issues such as integrating distributed generation with the electric grid. Its current estimate is that it will spend \$347 million-\$560 million through 2017 and \$1.405 billion-\$2.585 billion from 2018 through 2020. The former amount would be recorded for future recovery through a memorandum account, the latter through a general rate case. When the CPUC will rule on the utility's proposal is not known.																			
One more rate filing is upcoming. SCE will file another general rate case in September. New tariffs will take effect at the start of 2018. The company (and other utilities in California) were granted a one-year postponement by the CPUC for their next cost-of-capital cases, which will be filed in April of 2017.																			
We estimate that earnings will increase solidly in 2016. The utility will benefit from the rate increase and growth in its rate base. In fact, the rate base is likely to advance 7%-8% in 2016 and 2017.																			
The board of directors raised the dividend significantly, effective with the January payment. The board boosted the annual disbursement by \$0.25 a share (15%). The company has established a target of a 45%-55% payout ratio of SCE's earnings.																			
The stock's dividend yield is below average, by utility standards. This reflects Edison International's strong dividend growth prospects though the end of the decade. Total return potential over the that period is a cut above the industry mean.																			
Paul E. Debbas, CFA January 29, 2016																			

EL PASO ELECTRIC NYSE-EE					RECENT PRICE	38.70	P/E RATIO	18.1 (Trailing: 18.3 Median: 15.0)	RELATIVE P/E RATIO	1.10	DIV'D YLD	3.2%	VALUE LINE	Target Price Range							
TIMELINESS	3	Raised 11/13/15	High: 19.1	22.4	25.0	28.2	25.5	21.1	28.7	35.7	35.3	39.1	42.2	41.3				2018	2019	2020	
SAFETY	2	Raised 5/11/07	Low: 13.1	17.8	18.2	20.8	15.2	11.6	18.7	26.7	29.2	31.8	33.4	33.8							
TECHNICAL	3	Lowered 1/1/16	LEGENDS 5.0 x "Cash Flow" p sh Relative Price Strength Options: Yes Shaded area indicates recession																		
BETA	.75	(1.00 = Market)																			
2018-20 PROJECTIONS																					
Price	Gain	Ann'l Total																			
High	45	(+15%)																			
Low	35	(-10%)																			
Insider Decisions																					
to Buy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Options	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
to Sell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Institutional Decisions																					
to Buy	88	76	78															Percent shares traded	21		
to Sell	74	71	63																14		
Hld's(000)	38975	39499	39588																7		
CAPITAL STRUCTURE as of 9/30/15																					
Total Debt \$1253.0 mill. Due in 5 Yrs \$201.9 mill.																					
LT Debt \$1134.3 mill. LT Interest \$68.2 mill.																					
(LT interest earned: 2.5x)																					
Leases, Uncapitalized																					
Annual rentals \$1.4 mill.																					
Pension Assets-12/14																					
\$272.9 mill.																					
Oblig. \$341.1 mill.																					
Pfd Stock None																					
Common Stock 40,426,668 shs.																					
as of 10/31/15																					
MARKET CAP: \$1.6 billion (Mid Cap)																					
ELECTRIC OPERATING STATISTICS																					
2012 2013 2014																					
% Change Retail Sales (KWH)																					
+7 +4 -1.6																					
Avg. Indust. Use (MWH)																					
21659 21908 21505																					
Avg. Indust. Revs. per KWH (¢)																					
NA NA NA																					
Capacity at Peak (Mw)																					
1765 1852 1879																					
Peak Load, Summer (Mw)																					
1688 1750 1766																					
Annual Load Factor (%)																					
NA NA NA																					
% Change Customers (yr-end)																					
+1.5 +1.3 +1.3																					
Fixed Charge Cov. (%)																					
302 280 251																					
ANNUAL RATES																					
Past 10 Yrs. Past 5 Yrs. Est'd '12-'14																					
of change (per sh)																					
Revenues 4.5% 1.5% 3.5%																					
"Cash Flow" 6.5% 7.5% 5.5%																					
Earnings 13.5% 6.5% 3.5%																					
Dividends -- -- 5.0%																					
Book Value 8.5% 8.0% 4.5%																					
Cal-endar																					
QUARTERLY REVENUES (\$ mill.)																					
Mar.31 Jun.30 Sep.30 Dec.31																					
Full Year																					
2012																					
168.6 228.3 267.2 188.8																					
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177.3 240.1 282.7 190.3																					
2014																					
185.5 251.8 283.6 196.6																					
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163.7 219.5 289.7 177.1																					
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(A) Diluted EPS. Excl. nonrecur. gains (losses): '01, 15¢; '02, (\$1.04); '03, 33¢ net; '05, 21¢; '12, (\$1.26); '13, (\$1.14); '14, (\$56); '15, (\$5.93). '14 EPS don't add due to rounding. © 2015 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.	Next earnings report due early Feb. (B) Div'ds charged in '14: \$35.82/sh. (D) In mill. (E) Rate base: Net original cost. Allowed return on equity (blended): 10%; earned on avg. com. eq., '14: 10.5%. Regulatory Climate: Average.	Company's Financial Strength B++ Stock's Price Stability 95 Price Growth Persistence 20 Earnings Predictability 75
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FIRSTENERGY NYSE-FE					RECENT PRICE	29.48	P/E RATIO	13.5	(Trailing: 22.0 Median: 15.0)	RELATIVE P/E RATIO	0.76	DIV'D YLD	5.0%	VALUE LINE			
TIMELINESS	4	Lowered 12/12/14	High: 43.4	53.4	61.7	75.0	84.0	53.6	47.8	46.5	51.1	46.8	40.8	41.7	Target Price Range		
SAFETY	3	Lowered 2/22/13	Low: 35.2	37.7	47.8	57.8	41.2	35.3	33.6	36.1	40.4	31.3	30.0	28.9	2018	2019	2020
TECHNICAL	2	Raised 11/20/15	LEGENDS 0.78 x Dividends p sh divided by Interest Rate Relative Price Strength Options: Yes Shaded area indicates recession														
BETA	.70	(1.00 = Market)															
2018-20 PROJECTIONS			Price	45	Gain	(+55%)	Ann'l Total Return	15%									
High	Low	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Insider Decisions			D	J	F	M	A	M	J	J	A						
to Buy	0	0	0	0	0	0	0	0	0	0	0						
Options	0	0	0	1	0	0	0	0	0	0	0						
to Sell	1	1	2	2	0	2	0	0	0	0	0						
Institutional Decisions			4Q2014	1Q2015	2Q2015												
to Buy	227	204	199														
to Sell	205	232	214														
Hld's(000)	315687	318281	315722														
			Percent shares traded	30	20	10											

GREAT PLAINS EN'GY NYSE-GXP										RECENT PRICE	26.56	P/E RATIO	17.1	(Trailing: 19.8 Median: 16.0)	RELATIVE P/E RATIO	0.97	DIV'D YLD	4.0%	VALUE LINE					
TIMELINESS	3	Raised 12/18/15	High: 35.7	32.8	32.8	33.4	29.3	20.5	19.9	22.1	22.8	24.9	29.5	30.3	Target Price Range					2018	2019	2020		
SAFETY	3	Lowered 12/26/08	Low: 27.9	27.1	27.1	26.9	15.6	10.2	16.6	16.3	19.5	20.4	23.8	24.1										
TECHNICAL	1	Raised 12/18/15	LEGENDS 0.70 x Dividends p sh divided by Interest Rate Relative Price Strength Options: Yes Shaded area indicates recession																					
BETA	.85	(1.00 = Market)																						
2018-20 PROJECTIONS																								
Price	35	20	Gain	(+30%)	Ann'l Total Return	10%																		
High	35	20	Gain	(+30%)	Ann'l Total Return	10%																		
Low	20																							
Insider Decisions																								
J	F	M	A	M	J	J	A	S																
to Buy	0	0	0	0	0	0	0	0																
Options	0	0	0	0	0	0	0	0																
to Sell	0	0	0	0	0	0	0	0																
Institutional Decisions																								
1Q2015	125	122	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108			
to Buy	125	122	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108			
to Sell	148	125	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134			
Hld's(000)	121848	130044	125340	125340	125340	125340	125340	125340	125340	125340	125340	125340	125340	125340	125340	125340	125340	125340	125340	125340	125340			
Percent shares traded	24	16	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8			
1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC 18-20						
14.50	18.02	23.61	26.91	31.04	33.13	34.85	33.30	37.89	14.00	14.51	16.62	17.03	15.05	15.90	16.66	15.85	17.10	Revenues per sh				19.25		
3.63	4.63	4.70	4.40	4.69	4.75	4.54	3.86	4.24	3.09	3.27	4.12	3.51	3.45	4.01	4.01	3.95	4.60	"Cash Flow" per sh				6.00		
1.26	2.05	1.59	2.04	2.27	2.46	2.18	1.62	1.86	1.16	1.03	1.53	1.25	1.35	1.62	1.57	1.35	1.75	Earnings per sh ^A				2.00		
1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	.83	.83	.84	.86	.88	.94	1.00	1.06	Div'd Decl'd per sh ^B				1.20		
2.97	6.67	4.38	1.91	2.19	2.66	4.49	6.05	6.15	8.86	6.49	4.76	3.40	4.01	4.42	5.10	5.20	4.05	Cap'l Spending per sh				3.75		
13.97	14.88	12.59	13.58	13.82	15.35	16.37	16.70	18.18	21.39	20.62	21.26	21.74	21.75	22.58	23.26	23.60	24.30	Book Value per sh ^C				26.75		
61.91	61.91	61.91	69.20	69.26	74.37	74.74	80.35	86.23	119.26	135.42	135.71	136.14	153.53	153.87	154.16	154.50	154.75	Common Shs Outst'g ^D				155.50		
20.0	12.4	15.9	11.1	12.2	12.6	14.0	18.3	16.3	20.5	16.0	12.1	16.1	15.5	14.2	16.5	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio				13.5		
1.14	.81	.81	.61	.70	.67	.75	.99	.87	1.23	1.07	.77	1.01	.99	.80	.87			Relative P/E Ratio				.85		
6.6%	6.5%	6.6%	7.3%	6.0%	5.4%	5.5%	5.6%	5.5%	7.0%	5.0%	4.5%	4.1%	4.1%	3.8%	3.6%			Avg Ann'l Div'd Yield				4.6%		
CAPITAL STRUCTURE as of 9/30/15										2604.9	2675.3	3267.1	1670.1	1965.0	2255.5	2318.0	2309.9	2446.3	2568.2	2450	2650	Revenues (\$mill)	3000	
Total Debt \$4105.7 mill. Due in 5 Yrs \$1472.6 mill.										164.2	127.6	159.2	119.5	135.6	211.7	174.4	199.9	250.2	242.8	215	275	Net Profit (\$mill)	315	
LT Debt \$3763.5 mill. LT Interest \$188.9 mill.										18.7%	27.0%	30.7%	34.5%	25.0%	31.7%	32.7%	34.3%	34.0%	32.3%	35.0%	35.0%	Income Tax Rate	35.0%	
(LT interest earned: 2.4x)										2.1%	8.4%	10.6%	46.8%	57.0%	25.7%	3.9%	3.3%	10.4%	12.8%	5.0%	2.0%	AFUDC % to Net Profit	2.0%	
Leases, Uncapitalized Annual rentals \$14.2 mill.										47.5%	30.6%	40.7%	49.7%	53.2%	50.2%	47.8%	44.9%	50.0%	49.0%	51.0%	47.5%	Long-Term Debt Ratio	48.0%	
Pension Assets-12/14 \$730.0 mill.										50.9%	67.5%	57.9%	49.6%	46.2%	49.2%	51.6%	54.4%	49.4%	50.4%	48.5%	52.0%	Common Equity Ratio	51.5%	
Oblig. \$1186.8 mill.										2403.3	1988.4	2709.8	5146.2	6044.5	5867.6	5741.2	6135.8	7029.1	7113.1	7525	7255	Total Capital (\$mill)	8050	
Pfd Stock \$39.0 mill. Pfd Div'd \$1.6 mill.										2765.6	3066.2	3444.5	6081.3	6651.1	6892.3	7053.5	7402.1	7746.4	8279.6	8690	8875	Net Plant (\$mill)	9050	
390,000 shs. 3.80% to 4.50% (all \$100 par & cum.), callable from \$101 to \$103.70.										8.2%	7.9%	7.5%	3.5%	3.9%	5.3%	5.0%	5.0%	5.0%	4.7%	4.0%	5.0%	Return on Total Cap'l	5.0%	
Common Stock 154,369,354 shs.										13.0%	9.2%	9.9%	4.6%	4.8%	7.2%	5.8%	5.9%	7.1%	6.7%	6.0%	7.0%	Return on Shr. Equity	7.5%	
as of 11/2/15										13.3%	9.4%	10.1%	4.6%	4.8%	7.3%	5.8%	5.9%	7.2%	6.7%	6.0%	7.5%	Return on Com Equity ^E	7.5%	
MARKET CAP: \$4.1 billion (Mid Cap)										3.2%	NMF	.9%	NMF	.9%	3.4%	2.0%	2.2%	3.2%	2.7%	1.5%	3.0%	Retained to Com Eq	3.0%	
ELECTRIC OPERATING STATISTICS										76%	104%	91%	NMF	81%	54%	66%	63%	55%	60%	73%	60%	All Div'ds to Net Prof	62%	
										2012	2013	2014												
% Change Retail Sales (KWH)										1.8	+2	+4												
Avg. Indust. Use (MWH)										1443	1424	1455												
Avg. Indust. Revs. per KWH (¢)										6.23	6.80	6.79												
Capacity at Peak (Mw)										6719	NA	NA												
Peak Load, Summer (Mw)										5653	NA	NA												
Annual Load Factor (%)										49.6	NA	NA												
% Change Customers (avg.)										+2	+7	+9												
Fixed Charge Cov. (%)										235	267	261												
ANNUAL RATES										Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14												
of change (per sh)												'18-'20												
Revenues										-6.5%	-6.5%	3.5%												
"Cash Flow"										-2.0%	1.5%	8.0%												
Earnings										-4.0%	2.5%	5.0%												
Dividends										-6.0%	-8.5%	6.0%												
Book Value										4.5%	2.5%	3.0%												
Cal-endar	QUARTERLY REVENUES (\$ mill.)					Full Year																		
	Mar.31	Jun.30	Sep.30	Dec.31																				
2012	479.7	603.6	746.2	480.4	2309.9																			
2013	542.2	600.3	765.0	538.8	2446.3																			
2014	585.1	648.4	782.5	552.2	2568.2																			
2015	549.1	609.0	781.4	510.5	2450																			
2016	600	650	850	550	2650																			
Cal-endar	EARNINGS PER SHARE ^A					Full Year																		
	Mar.31	Jun.30	Sep.30	Dec.31																				
2012	d.07	.41	.95	.03	1.35																			
2013	.17	.41	.93	.11	1.62																			
2014	.15	.34	.95	.12	1.57																			
2015	.12	.28	.82	.13	1.35																			
2016	.20	.40	1.00	.15	1.75																			
Cal-endar	QUARTERLY DIVIDENDS PAID ^B					Full Year																		
	Mar.31	Jun.30	Sep.30	Dec.31																				
2011	.2075	.2075	.2075	.2125	.84																			
2012	.2125	.2125	.2125	.2175	.86																			
2013	.2175	.2175	.2175	.23	.88																			
2014	.23	.23	.23	.245	.94																			
2015	.245	.245	.245	.2625																				
BUSINESS: Great Plains Energy Incorporated is a holding company for Kansas City Power & Light and two other subsidiaries, which supply electricity to 844,000 customers in western Missouri (71% of revenues) and eastern Kansas (29%). Acq'd Aquila 7/08. Sold Strategic Energy (energy-marketing subsidiary) in '08. Electric revenue breakdown: residential, 40%; commercial, 39%; industrial, 9%; other, 12%. Generating sources: coal, 64%; nuclear, 13%; wind, 1%; gas & oil, 1%; purchased, 21%. Fuel costs: 29% of revs. '14 reported deprec. rate (utility): 3.0%. Has 2,900 employees. Chairman: Michael J. Chesser. President & CEO: Terry Bassham, Inc.: Missouri. Address: 1200 Main St., Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.greatplainsenergy.com.																								
Great Plains Energy's largest utility subsidiary received a rate order in Kansas. Kansas City Power & Light was granted a tariff hike of \$48.7 million (9.0%), based on a return of 9.3% on a common-equity ratio of 50.48%. New rates took effect at the start of October. KCP&L also received a rate increase of \$89.7 million (11.8%), based on a 9.5% return on a 50.09% common-equity ratio, in mid-September. There were good and bad aspects to the rate orders. KCP&L received more than 75% of what it requested, and will earn a return on its entire investment in an environmental upgrade to a coal-fired plant. The utility was also granted a fuel-adjustment mechanism in Missouri. (It already had one in Kansas.) However, the company did not get other regulatory mechanisms it sought in Missouri, and is disappointed with the low allowed ROEs. It has appealed these issues to the courts in Missouri and Kansas. We have cut our 2015 earnings estimate by a nickel a share. Third-quarter profits fell short of our estimate. Management narrowed its share-earnings guid-																								
ance from \$1.35-\$1.60 to \$1.35-\$1.45, and our revised profit estimate is at the low end of this range. In recent years, the company has been earning mediocre ROEs due to the effects of regulatory lag. The rate orders came too late to have much effect on earnings this year, but . . . We continue to expect a significant profit increase in 2016. The rate orders should help the utility reduce (but won't eliminate) the regulatory lag problem. Our forecast would result in a 30% bottom-line increase over our 2015 estimate. Great Plains Energy will put forth 2016 guidance in its conference call in late February. The board of directors has raised the dividend. The board boosted the annual disbursement by \$0.07 a share (7.1%), effective with the fourth-quarter payment. Great Plains is now targeting a payout ratio in a range of 55%-70%, but wants to narrow this to 60%-70% after 2016. Great Plains Energy stock has an average dividend yield for a utility. With the recent price near the midpoint of our 3- to 5-year Target Price Range, total return potential is low. Paul E. Debbas, CFA December 18, 2015																								

(A) EPS diluted. Excl. nonrecurring gains (loss): '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. Egs. may not sum to total due to rounding. Next earnings report due in early February. (B)	Div'ds historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan avail. ■ Shareholder investment plan avail. (C) Incl. deferred debits. In '14: \$25.26/sh. (D) In mill.	(E) Rate Base: Net original cost. Rate allowed on com. eq. in Idaho in '11: 9.5%-10.5%; earned on avg. system com. eq., '14: 9.9%. Regulatory Climate: Above Average.	Company's Financial Strength Stock's Price Stability Price Growth Persistence Earnings Predictability	B++ 95 85 95
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(A) Diluted EPS. Excl. nonrecurring gain (losses): '00, '05%; '02, '06%; '03, '05; '11, '24%; '13, '00%; gain on discontinued operations: '13, 44%. Next earnings report due late	Jan. (B) Div'ds historically paid in mid-Mar., mid-June, mid-Sept., & mid-Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '14:	\$4.95/sh. (D) In millions, adjusted for stock split. (E) Rate allowed on com. eq. in '13: 9.5%-11.5%; earned on avg. com. eq., '14: 13.0%. Regulatory Climate: Average.	Company's Financial Strength Stock's Price Stability Price Growth Persistence Earnings Predictability	A 100 70 75
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(A) Diluted EPS. Excl. nonrec. gains (losses): '99, \$(2.44); '04, \$6.95; '09, 1.8¢; '11, (68¢); '12, (15¢); '10 '15, (21¢); gain from disc. ops.: '08, 41¢. '13 EPS don't add due to rounding.	14 due to change in shs. Next earnings report due mid-Feb. (B) Div'ds historically paid in mid-Jan., Apr., July, and Oct. ■ Div'dly reinvest. plan avail. † Shareholder investment plan avail. (C)	Incl. intang. In '14: \$13.28/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '15: 10.4%; earned on avg. com. eq., '14: 9.5%. Regulatory Climate: Above Avg.	Company's Financial Strength Stock's Price Stability Price Growth Persistence Earnings Predictability	B+ 95 35 60
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(A) Diluted EPS. Excl. nonrec. losses: '02, 77¢; '09, 1\$45; excl. gains (losses) from discontinued ops.: '00, 22¢; '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). © 2016 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. The PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.	Next earnings report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. * Div'd reinvestment plan avail. (C) Incl. deferred	charges. In '14: \$12.30/sh. (D) In mill. (E) Rate based: Fair value. Rate allowed on com. eq., '12: 10%; earned on avg. com. eq., '14: 9.3%. Regulatory Climate: Average.	Company's Financial Strength A+ Stock's Price Stability 100 Price Growth Persistence 60 Earnings Predictability 75
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(A) EPS dil. Excl. n/r gains (losses): '99, 8¢; '00, 21¢; '01, (15¢); '03, 6¢; '05, (56¢); '08, (33.77); '10, '13, 11¢, 88¢. '13, (16); Excl. disc. ops.: '08, 42¢; '09, 78¢. Egs. may not	sum due to rounding. Next egs. rpt. due late February. (B) Div'ds hist. pd. in Feb., May, Aug., Nov. ■ Div'd reinvest. plan avail. ↑ Shareholder invest. plan avail. (C) Incl. intang. '14:	\$3.49/sh. (D) In mill., adjust. for split. (E) Rate base: net orig. cost. ROE allowed in '11: 10.0%; earned on avg. com. eq. '13: 10.0%. Reg. Climate: avg. (F) Excl. First Choice.	Company's Financial Strength Stock's Price Stability Price Growth Persistence Earnings Predictability	B 85 45 35
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PORTLAND GENERAL NYSE-POR				RECENT PRICE	37.69	P/E RATIO	16.8	(Trailing: 18.8 Median: NMF)	RELATIVE P/E RATIO	1.02	DIV'D YLD	3.3%	VALUE LINE																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																										
TIMELINESS	3	Raised 8/14/15		High: 35.0	31.3	27.7	21.4	22.7	26.0	28.1	33.3	40.3	41.0		Target Price Range	2018	2019	2020																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																					
SAFETY	2	Raised 5/4/12		Low: 24.2	25.5	15.4	13.5	17.5	21.3	24.3	27.4	29.0	33.0																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																										
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(A) Diluted EPS. Excl. nonrecurring loss: '13, 42¢. Next earnings report due mid-Feb. (B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '14: \$6.31/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on com. eq. in '16: 9.6%; earned on avg. com. eq., '14: 9.4%. Regulatory Climate: Average. (F) Summer peak in '12. (G) '05 per-share data are pro forma, based on shares outstanding when stock began trading in '06.

(A) Diluted EPS. Excl. nonrecurring loss: '13, 42¢. Next earnings report due mid-Feb. (B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '14: \$6.31/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on com. eq. in '16: 9.6%; earned on avg. com. eq., '14: 9.4%. Regulatory Climate: Average. (F) Summer peak in '12. (G) '05 per-share data are pro forma, based on shares outstanding when stock began trading in '06.

Company's Financial Strength B++
Stock's Price Stability 100
Price Growth Persistence 60
Earnings Predictability 70

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(A) Diluted EPS. Excl. nonrec. gain (losses): '03, '06; '09, '25%; '13, '03%; '14, '09%; '15, '03%. '14 EPS don't add due to rounding. Next earnings report due late Jan. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. Div'd reinvest. plan avail. * Shareholder invest. plan avail. (C) Incl. def'd charges. In '14: \$7.92/sh. (D) In mill. (E) Rate base: AL, MS, MS, FL, GA, orig. cost. All'd return on com. eq. (blended): 12.5%; earn. on avg. com. eq., '14: 12.7%. Reg. Clim.: GA, AL Above Avg., MS, FL Avg. (F) Winter peak in '14.	Company's Financial Strength A Stock's Price Stability 100 Price Growth Persistence 40 Earnings Predictability 100
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(A) EPS diluted from 2010 onward. Excl. non-recur. gains (losses): '99, '\$1.31; '00, '\$1.07; '01, '27¢; '02, '\$12.06; '03, '77¢; '08, '39¢; '11, '14¢. Earnings may not sum due to rounding.	Next egs. rep't due early February. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. reg. assets. In 2014:	\$6.48/sh. (D) Rate base determined; fair value; Rate allowed on common eqn in '14: 10.0%; earned on avg. com. eq., '14: 9.5%. Regul. Clim.: Avg. (E) In mill.	Company's Financial Strength B++ Stock's Price Stability 100 Price Growth Persistence 75 Earnings Predictability 85
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XCEL ENERGY NYSE-XEL										RECENT PRICE	37.21	P/E RATIO	16.9 (Trailing: 17.9; Median: 15.0)	RELATIVE P/E RATIO	1.03	DIV'D YLD	3.7%	VALUE LINE	Target Price Range						
TIMELINESS 2 Raised 12/25/15										High: 18.8	20.2	23.6	25.0	22.9	21.9	24.4	27.8	29.9	31.8	37.6	38.3	2018	2019	2020	
SAFETY 1 Raised 5/1/15										Low: 15.5	16.5	17.8	19.6	15.3	16.0	19.8	21.2	25.8	26.8	27.3	31.8				
TECHNICAL 3 Lowered 12/25/15										LEGENDS 0.74 x Dividends p sh divided by Interest Rate Relative Price Strength Options: Yes Shaded area indicates recession															
BETA .65 (1.00 = Market)																									
2018-20 PROJECTIONS																									
Price 40 Gain (+5%) Ann'l Total Return 6% Nil																									
Insider Decisions																									
Institutional Decisions																									
CAPITAL STRUCTURE as of 9/30/15																									
Leases, Uncapitalized																									
Pension Assets-12/14																									
Pfd Stock None																									
Common Stock 507,496,978 shs. as of 10/26/15																									
MARKET CAP: \$19 billion (Large Cap)																									
ELECTRIC OPERATING STATISTICS																									
ANNUAL RATES																									
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Exhibit 1: Proxy Group Criteria

	Company [1]	Ticker	Credit Rating (Criteria: Investment Grade)	Generation Assets Included in Rate Base	Regulated Revenue / Total Revenue (Criteria: >60%)	Regulated Income / Total Income (Criteria: >60%)	Regulated Electric Revenue / Total Reg. Revenue (Criteria: >80%)	Regulated Electric Income / Total Reg. Income(Criteria: >80%)	Fuel Mix: Percent Nuclear [2]	Fuel Mix: Percent Hydro [2]
1	ALLETE, Inc.	ALE	BBB+	Yes	90%	101%	97%	97%	0%	6%
2	Ameren Corporation	AEE	BBB+	Yes	100%	102%	83%	89%	11%	7%
3	American Electric Power Company, Inc.	AEP	BBB	Yes	92%	85%	100%	100%	8%	3%
4	Duke Energy Corporation	DUK	A-	Yes	92%	102%	98%	97%	17%	7%
5	Edison International	EIX	BBB+	Yes	100%	101%	100%	100%	20%	36%
6	El Paso Electric Company	EE	BBB	Yes	100%	100%	100%	100%	31%	0%
7	Emera Inc.[3]	EMA	BBB+	Yes	87%	86%	98%	86%	0%	0%
8	Entergy Corporation	ETR	BBB	Yes	79%	96%	98%	99%	15%	0%
9	FirstEnergy Corporation	FE	BBB-	Yes	64%	113%	100%	100%	40%	18%
10	Fortis Inc. [3]	FTS	A-	Yes	94%	94%	63%	62%	0%	1%
11	Great Plains Energy Inc.	GXP	BBB+	Yes	100%	101%	100%	100%	8%	0%
12	IDACORP, Inc.	IDA	BBB	Yes	100%	100%	100%	100%	0%	52%
13	NextEra Energy, Inc.	NEE	A-	Yes	69%	72%	100%	100%	13%	0%
14	PG&E Corporation	PCG	BBB	Yes	100%	100%	80%	96%	29%	50%
15	Pinnacle West Capital Corporation	PNW	A-	Yes	100%	100%	100%	100%	18%	0%
16	PNM Resources, Inc.	PNM	BBB+	Yes	100%	99%	100%	100%	17%	0%
17	Portland General Electric Company	POR	BBB	Yes	100%	100%	100%	100%	0%	14%
18	Southern Company	SO	A-	Yes	95%	93%	100%	100%	10%	8%
19	Westar Energy, Inc.	WR	BBB+	Yes	100%	100%	100%	100%	9%	0%
20	Xcel Energy Inc.	XEL	A-	Yes	99%	99%	83%	89%	9%	3%

Notes:

[1] Eversource Energy, while otherwise meeting Concentric's screening criteria, is in the process of selling its remaining regulated generation. As such, Eversource may not be comparable to the proxy companies going forward, and was thus excluded from the comparison group.

[2] Nuclear and hydroelectric generation criteria: Companies for which nuclear and/or hydroelectric generation make up less than 5% of their generation mix were excluded from the proxy group.

[3] None of the publicly traded Canadian companies that Concentric reviewed met all of our screening criteria. Emera, Inc. ("Emera"), however, only failed the screen that each utility should have more than a minimal amount of regulated hydroelectric and/or nuclear generation. Fortis, Inc. ("Fortis"), only failed the screens that each utility should have regulated electric revenue and net income that make up greater than 80 percent of the consolidated company's regulated operations and that each utility should have a more than an minimal amount of hydroelectric and/or nuclear regulated generation. In order to broaden the proxy group to include at least a minimal number of Canadian utilities, Concentric included Emera and Fortis in the proxy group, as they otherwise meet our screening criteria.

Exhibit 2: Proxy Group Company Relevant Indicators

Parent Company Ticker	Operating Company	State or Province	Weighted Common Equity/Total Cap (%)	S&P Credit Rating	Operating Revenue: Electric	Customer % of Company (only includes total of companies with cases included)
ALE	ALLETE (Minnesota Power)	MN	54.29			100%
ALE [1]			54.29	BBB+	\$1,013,221	
AEE	Union Electric Company	MO	51.76			49%
AEE	Ameren Illinois Company	IL	50.00			51%
AEE [1]			50.87	BBB+	\$4,953,315	
AEP	Columbus Southern Power Company	OH	50.64			17%
AEP	Ohio Power Company	OH	53.79			16%
AEP	Appalachian Power Company	WV	47.16			10%
AEP	Indiana Michigan Power Company	IN	42.67			11%
AEP	Appalachian Power Company	VA	42.89			12%
AEP	Indiana Michigan Power Company	MI	42.07			3%
AEP	Southwestern Electric Power Company	AR	33.99			3%
AEP	AEP Texas Central Company	TX	40.00			19%
AEP	AEP Texas North Company	TX	40.00			4%
AEP	Southwestern Electric Power Company	TX	49.10			4%
AEP [1]			45.77	BBB	\$14,490,000	
DUK	Duke Energy Ohio, Inc.	OH	53.30			10%
DUK	Duke Energy Indiana, LLC	IN	44.44			11%
DUK	Duke Energy Florida, LLC	FL	45.74			24%
DUK	Duke Energy Carolinas, LLC	SC	53.00			8%
DUK	Duke Energy Progress, LLC	SC	44.72			2%
DUK	Duke Energy Progress, LLC	NC	53.00			18%
DUK	Duke Energy Carolinas, LLC	NC	53.00			27%
DUK [1]			50.14	A-	\$22,581,161	
EIX	Southern California Edison Company	CA	48.00			100%
EIX [1]			48.00	BBB+	\$14,195,273	
EE [2]	El Paso Electric Company		NA	BBB	\$917,525	
EMA	Maine Public Service Company	ME	50.00			6%
EMA	Emera Maine	ME	49.00			18%
EMA	Nova Scotia Power Inc.	Nova Scotia	37.50			76%

Exhibit 2: Proxy Group Company Relevant Indicators

Parent Company Ticker	Operating Company	State or Province	Weighted Common Equity/Total Cap (%)	S&P Credit Rating	Operating Revenue: Electric	Customer % of Company (only includes total of companies with cases included)
EMA [1]			40.27	BBB+	\$2,067,200	
ETR	Entergy Arkansas, Inc. [3]	AR	46.27			100%
ETR [1]			46.27	BBB	\$10,904,103	
FE	Cleveland Electric Illuminating Company	OH	49.00			22%
FE	Ohio Edison Company	OH	49.00			31%
FE	Toledo Edison Company	OH	49.00			9%
FE	Potomac Edison Company	WV	46.42			4%
FE	Jersey Central Power & Light Company	NJ	50.00			33%
FE [1]			49.22	BBB-	\$9,871,000	
FTS	Central Hudson Gas & Electric Corporation	NY	48.00			16%
FTS	Tucson Electric Power Company	AZ	43.50			22%
FTS	UNS Electric, Inc.	AZ	52.60			5%
FTS	Fortis BC Electric	British Columbia	40.00			9%
FTS	Fortis Alberta	Alberta	40.00			28%
FTS	Newfoundland Power	Newfoundland & Labrador	45.00			13%
FTS	Maritime Electric	Prince Edward Island	40.00			4%
FTS	Fortis Ontario	Ontario	40.00			4%
FTS [1]			43.31	A-	\$3,554,612	
GXP	KCP&L Greater Missouri Operations Company	MO	52.30			38%
GXP	Kansas City Power & Light Company	MO	50.09			33%
GXP	Kansas City Power & Light Company	KS	50.48			29%
GXP Weighted Average [1]			51.04	BBB+	\$2,568,200	
IDA	Idaho Power Co.	OR	49.90			100%
IDA [1]			49.90	BBB	\$1,278,651	
NEE [2]	NextEra Energy Inc.		NA	A-	\$11,421,000	
PCG	Pacific Gas and Electric Company	CA	52.00			100%
PCG [1]			52.00	BBB	\$13,658,000	
PNW	Arizona Public Service Company	AZ	53.94			100%
PNW [1]			53.94	A-	\$3,491,632	
PNM	Texas-New Mexico Power Company	TX	45.00			100%

Exhibit 2: Proxy Group Company Relevant Indicators

Parent Company Ticker	Operating Company	State or Province	Weighted Common Equity/Total Cap (%)	S&P Credit Rating	Operating Revenue: Electric	Customer % of Company (only includes total of companies with cases included)
PNM [1]			45.00	BBB+	\$1,435,853	
POR	Portland General Electric Company	OR	50.00			100%
POR [1]			50.00	BBB	\$1,900,000	
SO	Mississippi Power Company	MS	53.68			5%
SO	Alabama Power Company	AL	45.60			36%
SO	Georgia Power Company	GA	50.84			60%
SO [1]			49.09	A-	\$17,354,000	
WR	Kansas Gas and Electric Company	KS	50.13			100%
WR [1]			50.13	BBB+	\$2,601,703	
XEL	Northern States Power Company - MN	ND	52.56			3%
XEL	Public Service Company of Colorado	CO	56.00			43%
XEL	Northern States Power Company - WI	WI	52.49			8%
XEL	Southwestern Public Service Company	TX	51.00			8%
XEL	Northern States Power Company - MN	MN	52.50			38%
XEL [1]			53.89	A-	\$9,467,664	
OPG		Ontario	45.00	BBB+	\$4,963,000	

Notes:

[1] Equity Ratio Weighted by Total Retail Electric Customers. Excludes companies for which most recent rate case parameters were not provided and/or public information was not available via SNL.

[2] Recent authorized equity ratios for the operating companies of El Paso Electric Company and NextEra Energy Inc. were not available via SNL. Therefore, the equity ratios for those companies are listed as NA.

[3] Equity ratio adjusted to exclude zero cost capital items.

Exhibit 3: Proxy Company Cost Recovery Mechanisms

Company	Inter-Rate Case Cost Recovery and other Adjustment Mechanisms
OPG	Nuclear liability Nuclear development Capacity refurbishment Ancillary services net revenue – hydro & nuclear Hydroelectric water conditions Income and other taxes Nuclear and hydro deferral and variance over/under recovery Bruce lease net revenues Pension and OPEB cost Pension & OPEB cash payment and Pension & OPEB cash versus accrual differential Niagara Tunnel Project pre-December 2008 Disallowance Gross revenue charge Hydro incentive mechanism Hydro surplus base load generation Impact resulting from changes in station end-of-life dates
AEE	Purchased Power Cost Adjustment – Fuel Adjustment Clause (incl. Off-System Sales) Conservation Program Expense – DSM Program Recovery Partial Decoupling Renewables Expense – Renewable Energy Standards rate adjustment Environmental Compliance – Hazardous Materials Adjustment Clause Rider RTO-Related Transmission Expense Other – Bad Debt Cost Recovery Other – Certain Taxes and Franchise Fee Recovery
ALE	Purchased Power Cost Adjustment Conservation Program Expense Renewables Expense Environmental Compliance RTO-Related Transmission Expense
AEP	Purchased Power Cost Adjustment Conservation Program Expense – Energy Efficiency Rider Partial Decoupling Renewables Expense Environmental Compliance – Environmental Adjustment Clause Environmental Compliance – Energy Efficiency Rider Generation Capacity Generation Capacity – Big Sandy Plant Recovery Generic Infrastructure – T&D and storage system improvement charge rider Generic Infrastructure – CWIP Recovery Generic Infrastructure – Distribution Cost Recovery Factor Generic Infrastructure – Electric Security Plans RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery Other – OSS Sharing Mechanism Other – Compliance and Cyber-security Requirements

Exhibit 3: Proxy Company Cost Recovery Mechanisms

Company	Inter-Rate Case Cost Recovery and other Adjustment Mechanisms
DUK	Purchased Power Cost Adjustment Conservation Program Expense Conservation Program Expense – Energy Efficiency Recovery Rider Partial Decoupling Renewables Expense Renewables Expense – EPS Rider Environmental Compliance Generation Capacity – Capacity Cost Recovery Clause Generic Infrastructure – Electric Security Plans Recovery RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery Other – OSS Margin Sharing Mechanism
EE	Purchased Power Cost Adjustment Conservation Program Expense Generic Infrastructure – Distribution Cost Recovery Factor Other – Certain Taxes and Franchise Fee Recovery
EIX	Purchased Power Cost Adjustment Full Decoupling
ETR	Purchased Power Cost Adjustment Conservation Program Expense Conservation Program Expense – Energy Efficiency Programs Partial Decoupling Environmental Compliance – Environmental Adjustment Clause Generation Capacity – Capacity Acquisition Rider Generation Capacity – New generation and Capacity Additions Generic Infrastructure – Distribution Cost Recovery Generic Infrastructure – Government-related Expenses RTO-Related Transmission Expense Other – Storm Cost Securitization
FE	Purchased Power Cost Adjustment – Electric Fuel Rate Conservation Program Expense Partial Decoupling Renewables Expense Generic Infrastructure – Electric Security Plans Recovery RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery
GXP	Purchased Power Cost Adjustment Conservation Program Expense Partial Decoupling Renewables Expense Environmental Compliance RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery Other – Energy Cost Adjustment Mechanism
IDA	Purchased Power Cost Adjustment Renewables Expense Conservation Program Expense

Exhibit 3: Proxy Company Cost Recovery Mechanisms

Company	Inter-Rate Case Cost Recovery and other Adjustment Mechanisms
	Partial Decoupling

Exhibit 3: Proxy Company Cost Recovery Mechanisms

Company	Inter-Rate Case Cost Recovery and other Adjustment Mechanisms
NEE	Purchased Power Cost Adjustment Conservation Program Expense Environmental Compliance Generation Capacity – Capacity Cost Recovery Clause Generic Infrastructure – Transmission Cost of Service Mechanism Other – Certain Taxes and Franchise Fee Recovery
PCG	Purchased Power Cost Adjustment Full Decoupling
PNM	Purchased Power Cost Adjustment Conservation Program Expense Renewables Expense Environmental Compliance Generic Infrastructure – Distribution Cost Recovery Factor Other – Certain Taxes and Franchise Fee Recovery
PNW	Purchased Power Cost Adjustment Conservation Program Expense Partial Decoupling Renewables Expense Generation Capacity RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery
POR	Purchased Power Cost Adjustment Partial Decoupling Renewables Expense
SO	Purchased Power Cost Adjustment Conservation Program Expense Environmental Compliance Generation Capacity Other – Certain Taxes and Franchise Fee Recovery Other – Storm Cost Securitization
WR	Purchased Power Cost Adjustment Conservation Program Expense Partial Decoupling – Energy Efficiency Program Recovery Renewables Expense Environmental Compliance RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery
XEL	Purchased Power Cost Adjustment Conservation Program Expense Conservation Program Expense – Demand-Side Management Rider Conservation Program Expense – Energy Efficiency Rider Renewables Expense Environmental Compliance Generic Infrastructure – Distribution Cost Recovery Factor Generic Infrastructure – Transmission Cost Recovery Rider Generic Infrastructure – Infrastructure Rider RTO-Related Transmission Expense

Exhibit 3: Proxy Company Cost Recovery Mechanisms

Company	Inter-Rate Case Cost Recovery and other Adjustment Mechanisms
	Other – Certain Taxes and Franchise Fee Recovery
	Other – OSS Sharing Mechanism
	Other – Limited Issue Reopener
	Other – Lost Revenue Rider Associated with University Discounts
	Other – "Non-asset-based" Wholesale Power Margin Sharing
	Other – Renewable Energy Credit Sales

Exhibit 3: Proxy Company Cost Recovery Mechanisms

Company	Inter-Rate Case Cost Recovery and other Adjustment Mechanisms
FTS	Deferred income taxes Employee future benefits Manufactured gas plant ("MGP") site remediation deferral Rate stabilization accounts Deferred energy management costs Deferred lease costs Derivative instruments Deferred operating overhead costs Deferred net losses on disposal of utility capital assets and intangible assets Final mine reclamation and retiree health care costs Property tax deferrals Natural gas for transportation incentives Income taxes recoverable on OPEB plans Carrying charges – employee future benefits Customer Care Enhancement Project cost deferral Non-ARO removal cost provision Rate stabilization accounts Deferred income taxes Employee future benefits Customer and community benefits obligation AESO charges deferral Renewable energy surcharge Carrying charges – employee future benefits Derivative instruments Full Decoupling Renewables Expense Purchased Power Cost Adjustment Conservation Program Expense Partial Decoupling – Lost Fixed Cost Recovery Mechanism Environmental Compliance Other – Certain Taxes and Franchise Fee Recovery RTO-Related Transmission Expense

Exhibit 3: Proxy Company Cost Recovery Mechanisms

Company	Inter-Rate Case Cost Recovery and other Adjustment Mechanisms
EMA	Deferred income tax regulatory asset Unamortized defeasance costs Fuel adjustment mechanism Deferrals related to derivative instruments Large industrial customers fixed cost deferral Stranded cost recovery Pension and post-retirement medical plan Stranded cost revenue & purchase power reconciliation deferrals Purchase power contracts Hydro-Québec Obligation November 2014 Maine storm 2013 Maine ice storm Earnings Share Mechanism Asset impairment recovery Seabrook nuclear project Deferral of income and capital taxes not included in Q1 2005 rates Smart Grid Rate stabilization fixed cost deferral Self-Insurance Fund Deferrals related to derivative instruments Deferred income tax regulatory liabilities Maine FERC ROE

Sources:

U.S. Companies: SNL RRA Adjustment Mechanism Report as of October 2, 2015.

EMA & FTS: 2014 Consolidated Financial Statements and 2014 Annual Report and above SNL report, respectively

OPG: EB-2014-0370 and Company Data.

Board Staff Interrogatory #15

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Ref: Exh C1-1-1 Attachment 1, page 34, Figure 5 and page 62, Exhibit 1: Proxy Group Criteria

Concentric has selected a proxy group that it has used for its analysis. Figure 5 on page 34 and Exhibit 1 on page 62 summarize some of the characteristics.

- a) For each firm listed in Figure 5, what percentage of the firm's generation assets are subject to regulation?
- b) For each firm listed in Figure 5, please provide the following:
 - i. Total generation capacity (MW)
 - ii. Generation capacity (MW) devoted to the unregulated wholesale market.
- c) Does Concentric consider regulated and wholesale electricity generation to have the same business risk? Please explain.

Response

The following response was provided by Concentric Energy Advisors:

- a) For each proxy company listed in Figure 5 the percentage of the firm's generation assets subject to rate regulation is shown in the Chart 1 below.

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Chart 1

Sum of Capacity Owned (MW)	2014
Ultimate Parent	Regulated Generation Assets (%)
ALLETE, Inc.	78%
Ameren Corporation	100%
American Electric Power Company, Inc.	82%
Duke Energy Corporation	96%
Edison International	100%
El Paso Electric Company	100%
Emera Incorporated	57%
Entergy Corporation	77%
FirstEnergy Corp.	48%
Fortis Inc.	93%
Great Plains Energy Inc.	100%
IDACORP, Inc.	99%
NextEra Energy, Inc.	58%
PG&E Corporation	100%
Pinnacle West Capital Corporation	100%
PNM Resources, Inc.	100%
Portland General Electric Company	100%
Southern Company	79%
Westar Energy, Inc.	100%
Xcel Energy Inc.	100%

Regulated Generation Assets (%) based on operating capacity.

Sources: SNL Financial Template: Power Plant Capacity by Owner Summary, Fortis, Inc. 2014 Annual Report, and Emera Inc. Management's Discussion and Analysis at February 6, 2015.

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- i. Chart 2 below contains the total generation capacity (MW) for each proxy company listed in Figure 5.

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Chart 2

Company	2014 Operating Capacity (MW)
ALLETE, Inc.	2,507
Ameren Corporation	11,130
American Electric Power Company, Inc.	32,413
Duke Energy Corporation	56,291
Edison International	3,127
El Paso Electric Company	2,054
Emera Incorporated	4,378
Entergy Corporation	26,565
FirstEnergy Corp.	16,387
Fortis Inc.	3,753
Great Plains Energy Inc.	6,740
IDACORP, Inc.	3,878
NextEra Energy, Inc.	46,970
PG&E Corporation	7,709
Pinnacle West Capital Corporation	6,320
PNM Resources, Inc.	2,403
Portland General Electric Company	3,504
Southern Company	45,650
Westar Energy, Inc.	6,305
Xcel Energy Inc.	18,429

Sources: SNL Financial Template: Power Plant Capacity by Owner Summary, Fortis, Inc. 2014 Annual Report, and Emera Inc. Management's Discussion and Analysis, February 6, 2015

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- ii. Chart 3 below provides each proxy company's non-rate-regulated generation capacity (MW) for the companies listed in Figure 5. Note, for purposes of responding to this interrogatory, Concentric has classified all non-rate regulated capacity as "unregulated wholesale market" capacity, regardless of whether each firm's non-rate-regulated plants are subject to a purchased power agreement ("PPA"). Depending on the terms of any such PPAs, the cost recovery risk of such contracted plants may be more similar to regulated plants than pure merchant plants.

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Chart 3

Company	2014 Non-Rate-Regulated Operating Capacity (MW)
ALLETE, Inc.	542
Ameren Corporation	0
American Electric Power Company, Inc.	5,713
Duke Energy Corporation	2,528
Edison International	0
El Paso Electric Company	0
Emera Incorporated	1,895
Entergy Corporation	6,020
FirstEnergy Corp.	8,571
Fortis Inc.	274
Great Plains Energy Inc.	5
IDACORP, Inc.	22
NextEra Energy, Inc.	19,500
PG&E Corporation	0
Pinnacle West Capital Corporation	0
PNM Resources, Inc.	0
Portland General Electric Company	0
Southern Company	9,540
Westar Energy Inc.	0
Xcel Energy Inc.	0

Sources: SNL Financial Template: Power Plant Capacity by Owner Summary, Fortis, Inc. 2014 Annual Report, and Emera Inc. Management's Discussion and Analysis, February 6, 2015

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- c) No, Concentric does not consider regulated and wholesale electricity generation to have the same business risk. Merchant generation is generally considered to be riskier than rate-regulated generation. The reason for this is merchant generators generally recover their costs through competitive markets whereas rate-regulated generators generally recover costs through rates that are designed to reflect the generators' underlying cost of service. Concentric notes, however, that many merchant power plants sell their power under PPAs, which differentiate them from pure merchant power plants in terms of cost recovery risk.

Board Staff Interrogatory #16

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Ref: Exh C1-1-1 Attachment 1, page 38, Figure 8

Concentric has selected a proxy group for its analysis of the appropriate capital structure.

- a) Does Concentric have data on the composition of NEE's (NextEra) capital spending? If yes, please provide this data.
- b) Does Concentric have data on the capital spending of the listed companies during the last 2 to 4 years? If yes, please provide the data in electronic format.

Response

The following response was provided by Concentric Energy Advisors:

- a) The data presented in Exhibit C1-1-1 Attachment 1 is from Value Line, which does not provide a further breakdown of each proxy company's capital spending.
- b) Please see Attachment 3.1-Staff-16.b for 4 years of capital spending for each of the proxy companies.

Capital Spending per share					
		2012	2013	2014	2015
ALLETE, Inc.	ALE	10.3	7.93	12.48	5.84
Ameren Corporation	AEE	5.49	5.87	7.66	8.12
American Electric Power Company, Inc.	AEP	6.45	7.75	8.68	9.37
Duke Energy Corporation	DUK	7.81	7.83	7.62	9.83
Edison International	EIX	12.73	11.05	11.99	12.97
El Paso Electric Company	EE	6.7	7.18	8.5	8.55
Entergy Corporation	ETR	18.18	15.73	14.82	16.79
FirstEnergy Corp.	FE	7.09	6.9	8.42	6.83
Great Plains Energy Inc.	GXP	4.01	4.42	5.1	4.42
IDACORP, Inc.	IDA	4.78	4.68	5.45	5.84
NextEra Energy, Inc.	NEE	22.31	15.36	15.84	18.17
PG&E Corporation	PCG	10.74	11.4	10.16	10.51
Pinnacle West Capital Corporation	PNW	8.24	9.36	8.38	9.84
PNM Resources, Inc.	PNM	3.88	4.37	5.78	7.01
Portland General Electric Company	POR	4.01	8.4	12.87	6.73
Southern Company	SO	5.54	6.16	6.58	6.22
Westar Energy, Inc.	WR	6.4	6.08	6.47	4.95
Xcel Energy Inc.	XEL	5.27	6.82	6.33	7.26

Source: Value Line as of September 28, 2016

Common Shares Outstanding (thousands)					
		2012	2013	2014	2015
ALLETE, Inc.	ALE	39,400	41,400	45,900	49,100
Ameren Corporation	AEE	242,635	242,635	242,635	242,635
American Electric Power Company, Inc.	AEP	485,668	487,777	489,403	491,053
Duke Energy Corporation	DUK	704,000	706,000	707,000	688,000
Edison International	EIX	325,811	325,811	325,811	325,811
El Paso Electric Company	EE	40,112	40,267	40,357	40,444
Entergy Corporation	ETR	177,808	178,371	179,241	178,389
FirstEnergy Corp.	FE	418,216	418,629	421,103	423,560
Great Plains Energy Inc.	GXP	153,530	153,866	154,163	154,404
IDACORP, Inc.	IDA	50,157	50,233	50,270	50,341
NextEra Energy, Inc.	NEE	424,000	435,000	443,000	461,000
PG&E Corporation	PCG	430,718	456,670	475,913	492,025
Pinnacle West Capital Corporation	PNW	109,743	110,182	110,571	110,980
PNM Resources, Inc.	PNM	79,654	79,654	79,654	79,654
Portland General Electric Company	POR	75,556	78,086	78,228	88,793
Southern Company	SO	867,768	887,086	907,777	911,721
Westar Energy, Inc.	WR	126,504	128,254	131,687	141,353
Xcel Energy Inc.	XEL	487,960	497,972	505,733	507,536

Source: Value Line as of September 28, 2016

Capital Spending (thousands)						
		2012	2013	2014	2015	
ALLETE, Inc.	ALE	\$ 405,820	\$ 328,302	\$ 572,832	\$ 286,744	
Ameren Corporation	AEE	\$ 1,332,064	\$ 1,424,266	\$ 1,858,582	\$ 1,970,194	
American Electric Power Company, Inc.	AEP	\$ 3,132,561	\$ 3,780,275	\$ 4,248,014	\$ 4,601,163	
Duke Energy Corporation	DUK	\$ 5,498,240	\$ 5,527,980	\$ 5,387,340	\$ 6,763,040	
Edison International	EIX	\$ 4,147,577	\$ 3,600,214	\$ 3,906,476	\$ 4,225,771	
El Paso Electric Company	EE	\$ 268,751	\$ 289,115	\$ 343,031	\$ 345,795	
Entergy Corporation	ETR	\$ 3,232,541	\$ 2,805,774	\$ 2,656,347	\$ 2,995,152	
FirstEnergy Corp.	FE	\$ 2,965,155	\$ 2,888,537	\$ 3,545,684	\$ 2,892,918	
Great Plains Energy Inc.	GXP	\$ 615,654	\$ 680,089	\$ 786,230	\$ 682,464	
IDACORP, Inc.	IDA	\$ 239,749	\$ 235,089	\$ 273,971	\$ 293,990	
NextEra Energy, Inc.	NEE	\$ 9,459,440	\$ 6,681,600	\$ 7,017,120	\$ 8,376,370	
PG&E Corporation	PCG	\$ 4,625,914	\$ 5,206,043	\$ 4,835,280	\$ 5,171,187	
Pinnacle West Capital Corporation	PNW	\$ 904,280	\$ 1,031,301	\$ 926,588	\$ 1,092,047	
PNM Resources, Inc.	PNM	\$ 309,056	\$ 348,086	\$ 460,398	\$ 558,375	
Portland General Electric Company	POR	\$ 302,981	\$ 655,919	\$ 1,006,799	\$ 597,575	
Southern Company	SO	\$ 4,807,435	\$ 5,464,450	\$ 5,973,173	\$ 5,670,905	
Westar Energy, Inc.	WR	\$ 809,624	\$ 779,786	\$ 852,018	\$ 699,697	
Xcel Energy Inc.	XEL	\$ 2,571,547	\$ 3,396,166	\$ 3,201,292	\$ 3,684,708	
Emera Incorporated [3]	EMA	\$ 374,582	\$ 269,507	\$ 345,551	\$ 370,848	
Fortis Inc. [3]	FTS	\$ 838,162	\$ 914,358	\$ 1,295,341	\$ 1,676,323	

Emera Incorporated [1]	EMA	\$ 491,600	\$ 353,700	\$ 453,500	\$ 486,700	
Fortis Inc. [2]	FTS	\$ 1,100,000	\$ 1,200,000	\$ 1,700,000	\$ 2,200,000	

0.761965 [3]

[1] In thousands of Canadian dollars. Sources: Emera 2015 - Financial Statements, page 125; Emera 2013 - Financial Statements, page 98

[2] In thousands of Canadian dollars. Source: Fortis 2015 Annual Report, page 6

[3] 1.00 CAD = 0.761965 USD, Source: <http://www.x-rates.com/calculator/?from=CAD&to=USD&amount=1>, September 29, 2016

Board Staff Interrogatory #17

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Ref: Exh C1-1-1/Attachment 1, page 25 of 73

In its evidence, Concentric makes reference in footnote 46 to a methodology paper by Dominion Bond Rating Service (DBRS) as the source for its summary in Table 3.

- a) Please file the DBRS study entitled: "Methodology: Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry," October 19, 2015.
- b) Are there any other studies or reports conducted or commissioned by credit rating agencies regarding the criteria on the form of economic regulation that credit rating agencies use for assessing the credit rating of regulated firms that Concentric is aware of and used in its report? If so, please provide copies of all such reports.
- c) If such reports in b) were used, please indicate how and where they were used by Concentric in its analysis. If they were not used, please indicate why not.

Response

The following response was provided by Concentric Energy Advisors:

- a) Please see Attachment 1.
- b) In its April 2016 ratings report on OPG, DBRS stated, "DBRS believes that profitability for OPG could continue to be challenged following a switch to an IR framework, as the introduction of productivity and efficiency targets could further depress earnings."¹ Please see Attachment 2.

At the time Concentric filed its report, Concentric was not aware of any other reports from credit rating agencies regarding how the form of economic regulation (*i.e.*, cost of service vs. incentive regulation) affects credit risk. In August 2016, however, S&P published a report expanding on the factors that it considers in assessing the regulatory environments of U.S. investor-owned utilities (please see Attachment 3). In that report, S&P provides its views regarding how incentive regulation affects credit quality. The S&P report is generally consistent with the DBRS report, and provides additional evidence that rating

¹ DBRS Rating Report, "Ontario Power Generation Inc.," April 25, 2016, at 1.

1 agencies tend to view incentive regulation as potentially negative for credit quality,
2 depending on how the incentive regulation regime is designed and the duration of the IR
3 plan.
4

5 *If a jurisdiction uses incentives as the primary ratemaking tool and institutes a*
6 *comprehensive incentive program that allows revenues and costs to diverge,*
7 *we evaluate the incentive mechanisms' effect on a utility's earnings capability*
8 *and stability. A common approach features an extended period between rate*
9 *case reviews, during which rates change according to a formula based on*
10 *inflation, a predetermined productivity factor, and capital spending. An*
11 *incentive-based program can be close to credit neutral compared with*
12 *systems that permit more frequent and dynamic rate changes if the risk is*
13 *symmetrical (i.e., an equal opportunity to earn over or under the authorized*
14 *return and equivalent reward or penalty for doing so) and limited (a maximum*
15 *or minimum earnings band). The effect on regulatory risk depends on*
16 *whether we believe the efficiency targets are realistic and achievable, the*
17 *regulator's treatment of disparities in actual versus authorized spending, and*
18 *the framework's flexibility to adjust returns for capital market conditions. If*
19 *there are operating standards, we determine whether they fairly reward or*
20 *punish utilities if performance deviates from expectations.*

21
22 *There is a muted effect on regulatory risk in jurisdictions where incentives are*
23 *not central, but are instead used only to augment cost-of-service regulation. A*
24 *moderate amount of incentives that carry symmetrical risks can even modestly*
25 *support better credit quality. For example, a fuel adjustment and purchased-*
26 *power clause with a sharing mechanism that affects less than 10% of the total*
27 *fuel costs and cuts both ways when commodity markets change can modestly*
28 *reduce risk by offering the utility a mild incentive for effective procurement and*
29 *efficient operations, without unduly exposing it to commodity price risk.²*

30
31 S&P concludes:
32

33 *We typically view jurisdictions as credit supportive if regulators use*
34 *symmetrical incentive mechanisms sparingly in the rate-setting process.*
35 *When incentives play a larger role in the rate-setting approach, but are well-*
36 *designed to evenly allocate risk, we see less support for credit quality. We*
37 *regard still lower jurisdictions where incentives dominate and are poorly*
38 *designed. Jurisdictions where incentives significantly degrade risk and are*
39 *part of a comprehensive incentive regime harbor the most risk for creditors.³*
40
41

² S&P Global Ratings, Assessing U.S. Investor-Owned Utility Regulatory Environments, August 10, 2016, at 5.

³ Ibid, at 6.

1 c) The April 2016 DBRS report discussed in part (b) was reviewed as part of Concentric's
2 analysis and considered in terms of how the ratings agencies view OPG from a business
3 and financial risk perspective. The report was specifically cited in Exhibit C1-1-1
4 Attachment 1, page 17.

5
6 As discussed in the response to part (b), the S&P report was unavailable at the time
7 Concentric filed its report. The S&P report was published in August, 2016 and provides
8 additional insight into how credit rating agencies view the effect of incentive regulation on
9 credit risk. The S&P report is generally consistent with the DBRS report, and provides
10 additional evidence that rating agencies tend to view incentive regulation as potentially
11 negative for credit quality, depending on how the incentive regulation regime is designed
12 and the duration of the IR plan.

OCTOBER 2015



METHODOLOGY

Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry

PREVIOUS RELEASE: OCTOBER 2014

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DBRS is a full-service credit rating agency established in 1976. Spanning North America, Europe and Asia, DBRS is respected for its independent, third-party evaluations of corporate and government issues. DBRS's extensive coverage of securitizations and structured finance transactions solidifies our standing as a leading provider of comprehensive, in-depth credit analysis.

All DBRS ratings and research are available in hard-copy format and electronically on Bloomberg and at DBRS.com, our lead delivery tool for organized, web-based, up-to-the-minute information. We remain committed to continuously refining our expertise in the analysis of credit quality and are dedicated to maintaining objective and credible opinions within the global financial marketplace.

Scope and Limitations

This methodology represents the current DBRS approach for ratings in the regulated electric, gas and water utility industry. It describes the DBRS approach to credit analysis, which includes consideration of historical and expected business and financial risk factors as well as industry-specific issues, regional nuances and other subjective factors and intangible considerations. DBRS's approach incorporates a combination of both quantitative and qualitative factors. The methods described herein may not be applicable in all cases; the considerations outlined in DBRS methodologies are not exhaustive and the relative importance of any specific consideration can vary by issuer. In certain cases, a major strength can compensate for a weakness and, conversely, a single weakness can override major strengths of the issuer in other areas. DBRS may use, and appropriately weight, several methodologies when rating issuers that are involved in multiple business lines. Further, this methodology is meant to provide guidance regarding the DBRS methods used in the sector and should not be interpreted with formulaic inflexibility, but understood in the context of the dynamic environment in which it is intended to be applied.

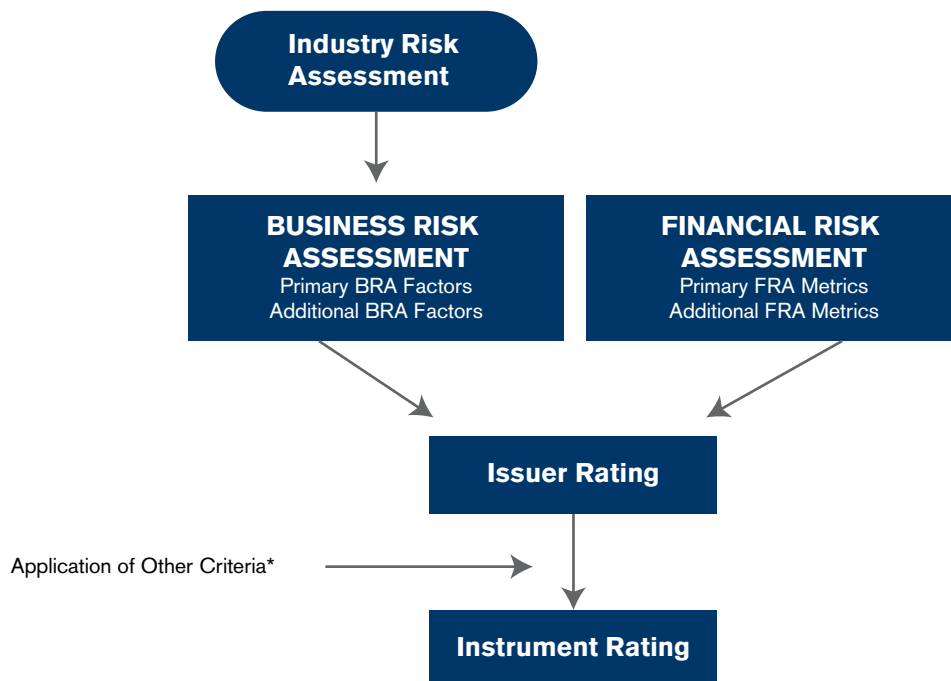
Introduction to DBRS Methodologies

- DBRS publishes rating methodologies to give issuers and investors insight into the rationale behind DBRS's rating opinions.
- In general terms, DBRS ratings are opinions that reflect the creditworthiness of an issuer, a security or an obligation. DBRS ratings assess an issuer's ability to make timely payments on outstanding obligations (whether principal, interest, preferred share dividends or distributions) with respect to the terms of an obligation. In some cases (e.g., non-investment grade corporate issuers), DBRS ratings may also address recovery prospects for a specific instrument given the assumption of an issuer default.
- DBRS operates with a stable rating philosophy; in other words, DBRS strives to factor the impact of a cyclical economic environment into its ratings wherever possible, which minimizes rating changes due to economic cycles. Rating revisions do occur, however, when more structural changes, either positive or negative, have occurred, or appear likely to occur in the near future.
- DBRS also publishes criteria which are an important part of the rating process. Criteria typically cover areas that apply to more than one industry. Both methodologies and criteria are publicly available on the DBRS website and many criteria are listed below under "Rating the Specific Instrument and Other Criteria."

Overview of the DBRS Rating Process

- There are generally three components to the DBRS corporate rating process: (1) an industry risk assessment (IRA); (2) an issuer rating; and (3) considerations for specific securities. The figure below outlines this process.
- An IRA is a relative ranking of most industries that have a DBRS methodology, typically using just three ranges of the DBRS long-term debt rating scale (i.e., “A,” BBB and BB), without making use of the “high” or “low” descriptors. The IRA is a general indication of credit risk in an industry and considers, among other things, an industry’s: (1) profitability and cash flow; (2) competitive landscape; (3) stability; (4) regulation; and (5) other factors. An “industry,” for the purposes of the IRA, is defined as those firms that are generally the larger, more established firms within the countries where the majority of DBRS’s rated issuers are based; this remains true for DBRS methodologies that are more global in nature. The IRA helps DBRS set the BRA grid (see below) in that it positions, in an approximate way, an average firm in the industry onto the BRA grid. For firms in industries with low IRAs, the IRA can, in effect, act as a constraint or “cap” on the issuer’s rating.
- The issuer rating is DBRS’s assessment of the probability of default of a specific issuer. It is a function of: (1) the business risk assessment (BRA), determined by assessing each of the primary and (where relevant) additional BRA factors in the BRA grid for a specific issuer; and (2) the financial risk assessment (FRA), determined by assessing each of the primary and (where relevant) additional FRA metrics. The two components, BRA and FRA, are combined to determine the issuer rating; in most cases, the BRA will have greater weight than the FRA in determining the issuer rating. Throughout the BRA and FRA determination process, DBRS performs a consistency check of the issuer on these factors against the issuer’s peers in the same industry.
- The issuer rating is then used as a basis for specific instrument ratings. DBRS assigns, for example, a recovery rating and notches up or down from the issuer rating to determine a specific instrument rating for instruments of non-investment grade corporate issuers. (See “Rating the Specific Instrument and Other Criteria” below.)

DBRS Rating Analysis Process



* Depending on the instrument, “other criteria” may include the recovery methodology for non-investment grade issuers or the preferred share and hybrid criteria, for example. Please refer to the section below entitled “Rating the Specific Instrument and Other Criteria” for a list of these criteria, as well as other criteria that may be applicable at any stage of the rating process.

Regulated Electric, Natural Gas and Water Utilities Industry

- This methodology applies to companies with regulated utility operations (i.e., regulated electric generation, distribution or transmission, natural gas distribution and/or water and waste-water utilities).
- For companies that have both material regulated and non-regulated operations in other related industry segments (e.g., non-regulated electricity generation, energy marketing or trading), DBRS applies both this and the *Rating Companies in the Independent Power Producer Industry* methodology. For pipeline or diversified energy companies, see *Rating Pipeline and Diversified Energy Companies*. For energy-related project finance transactions, see *Rating Project Finance*, *Rating Wind Power Projects* or *Rating Solar Power Projects*.
- Per the three-tier industry risk rating system described on the previous page, this industry's IRA is "A."
- For the electric-related utilities, there are three broad business areas: generation, transmission and distribution. Some utilities are fully integrated and participate in all three, while others may be involved in only one or two segments.
- Regulated utilities are typically monopolistic. Because of the large amount of fixed costs, one large utility firm can generally provide service at a lower cost than two or more firms serving the same customer base. Utilities are generally regulated by an administrative tribunal (i.e., a government agency) created by statute to assist ratepayers in obtaining reliable energy services on a cost-effective basis. Rate-setting mechanisms generally ensure that utilities receive adequate revenue requirements to recover all costs prudently incurred to provide service including cost of capital.
- Utilities are typically regulated either under a traditional cost-of-service (COS) or some form of performance-based framework.
- Utilities with a higher proportion of residential and commercial customers possess the ability to better weather economic downturns and demonstrate more stable operating performances than utilities with a greater exposure to industrial customers, who are more inclined to seek economic alternatives and are prone to economic cyclicalities.
- The risk of environmental regulation is evolving, particularly for the electric industry; however, for a regulated utility, future cost increases attributable to environmental regulation would be expected to be recovered from ratepayers.
- Long-term threats include competition from new distributed energy resources and small-scale power generation sources located close to end users, providing an alternative to the traditional electric power transmission and distribution grid.
- Water and waste-water utilities typically operate under similar regulatory frameworks to other regulated utility operations; however, the water and waste-water sector may be more fragmented and regulation may show more variation, given that regulation is generally at the municipal level rather than the state/provincial level. In addition, capital spending may be more volatile for water and waste-water utilities.

Regulated Electric, Natural Gas and Water Utilities Business Risk Assessment

PRIMARY BRA FACTORS

- The BRA grid below shows the primary factors used by DBRS in determining the BRA. While these primary factors are shown in general order of importance, depending on a specific issuer's business activities, this ranking can vary by issuer.
- The quality of the regulatory regime is the main driving factor for regulated utilities as it is the most important BRA factor. The regulatory framework also influences a company's FRA as the deemed capital structure and return on equity (ROE) are often set by the regulator.

Regulated Electric, Natural Gas and Water Utilities Primary BRA Factors

Rating	<u>AA</u>	<u>A</u>	<u>BBB</u>	<u>BB/B</u>
Regulation (The most important BRA factor – see Appendix for further details.)	• Highly supportive regulatory framework with the majority of relevant key regulatory risk factors in the Appendix considered to be "excellent."	• Supportive regulatory framework with the majority of relevant key regulatory risk factors in the Appendix considered to be "good" or better.	• Reasonable regulatory framework with the majority of relevant key regulatory risk factors in the Appendix considered to be "satisfactory" or better.	• Poor regulatory framework with the majority of relevant key regulatory risk factors in the Appendix considered to be "below average" and/or "poor."
Business Mix	• Primarily an electric transmission and/or distribution with modest (if any) power generation. • Well-diversified utilities with a range of businesses throughout the utility value chain (natural gas transmission and distribution, electricity transmission and distribution as well as complementary energy services and generation activities).	• A "wires" or gas distribution, water or waste-water, or an integrated utility or generator with a low-risk profile.	• Integrated utility or generator with a moderate-risk profile.	• Integrated utility or generator with high-risk profile.
Franchise and Customer Mix	• Strong and consistent levels of load growth. • Economically vibrant service territory. • Customer mix primarily residential and commercial.	• Reasonable load growth generally tracking the broader economy. • Economically strong service territory. • Customer mix heavily weighted toward residential and commercial.	• Minimal load growth. • Economically stagnant service territory. • Customer mix a balance of residential, commercial and industrial.	• Consistent load declines. • Economically weak service territory. • Customer mix weighted toward cyclical industrials.

The following BRA risk factors are relevant to issuers in all industries (although the relevance of sovereign risk can vary considerably):

Sovereign Risk	The issuer rating may, in some cases, be constrained by the credit risk of the sovereign; in other words, the rating of the country in which the issuer operates generally sets a maximum rating for the issuer. If the issuer operates in multiple countries and a material amount of its business is conducted in a lower-rated country, DBRS may reflect this risk by downwardly adjusting its issuer rating.
Corporate Governance	Please refer to DBRS Criteria: Evaluating Corporate Governance for further information on how DBRS evaluates corporate governance and management.

Regulated Electric, Natural Gas and Water Utilities Business Risk Assessment (CONTINUED)

ADDITIONAL BRA FACTORS

The additional BRA factors discussed below may be very important for certain issuers, depending upon their activities, but they do not necessarily apply to all issuers in the industry.

Capital Spending

- Utilities are capital-intensive businesses. A utility might undertake large capital projects to either meet growing demand in a high-growth franchise area or replace significant aging assets. This could potentially lead to cost overruns and weaker financial metrics, at least during the growth phase.
- For utilities undergoing very significant multi-year capital expansion programs, capital spending may be considered a primary rating factor. This would be particularly relevant for companies with significant nuclear generation development.

Supply/Demand Considerations

- The provision of utility services depends on the presence of adequate supplies of energy (e.g., natural gas and electricity) to meet end-user demand. For electric utilities, generation of sufficient electricity to meet demand is paramount.

Ownership

- The existence of a highly-rated parent typically does not result in a lift to a stand-alone utility's rating; however, DBRS may impute some level of support in a utilities rating if it is owned by a highly-rated city, despite no explicit guarantee being in place, given the potential unique circumstances of the city/utility relationship.

Size

- The size of the utility could limit its ability to operate effectively and efficiently. At times, sizing may have an impact on a company's ability to raise funds, increase rates or execute capital projects. Under performance-based regulation, size would also have an impact on a company's ability to contain costs to achieve operating efficiency targets set by regulators.

Geographical Diversification

- Geographical diversification could improve the BRA by reducing concentration risk in any one regulatory jurisdiction.

Environmental Issues

- DBRS assesses the extent to which utilities face government laws and regulations that can have an impact on a company's business and prospects. Regulated utilities may either be a direct source of greenhouse gas emissions (e.g., thermal power producer) or may transport energy derived from sources that produce emissions (e.g., a wires utility moving third-party power through its lines).

Retail Exposure

- Distribution companies may be required to provide retail services to customers, such as electricity supply. Under this framework, utilities, depending on commercial arrangements, could be exposed to significant market risk. Key areas of analysis therefore include hedging policies, counterparty risk and the size of the operation. Rates are, however, generally passed on to rate payers, thereby reducing the risk to the utility.

Competitive Environment

- DBRS assess the degree of competition from other forms of energy or any other potential threats to natural monopoly, including material development of new distributed energy resources and small-scale power generation sources located close to end users, which could ultimately provide an alternative to the traditional electric power transmission and distribution grid.

Regulated Electric, Natural Gas and Water Utilities Financial Risk Assessment

PRIMARY FRA METRICS

- The FRA grid below shows the primary FRA metrics used by DBRS to determine the FRA. While these primary FRA metrics are shown in general order of importance, depending upon an issuer's activities, the ranking can vary by issuer.
- DBRS ratings are based heavily on future performance expectations, so while past metrics are important, any final rating will incorporate DBRS's opinion on future metrics, a subjective but critical consideration.
- It is not unusual for a company's metrics to move in and out of the ranges noted in the grid below, particularly for cyclical industries. In the application of this matrix, DBRS looks beyond the point-in-time ratio.
- Financial metrics depend on accounting data whose governing principles vary by jurisdiction and, in some cases, industry. DBRS may adjust financial statements to permit comparisons with issuers using different accounting principles.
- Please refer to *DBRS Criteria: Financial Ratios and Accounting Treatments – Non Financial Companies* for definitions of, and common adjustments to, these ratios in the FRA grid below.
- DBRS considers an issuer's financial policy including factors such as its targeted financial leverage, its dividend policy and the likelihood of share buybacks or other management actions that may favour equity holders over bondholders.
- Liquidity can be an important credit risk factor, especially for lower-rated non-investment grade issuers. While ratios such as the current or quick ratio can give an indication of certain short-term assets in comparison with short-term liabilities, DBRS will typically review all material sources of liquidity (including, for example, cash on hand, cash flow from operations, availability of bank funding, etc.) in comparison with all material short- and medium-term uses of liquidity (such as operations, capital expenditures (capex), mandatory debt repayments, share buybacks and dividends, etc.).
- While free cash flow (i.e., net of changes in working capital, dividends and capex, etc.) can be volatile and, on occasion, negative, DBRS may use this and/or other cash flow metrics to assess a company's ability to generate cash to repay debt.
- While market pricing information (such as market capitalization or credit spreads) may on occasion be of interest to DBRS, particularly where it suggests that an issuer may have difficulty in raising capital, this information does not usually play a material role in DBRS's more fundamental approach to assessing credit risk.

Regulated Electric, Natural Gas and Water Utilities – Primary FRA Metrics

Primary Metric	<u>AA</u>	<u>A</u>	<u>BBB</u>	<u>BB/B</u>
Cash flow-to-debt	> 17.5%	12.5% to 17.5%	10% to 12.5%	< 10%
Debt-to-capital	< 55%	55% to 65%	65% to 75%	> 75%
EBIT-to-interest	> 2.8x	1.8x to 2.8x	1.5x to 1.8x	< 1.5x

ADDITIONAL FRA METRICS

- While the primary FRA metrics above will be the most important metrics that DBRS will use in determining the FRA of an issuer, other metrics may be used, depending upon an issuer's activities, capital structure, pension liabilities and off-balance sheet obligations.
- DBRS notes that utilities rated below investment grade are typically rated as such because of heightened business risk levels rather than for credit metric reasons.

Blending the BRA and FRA into an Issuer Rating

- The final issuer rating is a blend of the BRA and FRA. In most cases, the BRA will have greater weight than the FRA in determining the issuer rating.
- At the low end of the rating scale, however, particularly in the B range and below, the FRA and liquidity factors play a much larger role and the BRA would, therefore, typically receive a lower weighting than it would at higher rating levels.
- For regulated utilities, the quality of the regulatory regime, which is a BRA factor, often drives the FRA of a company since the deemed capital structure and ROE are often set by the regulator.

Rating the Specific Instrument and Other Criteria

- For non-investment grade corporate issuers, DBRS assigns a recovery rating and reflects the seniority and the expected recovery of a specific instrument, under an assumed event of default scenario, by notching up or down from the issuer rating in accordance with the principles outlined in the criteria *DBRS Recovery Ratings for Non-Investment Grade Corporate Issuers*.
- Preferred share and hybrid considerations are discussed under *Preferred Share and Hybrid Criteria for Corporate Issuers*.
- The issuer rating (which is an indicator of the probability of default of an issuer's debt) is the basis for rating specific instruments of an issuer, where applicable. DBRS uses a hierarchy in rating long-term debt that affects issuers that have classes of debt that do not rank equally. In most cases, lower-ranking classes would receive a lower DBRS rating. For more detail on this subject, please refer to the general rating information contained in the DBRS rating policy "Underlying Principles."
- For a discussion on the relationship between short- and long-term ratings and more detail on liquidity factors, please refer to the DBRS policy "Short-Term and Long-Term Rating Relationships" and the criteria *Commercial Paper Liquidity Support Criteria for Non-Bank Issuers*.
- The existence of holding companies can have a meaningful impact on individual security ratings. For more detail on this subject, please refer to the criteria *Rating Holding Companies and Their Subsidiaries*.
- Guarantees and other types of support are discussed in *DBRS Criteria: Guarantees and Other Forms of Explicit Support*.
- For further information on how DBRS evaluates corporate governance, please refer to *DBRS Criteria: Evaluating Corporate Governance*.
- Please refer to *DBRS Criteria: Financial Ratios and Accounting Treatments – Non Financial Companies* for definitions of, and common adjustments to, these ratios.

Appendix: Regulation

- In determining the BRA for regulation (see page 6), DBRS reviews the following ten considerations to assess the regulatory framework in which the utility conducts its business.
- The ranking of the factors is based on a five-point scale (excellent, good, satisfactory, below average and poor).
- The first four factors are generally of greater importance than the others when assessing regulatory risk; however, the factors are not given a specific weighting when assessing the regulatory framework.

CONSIDERATION 1: DEEMED EQUITY

Definition

Deemed equity is the percentage of equity investment in the rate base on which a utility could earn a return. In general, the higher the Deemed Equity portion, the higher the earnings for a utility. In addition, utilities tend to maintain their actual capital structure in line with the regulatory capital structure.

Score	Item	Definition
Excellent	50%+	• Deemed equity represents 50% or more of utility's rate base • The treatment of deemed equity is consistent historically
Good	45.00% to 49.99%	• Deemed equity represents 45.00% to 49.99% of utility's capital structure • The treatment of deemed equity is consistent historically
Satisfactory	40.00% to 44.99%	• Deemed equity represents 40.00% to 44.99% of utility's capital structure • The treatment of deemed equity has not been consistent historically
Below Average	35.00% to 39.99%	• Deemed equity represents 35.00% to 39.99% of utility's capital structure • The treatment of deemed equity has not been consistent historically
Poor	Below 34.99%	• Deemed equity represents less than 34.99% of utility's capital structure • The treatment of deemed equity has not been consistent historically

CONSIDERATION 2: ALLOWED ROE

Definition

Allowed ROE is a measurement of returns on the deemed equity portion of the rate base. The regulator sets an allowed ROE based on a utility's business risk level (which is assessed by the regulator). In a supportive regulatory environment, utilities' actual ROEs are generally in line with the allowed ROE or exceed the allowed ROE. In an unsupportive regulatory regime, utilities often generate much lower actual ROE than the allowed ROE. DBRS will consider the utility's track record of its actual ROE outperformance/underperformance relative to allowed ROE and assess whether the key drivers of ROE outperformance/underperformance could be sustained going forward.

Score	Item	Definition
Excellent	10%+	• An allowed ROE is set at 10.00% or higher • The regulatory treatment of allowed ROE has been consistent historically
Good	9% to 10%	• An allowed ROE is set at 9.00% to 10.00% • The regulatory treatment of allowed ROE has been consistent historically
Satisfactory	8.00% to 8.99%	• An allowed ROE is set at 8.00% to 8.99% • The regulatory treatment of allowed ROE has been consistent historically
Below Average	7.00% to 7.99%	• An allowed ROE is set at 7.00% to 7.99% • The regulatory treatment of allowed ROE has NOT been consistent historically
Poor	Below 7%	• An allowed ROE is set at below 7.00% • The regulatory treatment of allowed ROE has NOT been consistent historically

Appendix: Regulation (CONTINUED)

CONSIDERATION 3: ENERGY COST RECOVERY

Definition

Fuel and purchased energy cost (F&PE) recovery certainty and the timing of recovery are critical in DBRS's assessment of a regulatory system within a certain jurisdiction. DBRS looks at the following factors: (1) whether F&PE costs are fully passed through to the customers; (2) how often a utility is allowed to adjust the F&PE costs in retail rates charged to customers; and (3) if there is a mechanism within a jurisdiction to allow utilities to make F&PE cost adjustments with no or minimal regulatory review. In addition, DBRS also focuses on the generation mix within a certain market. A high power cost market could have an impact on the utility's ability to recover the purchased power costs in a timely manner. DBRS notes that this factor is not applicable for water and waste-water utilities.

Score	Item	Definition
Excellent	Monthly/bi-monthly	- F&PE costs are fully passed through - Adjustment is made on a monthly basis - There is an automatic adjustment mechanism - The jurisdiction is in a favourable generation mix market, resulting in low power cost
Good	Quarterly	- F&PE costs are fully passed through - Adjustment is made on a quarterly basis - There is an automatic adjustment mechanism - The jurisdiction is in a favourable generation mix market, resulting in low power cost
Satisfactory	Quarterly with regulatory review	- F&PE costs are fully passed through - Adjustment is made on a quarterly basis - F&PE cost deferrals are subject to some regulatory review - The jurisdiction is in a good generation mix market
Below Average	Annually with automatic adjustment	- F&PE costs are fully passed through or utilities having minimal exposure to the energy price volatility - Adjustment is made on an annual basis and is subject to minimal or some regulatory review - The jurisdiction is in an above-average power cost market
Poor	Annually with no automatic adjustment mechanism	- F&PE costs are fully passed through or utilities having minimal exposure to the energy price volatility - Adjustment is made on an annual basis - F&PE cost deferrals are subject to regulatory review - The jurisdiction is in an above-average power cost market

Appendix: Regulation (CONTINUED)

CONSIDERATION 4: CAPITAL AND OPERATING COST RECOVERY

Definition

In assessing capital cost recovery (CCR) and operating cost recovery (OCR), DBRS focuses on the likelihood of a utility's capex being added to its rate base, along with the timing of such addition. In addition, DBRS focuses on cost-inflation adjustments which could affect the timing of OCR. In particular, DBRS looks at the following factors: (1) the utilization of future test periods for rate decisions; (2) whether the spending is allowed to be added to the rate base during the construction or will only be added when the project is completed; (3) the level of upfront capital spending required without regulatory approval; (4) the degree of regulatory lag and uncertainty with respect to CCR; and (5) whether or not there is a reasonable mechanism to deal with cost overruns.

Score	Item	Definition
Excellent	Minimal CCR and OCR lag risk	• Work-in-progress costs can be added to the rate base if capex is significant • Interim base-rate increases have been frequently authorized • Future test periods are fully incorporated for rate-case decisions • Rate cases are typically decided well within one year unless the rate cases are litigated or unusual circumstances occur • There is a reasonable mechanism to deal with cost overruns
Good	Reasonable CCR and OCR lag risk	• Capital costs are added to the rate base after completion of work • Interim base-rate increases have been authorized from time to time • Future test periods are at least partially incorporated for rate-case decisions • Rate cases are typically decided within one year unless the rate cases are litigated or unusual circumstances occur • There is a reasonable mechanism to deal with costs overruns
Satisfactory	Modestly elevated CCR and OCR lag risk	• Capex is generally pre-approved by regulator, but there is some modest upfront capital spending before regulatory approval • Interim base-rate increases have been rarely authorized • Historical test periods are commonly incorporated for rate-case decisions • Rate cases are typically decided within one year unless the rate cases are litigated or unusual circumstances occur • There is a reasonable mechanism to deal with cost overruns
Below Average	Below-average CCR and OCR lag risk	• There is significant upfront capital spending before regulatory approval • Interim base-rate increases have been rarely authorized • Historical test periods are commonly incorporated for rate-case decisions • Rate-case decisions typically take more than one year because of frequent court cases and other circumstances • There are some mechanisms to deal with cost overruns
Poor	Significant CCR and OCR lag risk	• Capex is generally not pre-approved by regulator • Capital costs are added to the rate base after completion of work • Utilities face significant regulatory lag risk with respect to CCR and OCR • There is no meaningful mechanism to deal with cost overruns.

Appendix: Regulation (CONTINUED)

CONSIDERATION 5: COST OF SERVICE VERSUS INCENTIVE REGULATION MECHANISM

Definition

In general, under COS, regulated utilities are allowed to recover prudently incurred operating costs and earn a reasonable return on their investment. Under incentive regulatory mechanism (IRM), revenue requirements for the year are based on a COS base year, adjusted for inflation (consumer price index (CPI)) and minus a productivity factor (X), which is set by the regulator. This forces utilities to maintain their operational efficiency to achieve allowed ROE. DBRS views COS as lower risk than IRM. In addition, DBRS also considers the length of an IRM period between the COS years. DBRS's scoring system gives a higher score for a shorter IRM period.

Score	Item	Definition
Excellent	COS	COS regime allowing utilities to recover prudently and reasonably incurred operating costs
Good	IRM (three years or shorter)	- IRM regime with maximum three years between the COS years - For an IRM period of more than three years, there are reasonable mechanisms in place to mitigate unexpected capital investment and operating costs. In addition, key IRM assumptions, including CPI and productivity factors, are reasonable
Satisfactory	IRM (four- to five-year framework)	The IRM period is four to five years
Below Average	IRM (six- to ten-year framework)	The IRM period is six to ten years
Poor	IRM (ten+ years)	The IRM period is over ten years

CONSIDERATION 6: POLITICAL INTERFERENCE

Definition

Political interference refers to political risk that could occur within a jurisdiction. Political interference could be in the following forms: (1) influence on the regulator's ability to independently and impartially arrive at a decision; (2) passing legislation to override a decision made by the regulator; and (3) the regulator being elected instead of being appointed.

Score	Definition
Excellent	- No government influence on the regulatory decision-making process - There has been no adverse legislation in the regulated utility sector - The regulator is appointed
Good	- Low degree of government influence on the regulatory decision-making process - There has been no adverse legislation in the regulated utility sector - The regulator is appointed
Satisfactory	- Low degree of government influence on the regulatory decision-making process - There has been no adverse legislation in the regulated utility sector - The regulator is appointed or elected
Below Average	- Modest degree of government influence on the regulatory decision-making process - There has been no adverse legislation in the regulated utility sector - The regulator is appointed or elected
Poor	- High degree of government influence on the regulatory decision-making process - There has been some adverse legislation in the regulated utility sector - The regulator is appointed or elected

Appendix: Regulation (CONTINUED)

CONSIDERATION 7: RETAIL RATE

Definition

Average price for residential customers (monthly consumption of 1,000 kilowatt hours (kWh). DBRS notes that this factor is not applicable for gas distribution, water and waste-water utilities.

Score	Item	Definition
Excellent	Below 8.00 cents	- Consistently below 8.00 cents per kWh - Strong economic environment
Good	8.00 cents to 10.99 cents	- Consistently in the 8.00 cents to 10.99 cents per kWh range - Strong economic environment
Satisfactory	11.00 cents to 13.99 cents	- Consistently in the 11.00 cents to 13.99 cents per kWh range - Very good economic environment
Below Average	14.00 cents to 16.99 cents	- Consistently in the 14.00 cents to 16.99 cents per kWh range - Good economic environment
Poor	17.00+ cents	- Consistently higher than 17.00 cents per kWh - Good economic environment

CONSIDERATION 8: STRANDED COST RECOVERY

Definition

Stranded costs occur when a utility has already incurred costs (F&PE, operating cost or capital spending) and faces uncertainty as to when it can recover these costs. In some cases, stranded costs are written off if it is certain that these costs cannot be recovered. DBRS looks at the following factors: (1) whether stranded costs exist and their magnitude; (2) the likelihood of recovery of stranded costs; (3) the frequency of writedowns; and (4) the time it takes to recover these costs.

Score	Item	Definition
Excellent	No Stranded Cost	No stranded costs associated with legitimate or reasonable costs incurred by utilities
Good	Full Recovery	- Some stranded costs exist - Stranded costs are fully recovered in a timely manner - No historical stranded cost writedowns
Satisfactory	Occasional Writedowns	- Some stranded costs exist - Stranded costs are recovered but subject to some regulatory lag - Occasional writedowns
Below Average	Frequent Writedowns	- Some stranded costs exist - Stranded costs are sometimes recovered - Frequent writedowns - Takes considerable time to recover costs
Poor	Frequent Significant Writedowns	- Significant stranded costs exist - Stranded costs are not fully recovered - Significant writedowns occur - Significant regulatory lag associated with the recovery

Appendix: Regulation (CONTINUED)

CONSIDERATION 9: RATE FREEZE

Definition

A rate freeze refers to a fixed retail rate that is charged to customers during a period of time (more than two years). During the rate-freeze period, utilities are exposed to increases in operating and energy costs. The longer the rate-freeze period or the more frequency with which a rate freeze occurs within a jurisdiction, the riskier it is for the utility.

Score	Item	Definition
Excellent	Never	• Rates are never frozen
Good	Potential	• Rates have the potential to be frozen
Satisfactory	Occasional	• Rates are occasionally frozen • The frozen period is less than three years
Below Average	Frequently	• Rates are frequently frozen • The frozen period is less than three years
Poor	Rate Freeze	• Rates are currently frozen • The frozen period is three years and longer

CONSIDERATION 10: MARKET STRUCTURE (DEREGULATION)

Definition

Market structure refers to the electricity, gas or water market functions within the regulatory regime. DBRS particularly focuses on whether the market is deregulated and to what degree the market has been deregulated. The strongest utilities will have fully-integrated operations (generation, transmission and distribution).

Score	Item	Definition
Excellent	Fully Regulated	• The market is fully regulated • Fully integrated utilities
Satisfactory	Partial Regulation	• The market is not fully regulated • Utilities are partially regulated • Good market structure, providing stability and low risk associated with purchased energy costs and counterparty risk
Poor	Fully Deregulated	• The market is fully deregulated • Market structure provides some risk with respect to purchased energy costs and counterparty risk



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Rating Report

Ontario Power Generation Inc.



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Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Unsecured Debt	A (low)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

On April 6, 2016, DBRS Limited (DBRS) confirmed the Issuer Rating and Unsecured Debt rating of Ontario Power Generation Inc. (OPG or the Company) at A (low), and the Commercial Paper (CP) rating at R-1 (low), all with Stable trends. The confirmation was largely based on the continuing financial support from the Company's shareholder, the Province of Ontario (the Province; rated AA (low) by DBRS). The Province, through its agent the Ontario Electricity Financial Corporation (OEFC; rated AA (low) by DBRS), provides most of OPG's financing (approximately 63% of total debt). The Company's remaining debt is in the form of non-recourse project finance debt.

The Province announced in January 2016 that OPG will be moving forward with the refurbishment of the Darlington Nuclear Generating Station (the Darlington Refurbishment). The project has a final budget of \$12.8 billion, and the refurbishment of the first unit is scheduled to begin in October 2016, with the last unit to be in-service by 2026. DBRS believes that given the complexity and scale of the Darlington Refurbishment, there is significant execution risk as well as the potential for cost overruns. The high capital expenditures (capex) required, albeit spread over a ten-year period, in addition to ongoing maintenance capex (total capex forecast of approximately \$2 billion for 2016), are expected to pressure OPG's key credit metrics. Although the Company's cash flow-to-debt and debt-to-capital ratios have remained strong, DBRS expects leverage to increase to approximately 40% during this period of high capex. Additionally, profitability for OPG continues to be challenged as evidenced by the

negative EBIT-interest coverage ratio for the year. DBRS notes that while the in-service of the Lower Mattagami River Project (LMRP) and the prescription of 48 previously unregulated hydroelectric facilities to regulated rates in late 2014 have helped improve OPG's EBITDA, the Company's reported corporate return on equity (ROE; 4.1% in 2015) remains far below the approved ROE of 9.3%. This has largely been due to the high cost base of OPG, which has resulted in several disallowances by the Ontario Energy Board (OEB) for the Company to recover forecasted compensation expenses.

OPG plans to submit a five-year application with the OEB later this year for new regulated rates effective 2017. The OEB has expressed that it expects prices for hydroelectric operations to be based on an incentive regulation (IR) ratemaking methodology, and that prices for nuclear operations be based on a multi-year forecast cost-of-service (COS) approach with IR features. DBRS believes that profitability for OPG could continue to be challenged following a switch to an IR framework, as the introduction of productivity and efficiency targets could further depress earnings. However, through its Business Transformation initiative, OPG has demonstrated its ability to improve efficiency by reducing regular headcount from continuing operations by approximately 2,700 personnel since 2011. Furthermore, earnings should also benefit from the growth in the rate base as Darlington Refurbishment pre-requisite projects are completed, and new regulated rates in 2017.

Financial Information

For the year ended December 31

(CAD millions)	2015	2014	2013	2012	2011
Cash flow/Total debt ¹	33.2%	27.0%	22.9%	20.8%	28.9%
Total debt in capital structure ^{1, 2}	35.9%	36.9%	38.9%	36.9%	36.8%
EBIT gross interest coverage (times) ³	(0.86)	0.24	(1.12)	0.66	0.02
EBITDA gross interest coverage (times) ³	2.89	2.75	2.21	3.15	2.71
(Cash flow - n.w.f.)/Total debt ⁴	27.5%	21.3%	16.5%	13.8%	21.1%

¹ Including operating leases. ² Adjusted for Accumulated Other Comprehensive Income. ³ Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.
⁴ Included nuclear waste funding (n.w.f.) payments as they are not discretionary.

Issuer Description

Ontario Power Generation Inc. is an electricity generating company with a diverse portfolio of over 17,000 megawatts (MW) of in-service generating capacity. The Company is wholly owned by the Province of Ontario.

Rating Considerations

Strengths

1. Support of shareholder (the Province)

The Province indirectly provides OPG with the majority of its long-term funding requirements through the OEFC, a government financing arm for the provincial power companies; however, this debt is not directly guaranteed by the Province. DBRS believes that the Province will continue to support its investment since OPG is a creation of the Province and is integral to fulfilling Ontario's energy needs.

2. Dominant market position in Ontario

OPG's importance in Ontario is demonstrated by the fact that it is the primary electricity generator in the Province, accounting for approximately 51% of electricity produced in Ontario in 2015.

3. Reasonable regulatory framework

The reasonable regulatory framework has allowed the Company to recover prudently incurred costs. However, DBRS notes that the unsuccessful appeal of the OEB's decision to disallow labour compensation costs related to OPG's nuclear operations has increased uncertainty regarding the Company's ability to fully recover its nuclear cost through future regulated prices (refer to the Regulation section for details).

4. Limited nuclear waste management liabilities

As a result of the Ontario Nuclear Funds Agreement (ONFA) with the Province, OPG's exposure relating to nuclear waste management liabilities has been capped at \$5.94 billion (in 1999 dollar terms) for the initial 2.23 million used fuel bundles produced. The Company is, however, responsible for the incremental costs related to the management of used fuel bundles in excess of 2.23 million bundles (2.44 million currently). The Province provides a guarantee for any shortfall between the value of the nuclear fund and the Canadian Nuclear Safety Commission consolidated financial guarantee requirement.

Challenges

1. Significant capex program

OPG has a significant capex program underway (approximately \$2 billion planned for 2016). The Company also faces significant execution risk associated with the Darlington Refurbishment because of the complexity and scale of the project. It is expected that OPG will not undertake any major capex without having financing and a cost-recovery mechanism in place, thus minimizing the financial risks.

2. Nuclear generation risks

Nuclear generation faces higher operating risks than other types of generation because of its complex technology (approximately 57% of OPG's production in 2015). Financial implications of forced outages, especially with older units (e.g., Pickering Nuclear Generating Station), are greater given the high fixed-cost nature of these plants as well as the fact that lost revenues resulting from outages are not recoverable through rates.

3. High cost base

OPG's high cost base has resulted in several disallowances by the OEB. In its decision on OPG's application for 2014 and 2015 rates, the OEB disallowed recovery of \$100 million of compensation costs for each of 2014 and 2015. Additionally, in September 2015, the Supreme Court of Canada upheld the OEB's 2011 decision to disallow \$145 million of forecast nuclear compensation costs for 2011 and 2012. DBRS believes that the inability of OPG to fully recover compensation costs in future regulated prices could have a negative impact on earnings and has affected the Company's ability to achieve its approved ROE. DBRS notes that OPG has been combatting this issue through its Business Transformation initiative, which has reduced headcount by over 2,700 since 2011.

4. Political intervention

OPG is subject to political intervention, largely because of changes in government mandates and policies as well as limits that restrict revenues and earnings should the price of electricity rise quickly. DBRS notes that the Province has committed to having OPG run more autonomously; however, the risk of further government intervention still exists.

Major Projects

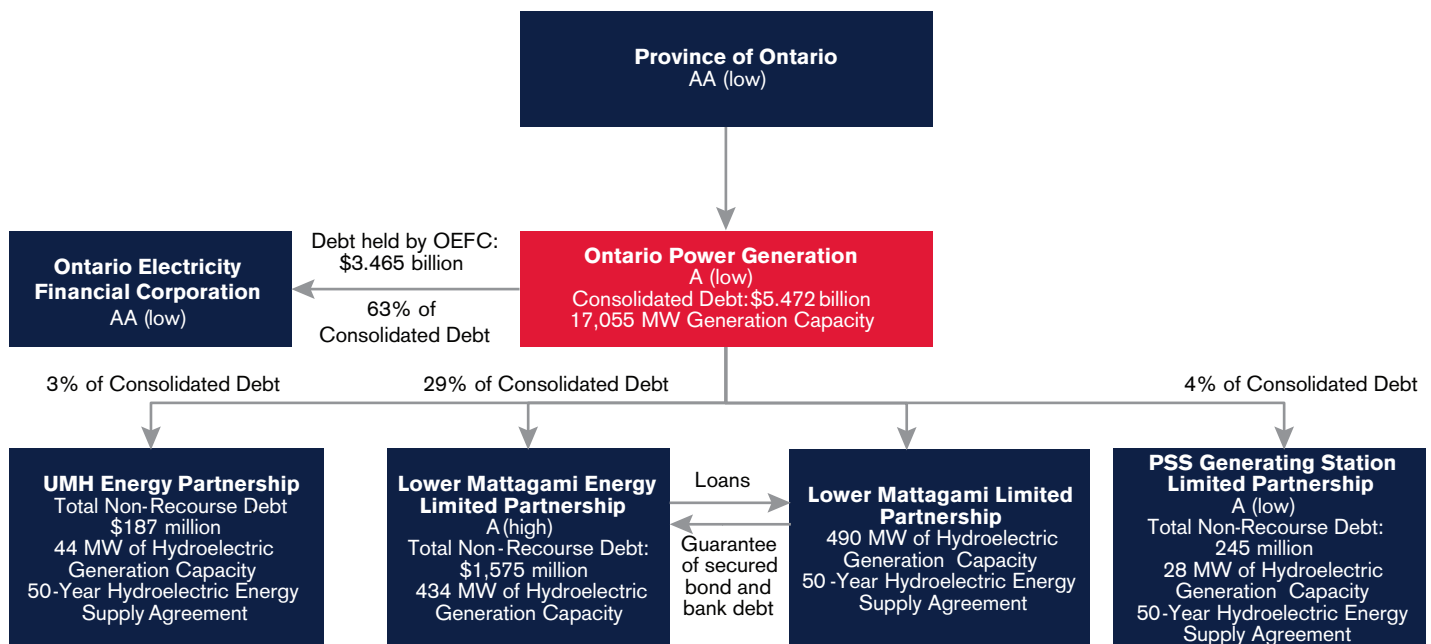
- **Darlington Refurbishment:** The Darlington Refurbishment will extend the operating life of the Darlington Nuclear Generating Station by approximately 30 years. The execution of the refurbishment for the first unit is scheduled to begin in October 2016, with the last unit scheduled to be completed by 2026.
- **Peter Sutherland Sr. Generating Station Project (PSS GS):** The PSS GS is a 28-MW hydroelectric station on the Abitibi River. The project has a 50-year hydro Energy Supply Agreement (ESA) with the Independent Electricity Systems Operator (IESO; rated A (high) by DBRS), which protects it from hydrology and power price risk. Additionally, OPG guarantees PSS GS's debt until the Recourse Release Date (see DBRS's PSS Generating Station LP (New Post Creek) rating report dated October 23, 2015, for more details).
- **Lower Mattagami River Project (LMRP):** All six units of the LMRP were placed in service as of December 31, 2014. This project, which increased the capacity of four generating stations on the Lower Mattagami River by 438 MW, has a 50-year hydroelectric ESA with the IESO, which provides a utility-like COS revenue requirement for energy produced. In addition, OPG guarantees LMRP's debt until the Recourse Release Date (see DBRS's Lower Mattagami Energy Limited Partnership (LMELP) rating report dated June 4, 2015, for more details).
- **Nanticoke Solar Facility:** OPG announced in March 2016 that it has been selected by the IESO to develop a 44-MW solar facility near the Nanticoke Generating Station. Construction will begin once the Company receives the required approvals and contracts.

Project	Estimated Cost (\$ millions)	Spent as of Dec. 31, 2015 (\$ millions)	In-Service Target Date
Darlington Refurbishment	12,800	2,166	2026*
Peter Sutherland Sr. Generating Station	300	95	H2 2017
Lower Mattagami River Project	2,600	2,484	June 2015**

* Four units with staged in-service. Last unit scheduled to be completed by 2026.

** Entire complex placed in-service by December 2014.

Simplified Organizational Chart

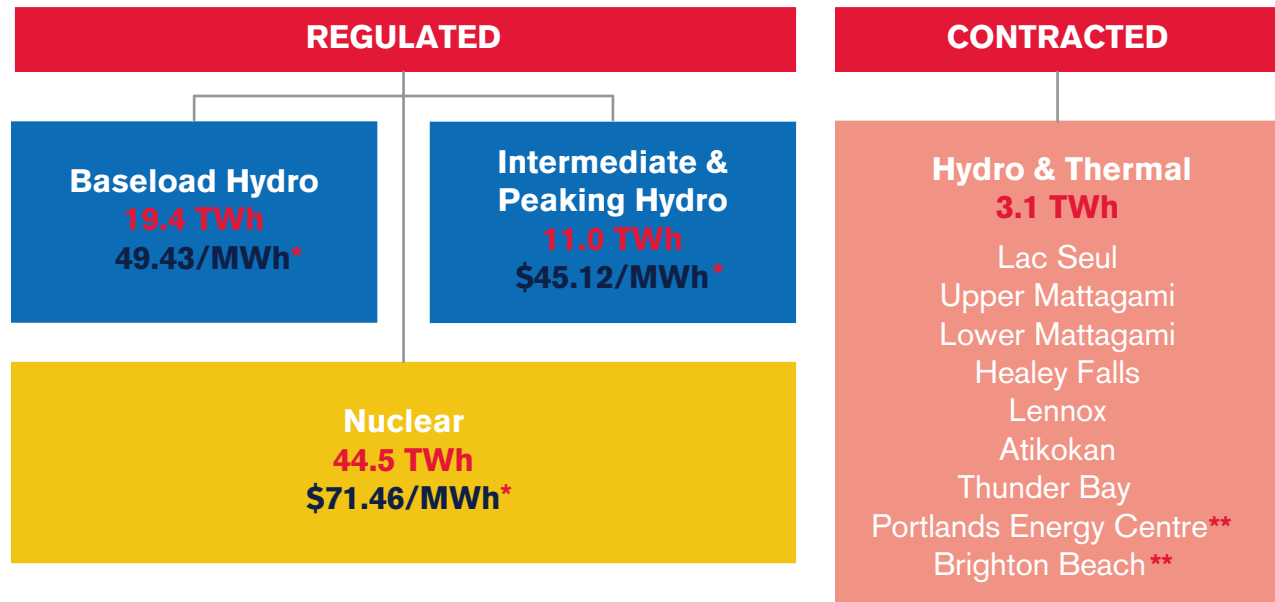


As of December 31, 2015.

Regulation

- OPG benefits from a reasonable regulated environment. As of December 31, 2015, 96% of its installed in-service capacity is regulated.
- OPG, regulated by the OEB under the *Electricity Restructuring Act, 2004 (Ontario)*, is allowed to receive regulated prices for all electricity generated from its nuclear facilities (6,606 MW) as well as most of its hydroelectric power facilities (6,428 MW).
- An amendment to Ontario Regulation 53/05 (O. Reg. 53/05) by the Ministry of Energy brought all of OPG's previously non-regulated hydroelectric facilities not under an ESA with the IESO to be subject to the OEB's regulation effective July 1, 2014. This amendment provided further stability to the Company's credit profile, as a large majority of installed in-service capacity is now regulated.
- In September 2015, the Supreme Court of Canada overturned the Court of Appeal and upheld the OEB's original decision to disallow a portion of the Company's nuclear compensation costs. DBRS believes that the inability of OPG to fully recover its nuclear compensation in future regulated prices could have a negative impact on earnings.
- The OEB issued its decision on OPG's application for Payment Amounts for Prescribed Facilities for 2014 and 2015 in November 2014, approving the following:
 - A 24-month revenue requirement of approximately \$8.1 billion for 2014 and 2015, a reduction of \$934 million from the requested amount.
 - Payment amounts effective November 1, 2014, of \$40.20/megawatt hour (MWh) for previously regulated hydroelectric facilities, \$41.93/MWh for newly regulated hydroelectric facilities and \$59.29/MWh for regulated nuclear facilities.
 - Payment riders for the recovery of OEB-authorized regulatory variance and deferral accounts of \$6.04/MWh for previously regulated hydroelectric facilities and \$1.33/MWh for regulated nuclear facilities, effective January 1, 2015.
 - Deemed capital structure of 55% debt, a change from 53%, with an ROE of 9.36% on regulated base rates for 2014.
- The OEB rejected the previous accrual method of accounting for pension and other post-employment benefit (OPEB) costs for 2014 and 2015 rate setting purposes. OPG will instead include pension and OPEB costs on a cash basis with a deferral account set up to account for the difference. This decreased the Company's revenue requirement by approximately \$600 million. A final position on the accrual or cash method will be determined based on a generic proceeding on pension and OPEB costs.
- Other significant outcomes from this decision included (1) a reduction of \$100 million of compensation costs in each of 2014 and 2015, (2) disallowance of \$88 million related to the Niagara Tunnel Project (\$77 million write-off for OPG with \$1,365 million approved for inclusion into rate base) and (3) a reduction in the revenue requirement of \$70 million from a regulatory tax loss in 2013.
 - OPG subsequently filed an application with the OEB to review and vary the decision in regards to the Niagara Tunnel Project disallowance. The OEB issued a decision in January 2016, reducing the disallowance to \$66 million.
- In December 2014, the Company filed an application to recover the balance in its deferral and variance accounts as of December 31, 2014. OPG was seeking to recover approximately \$1.3 billion through rate riders over the 18-month period from July 2015 to December 2016, and a further \$459 million in a future period.
 - The OEB approved a partial settlement in June 2015 for OPG to recover \$669 million from October 1, 2015, to December 31, 2016, and a further \$816 million in a future period.
 - Subsequently in September 2015, the OEB approved the Company's recovering the remaining applied-for \$263 million.
- OPG plans to file a five-year application with the OEB in 2016 for new regulated rates effective 2017. The OEB has expressed that it expects prices for hydroelectric operations to be based on an IR ratemaking methodology, while prices for nuclear operations be based on a multi-year forecast COS approach with IR features.

OPG's Price Structure



* Rates as of January 1, 2016.

** 50% ownership interest.

For the year ended December 31, 2015.

- OPG sells electricity to consumers through the IESO.
- Regulated operating divisions sell at rates set by the OEB, which include rate riders used for the recovery of nuclear deferral and hydroelectric variance account balances.
- The Contracted Generation Portfolio operating division primarily sells electricity at prices set through ESAs or other long-term contracts with the IESO.

Earnings and Outlook

For the year ended December 31

(CAD millions)	<u>2015</u>	<u>2014</u>	<u>2013</u>	<u>2012</u>	<u>2011</u>
Revenues	5,476	4,963	4,863	4,732	4,964
EBITDA ¹	848	826	638	841	699
EBIT ¹	(252)	72	(325)	177	5
Gross interest expense	293	300	289	267	258
Earning before taxes ¹	(407)	36	(373)	86	(114)
Net income before non-recurring items ¹	(271)	88	(261)	115	48
Reported net income	402	804	135	367	338
Return on equity	-2.8%	1.0%	-3.2%	1.5%	0.6%
Hydroelectric rate base	7,490	7,526	4,829	3,744	3,772
Nuclear rate base	3,659	3,707	3,780	4,133	3,859
Approved regulated ROE	9.30%	9.36%	9.55%	9.55%	9.43%
Achieved regulated ROE	N/A	6.31%	0.46%	4.73%	4.80%

¹ Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.

2015 Summary

- EBITDA in 2015 increased largely because of (1) higher rates approved by the OEB for the regulated segments, including for the 48 hydroelectric facilities that began receiving regulated rates as of November 1, 2014, (2) the in-service of all units of the LMRP in December 2014 and (3) the conversion to biomass for the Atikokan and Thunder Bay generating stations.
 - The increase was offset by higher operating expenses and lower nuclear generation as a result of the four-unit Darlington Vacuum Building Outage, which reduced generation by 3.6 TWh.
- EBIT decreased significantly because of a \$346 million increase in depreciation and amortization. The increase was because of (1) lower depreciation in 2014 caused by higher amounts deferred for that year, (2) higher amortization of regulatory assets and liabilities as OPG began recovering approximately \$1.8 billion in its regulatory variance and deferral accounts and (3) higher depreciation following the in-service of the LMRP and the biomass conversion projects.
- Profitability for OPG remains challenged, as the Company achieved a reported corporate ROE of 4.1% for the year,

significantly below the approved ROE of 9.30%. DBRS notes that the lower ROE is partly due to the Company's capitalization at around 35% debt versus the regulatory capital structure of 55% debt.

2016 Outlook

- EBITDA is expected to remain stable in 2016, as the majority of earnings are expected to continue to be from regulated operations.
- While earnings should benefit from higher rate riders in effect for 2016, net income before non-recurring items is expected to remain weak. Additionally, as the Darlington Refurbishment enters the execution stage, earnings will be negatively affected as each generating unit is temporarily removed from service (first unit in October 2016).
- Earnings volatility going forward will come from (1) adjustments to rate base determined by the OEB and (2) macro factors such as weather, unexpected outages and Ontario's economic conditions.

Financial Profile

	For the year ended December 31				
(CAD millions)	2015	2014	2013	2012	2011
Net income before non-recurring items 3	(271)	88	(261)	115	48
Depreciation & amortization	1,100	754	963	664	694
Deferred income taxes and other	1,097	730	616	305	693
Cash flow (bef. working cap. changes)	1,926	1,572	1,318	1,084	1,435
Nuclear waste funding	(361)	(351)	(383)	(380)	(422)
Dividends paid	0	0	0	0	0
Capital expenditures	(1,376)	(1,545)	(1,568)	(1,427)	(1,145)
Free cash flow (bef. working cap. changes)	189	(324)	(633)	(723)	(132)
Changes in non-cash working cap. items	(100)	212	239	172	166
Net free cash flow	89	(112)	(394)	(551)	34
Long-term investments	(180)	0	0	24	0
Proceeds on asset sales	3	0	0	0	7
Net equity change	0	0	0	0	0
Net debt change	(33)	165	543	310	334
Other	(25)	(5)	0	0	(14)
Change in cash	(146)	48	149	(217)	361
Total debt	5,697	5,730	5,657	5,114	4,804
Cash & equivalents	464	610	562	413	630
Cash flow/Total debt 1	33.2%	27.0%	22.9%	20.8%	28.9%
Total debt in capital structure 1, 2	35.9%	36.9%	38.9%	36.9%	36.8%
EBIT gross interest coverage (times) 1, 3	(0.79)	0.29	(1.05)	0.71	0.12
(Cash flow - n.w.f.)/Total debt 4	27.5%	21.3%	16.5%	13.8%	21.1%
Dividend payout ratio	0.0%	0.0%	0.0%	0.0%	0.0%

1 Including operating leases. **2** Adjusted for Accumulated Other Comprehensive Income. **3** Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.
4 Included nuclear waste funding (n.w.f.) payments as they are not discretionary.

2015 Summary

- OPG's debt-to-capital and cash flow-to-debt ratios were strong for the current rating category; however, the Company's EBIT-interest coverage ratio remained weak.
- Cash flow from operations increased because of higher cash receipts from generation following the prescription of the 48 previously non-regulated hydroelectric facilities for regulated rates, and the in-service of the LMRP and biomass conversion projects.
- Capex of \$1.4 billion was lower following the completion of the above-mentioned projects. This was offset by construction starting on the PSS GS and continued work for the Darlington Refurbishment project.
- No dividend payments were made to the Province during this period of high capex requirements.
- OPG generated positive free cash flow in 2016, as cash flow from operations were sufficient to cover all expenditures.
- The Company repaid a \$500 million note to the OEFC by using cash on hand. PSS GS issued \$245 million of bonds,

of which \$180 million was invested in a structured deposit note with staggered maturity dates. Debt issued by PSS GS, which is guaranteed by the Company, will become non-recourse to OPG once the project is completed and certain requirements are met.

2016 Outlook

- OPG has planned capex of \$2 billion for 2016, including approximately \$1 billion for the Darlington Refurbishment project.
- As the Company continues to execute its large capex program, DBRS expects OPG to generate a free cash flow deficit in 2016. This deficit is expected to be financed with debt and cash on hand. As a result, leverage is expected to increase to nearly 40% over the next few years. DBRS expects the Company to maintain its strong debt-to-capital and cash flow-to-debt ratios in order to offset the weaker EBIT-interest coverage ratio.
- DBRS expects the Province to continue to forego dividends during the Company's large capex program.

Long-Term Debt Maturities and Credit Facilities

Long-term Debt

As at December 31, 2015

(CAD millions)	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>Thereafter</u>	<u>Total</u>
Long-term Debt	273	1,103	398	368	663	2,667	5,472
	5%	20%	7%	7%	12%	49%	100%

Maturity Profile

- The majority of the long-term debt issued at the parent level (approximately \$3.465 billion) is held by the OEFC, which is wholly owned by the Ontario government. As a result, DBRS does not expect any material refinancing risk.
- The Company's maturity profile is fairly spread out over the next five years. A modest maturity is expected in 2017 when \$900 million of senior notes held by the OEFC come due; however, refinancing risk is expected to be manageable.
- In October 2015, PSS GS issued senior secured bonds totalling \$245 million with a maturity date of 2067 and an effective interest rate of 4.90%.

Credit Facilities as at December 31, 2015 (CAD millions)

Bank facilities	Maturity	Amount	Outstanding	Available
Committed credit facility - Tranche 1	20-May-20	500	0	500
Committed credit facility - Tranche 2	20-May-20	500	0	500
Short-term uncommitted credit facilities	Demand	456	384	72
Short-term uncommitted overdraft facilities	Demand	25	0	25
Lower Mattagami River Project - Tranche 1	17-Aug-20	300	225	75
Lower Mattagami River Project - Tranche 2	17-Aug-16	200	0	200
UMH Energy Partnership credit facilities	15-Oct-15	16	14	2
UMH Energy Partnership overdraft facilities	15-Oct-15	8	0	8
Total		2,005	623	1,382

Liquidity

- OPG has a reasonable liquidity profile.
- The Company has a \$1 billion CP program backed by two tranches of bank facilities (extended due dates of May 20, 2020). All committed bank facilities were unused as at December 31, 2015.
- As at December 31, 2015, OPG had issued \$384 million of letters of credit, of which about \$345 million was attributed to its supplementary pension plan.
- The Company has separate credit facilities provided by the OEFC for corporate and project financing, which DBRS views as adequate for working capital purposes.

Company Profile

Generation Portfolio

As at December 31, 2015

	Percent %	Capacity (MW)
Nuclear		
Darlington	21%	3,512
Pickering A	6%	1,030
Pickering B	12%	2,064
	39%	6,606
Thermal		
Atikokan (Biomass)	1%	205
Thunder Bay (Biomass)	1%	153
Portlands Energy Centre 1	2%	275
Brighton Beach 1	2%	280
Lennox (Dual oil & gas)	12%	2,100
	18%	3,013
Hydroelectric		
Contracted 2	6%	1,006
Regulated	38%	6,428
	44%	7,434
Other (Wind) 3	0%	2
Total Capacity	100%	17,055

1 Represents OPG's share of in-service generation. **2** Includes plants under an ESA or a long-term contract with the IESO. **3** One wind-power turbine.

- OPG is the largest generator of electricity in Ontario.
- In 2015, OPG generated 78.0 terawatt hours of electricity with total in-service capacity of 17,055 MW on December 31, 2015.
- OPG partnerships consist of the following:
 - OPG and ATCO Power Canada Ltd. co-own the Brighton Beach Generating Station, a 580-MW natural gas-fired generating station.
 - OPG and TransCanada Energy Ltd. jointly own the Portlands Energy Centre, a 550-MW natural gas-fired generating station.
 - OPG owns the Bruce A and Bruce B nuclear generating stations, which are leased on a long-term basis to Bruce Power Limited Partnership.
 - OPG and the Lac Seul First Nation (LSFN) jointly own the Lac Seul Generating Station, with LSFN owning 25% of the facility.
 - OPG and the Moose Cree First Nation (MCFN), through its wholly owned subsidiary Amisk-oo-Skow Finance Corporation, jointly own the Little Long, Harmon, Kipling and Smoky Falls generating stations, with MCFN owning 25% of the facilities.

Ontario Power Generation Inc.

Balance Sheet

	Dec. 31				Dec. 31		
(CAD millions)	2015	2014	2013		2015	2014	2013
Assets				Liabilities & Equity			
Cash & equivalents	464	610	562	S.T. borrowings	225	0	32
Accounts receivable	545	482	402	Accounts payable	1,228	1,151	1,026
Inventories	440	428	485	Current portion L.T.D.	273	503	5
Regulatory assets	628	167	306	Regulatory liabilities	26	5	16
Prepaid expenses & other	313	161	224	Deferred revenue & other	78	36	26
Total Current Assets	2,390	1,848	1,979	Total Current Liab.	1,830	1,695	1,105
Net fixed assets	20,595	17,593	16,738	Long-term debt	5,199	5,227	5,620
Intangibles	98	76	59	Deferred income taxes	890	828	565
Nuclear removal/waste mgmt. funds	15,121	14,354	13,471	Pension & post-retirement benefits	5,682	6,620	5,369
Regulatory assets	5,279	7,024	5,094	Nuclear removal/waste mgmt. funds	20,169	17,028	16,257
Investments, materials & other	819	750	750	Regulatory liabilities	0	0	0
				Payables & other L.T. liab.	487	780	841
				Shareholders' equity	10,045	9,467	8,334
Total Assets	44,302	41,645	38,091	Total Liab. & SE	44,302	41,645	38,091

For the year ended December 31

Balance Sheet & Liquidity
& Capital Ratios

	2015	2014	2013	2012	2011
Current ratio	1.31	1.09	1.79	1.91	1.62
Total debt in capital structure	36.2%	37.7%	40.4%	39.3%	38.6%
Total debt in capital structure 1, 2	35.9%	36.9%	38.9%	36.9%	36.8%
Cash flow/Total debt	33.8%	27.4%	23.3%	21.2%	29.9%
Cash flow/Total debt 1	33.2%	27.0%	22.9%	20.8%	28.9%
(Cash flow - dividends)/Capex (times)	1.40	1.02	0.84	0.76	1.25
(Cash flow - n.w.f.)/Total debt 4	27.5%	21.3%	16.5%	13.8%	21.1%
Dividend payout ratio	0.0%	0.0%	0.0%	0.0%	0.0%

Coverage Ratios (times)

EBIT gross interest coverage 3	(0.86)	0.24	(1.12)	0.66	0.02
EBIT gross interest coverage 1, 3	(0.79)	0.29	(1.05)	0.71	0.12
EBITDA gross interest coverage 3	2.89	2.75	2.21	3.15	2.71
Fixed-charges coverage 3	(0.86)	0.24	(1.12)	0.66	0.02

Profitability Ratios

EBITDA margin 3	15.5%	16.6%	13.1%	17.8%	14.1%
EBIT margin 3	-4.6%	1.5%	-6.7%	3.7%	0.1%
Profit margin 3	-5.0%	1.8%	-5.4%	2.4%	1.0%
Return on equity 3	-2.8%	1.0%	-3.2%	1.5%	0.6%
Return on capital 1, 2, 3	-0.8%	1.4%	-1.0%	1.6%	1.3%

1 Including operating leases. **2** Adjusted for Accumulated Other Comprehensive Income. **3** Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.
4 Included nuclear waste funding (n.w.f.) payments as they are not discretionary.

Rating History

	Current	2015	2014	2013	2012	2011
Issuer Rating	A (low)	A (low)	A (low)	A (low)	A (low)	NR
Unsecured Debt	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Previous Action

- Confirmed March 24, 2015.

Commercial Paper Limit

- \$1 billion.

Previous Report

- Ontario Power Generation*, Rating Report, March 24, 2015.

Notes:

All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrs.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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Research

Assessing U.S. Investor-Owned Utility Regulatory Environments

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Assessing U.S. Investor-Owned Utility Regulatory Environments

Regulatory advantage is the most heavily weighted factor when S&P Global Ratings analyzes a regulated utility's business risk profile. One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions where a utility operates. A utility management team's skill in dealing with regulatory risk can sometimes overcome a difficult regulatory environment. Conversely, companies' regulatory risk can increase even with supportive regulatory regimes if management fails to devote the necessary time and resources to the important task of managing regulatory risk. We modify our assessment of regulatory advantage to account for this dynamic in our ratings methodology (for the criteria we use to rate utilities, see "Corporate Methodology," and "Key Credit Factors For The Regulated Utilities Industry," published Nov. 19, 2013, on RatingsDirect.)

There are specific factors we use in the U.S. to assess the credit implications of the numerous regulatory jurisdictions here that help us determine the "preliminary regulatory advantage" in our credit analysis of each investor-owned regulated utility. We organize the subfactors of regulatory advantage into four categories:

- Regulatory stability,
- Tariff-setting procedures and design,
- Financial stability, and
- Regulatory independence and insulation.

Regulatory Stability

The foundation of our opinion of a jurisdiction is the stability of its approach to regulating utilities, encompassing transparency, predictability, and consistency. Given the maturity of the U.S. investor-owned utility industry, the long history of utility regulation (going back to the early 20th century) and the well-established constitutional protections accorded to utility investments, we emphasize the principle of consistency when weighing regulatory stability. We also incorporate the degree to which the regulatory framework either explicitly or implicitly considers credit quality in its design.

Regulatory Change Can Bring Stability, Or Take It Away

While stability is one of the four pillars of our approach to evaluating regulatory risk, experience shows us that it's not an absolute positive or negative for creditors. Change can boost or lessen risk, and any improvement in a regulatory regime will overcome any negative connotations of instability. A good example is Michigan, which in about 2008 revamped its whole approach to utility regulation. As implemented in subsequent years by the Michigan Public Service Commission, the reforms have almost completely transformed the regulatory environment in that state.

However, during any period of change, we see the uncertainties surrounding the process and the outcome as possible major causes of risk. A more recent and still ongoing example is New York, where the Public Service Commission's (NYPSC) Reforming the Energy Vision (REV) proceeding is possibly revving up risk for utilities. While the NYPSC seemed at first to be focusing more on high-minded policy questions than on making a lot of changes to day-to-day operations, the current phase could eventually disrupt the way utilities make money and affect their ability to earn the authorized return. If the end result is greater operating risk with no opportunity to earn greater returns, our assessment of the regulatory environment could change.

Durability of regulatory system

An established, dependable approach to regulating utilities is a hallmark of a credit-supportive jurisdiction. Creditors lend capital to utilities over long periods to fund the development of long-lived assets. A firm understanding of the basic "rules" that will govern how the utility will recover its costs, including servicing its debt and the return on its capital over an extended period, is essential to accurately assess credit risk. Major or frequent changes to the regulatory model invariably raise risk due to the possibility of future changes. Steady application of transparent, comprehensible policies and practices lowers risk.

How long a regulatory framework has been in place is the most important factor in this area. We view jurisdictions as most supportive when there have been no major changes or where the approach has been consistent for a long time and is not prone to further changes. Jurisdictions that have undergone a major, fundamental change in the regulatory paradigm that seems to be working well are a little less supportive, and less so a jurisdiction that is transitioning to a new regulatory approach. Credit risk rises if the transition attracts political attention. The less-supportive jurisdictions are those that frequently alter the basic regulatory approach. We also view the framework's development less favorably if policy disputes or legal actions cause contention, indicating that the political consensus regarding utility regulation is fragile.

Some jurisdictions permit competitive markets to prevail for some important functions of the delivery of utility services, notably wholesale markets for electricity and retail markets for electric or gas service. In others, vertical integration is the norm. A jurisdiction's credit-supportiveness is more prone to suffer if market forces directly influence major cost items that utilities could otherwise control through cost-based regulation because of the potential volatility it creates. The risk inherent in a market-based model is straightforward: utility rates are more volatile when markets influence them rather than fully embedded costs, and regulators are apt to resist full and timely recovery when market price changes are abrupt and substantial (and perhaps misunderstood). We observe less support for credit quality in jurisdictions that are in the midst of deregulating important parts of the utility framework. The uncertainty of the timing

of reaching the outcome--and what the result will be--is a negative factor from a credit perspective. Utilities are also prone to financial stress when the transition to competition causes potential "rate shock" for customers that regulators could resist.

Transparency of regulatory framework and attitude toward credit quality

We believe regulation works best when it is rule-based. Creditor interests are better protected by the presence of and adherence to a pre-set code of rules and procedures that we can look to when assessing risk. Risk is lower when the rules are more transparent and when they take into account a utility's financial integrity. We regard jurisdictions that require regulators to protect utilities' financial soundness and have transparent policies and procedures as the most credit-supportive. We ascribe higher risk in jurisdictions where policies and procedures support financial integrity, but where inconsistency can selectively arise. We believe a jurisdiction provides even less support when transparency merely exists. We see less support when any of these credit factors are absent, or if the regulator's record on following precedent is poor.

Tariff-Setting Procedures

We review rate decisions as part of our surveillance on each U.S. utility. We focus on the jurisdiction's overall approach to setting rates and the process it uses to establish base rates (practices pertaining to separate tariff provisions for large expenses are in the "Financial Stability" part of our analysis). We focus on whether base rates, over time, fairly reflect a utility's cost structure and allow a fair opportunity to earn a compensatory return that provides creditors with a financial cushion that supports credit quality. If the process is geared toward an incentive-based system, our analysis centers on the risks related to the incentive mechanisms. If the jurisdiction has vertically integrated utilities, we review the resource procurement process and assess how it affects regulatory risk.

Rate Cases Can Affect Creditworthiness

Although not common, rate case outcomes can sometimes lead directly to a change in our opinion of creditworthiness. Often it's a case that takes on greater importance because of the issues being litigated. For example, in 2010, we downgraded Florida Power & Light and its affiliates following a Florida Public Service Commission rate ruling that attracted attention due to drastic changes to settled practices on rate case particulars like depreciation rates. More recently, in June 2016, we downgraded Central Hudson Electric & Gas due to our revised opinion of regulatory risk. While that reflected the company's own management of regulatory risk, it was prompted in part by other rate case decisions in New York that highlighted the overall risk in the state.

Sometimes change comes from outside the usual rate case process. The aforementioned improvement in Michigan (see the previous sidebar) came from legislative changes that reformed rate case procedures such as interim rate increases and time limits on rate decisions. In March 2016, we affirmed our ratings on Entergy Corp. and kept the outlook positive based on the prospect of lower regulatory risk as the company pursues strategic changes in its various jurisdictions. For instance, legislation in Arkansas allowing for formula rates could better enable Entergy to manage regulatory lag and earn its authorized return.

Ability to timely recover costs

We review authorized returns and capital structures in our analysis, but we focus mainly on actual earned returns. Examples abound of utilities with healthy authorized returns that have no meaningful expectation of earning those returns due to, for example, rate case lag (i.e., the relationship between approved rates and the age of the costs used to set those rates) or expense disallowances. Also, the stability of the returns is as important as the absolute level of financial returns, and we note the equity component in the capital structure used to generate the revenue requirement in rate proceedings. Higher authorized and earned returns and thicker equity ratios translate into better credit measures and a more comfortable equity cushion for creditors. We consider a regulatory approach that allows utilities the opportunity to consistently earn a reasonable return as a positive credit factor.

A very credit-supportive jurisdiction is one in which all of the utilities it regulates consistently earn above-average returns. We assess jurisdictions lower if only some of them do, and lower still if the earnings records are below average or highly variable from year to year. We deem jurisdictions as weaker when all utilities earn well-below-average returns, and we consider jurisdictions where all utilities consistently earn exceedingly poor returns, including years with negative returns, as weakest.

We consider "regulatory lag" along with the record of earned returns to assess timeliness. Credit-supportive jurisdiction typically have a track record of little regulatory lag, indicating that responsibility for a poor or uneven earnings history lies more with management than its regulators. In addition to the regulator's efficiency in completing rate cases, we consider the obsolescence of the costs on which the rates are based, the timing of interim rates, and other practices (such as allowing rates to automatically change in a future period based on inflation) that affect a utility's ability to earn its authorized return.

If a jurisdiction uses incentives as the primary ratemaking tool and institutes a comprehensive incentive program that allows revenues and costs to diverge, we evaluate the incentive mechanisms' effect on a utility's earnings capability and stability. A common approach features an extended period between base rate reviews, during which rates change according to a formula based on inflation, a predetermined productivity factor, and capital spending. An incentive-based program can be close to credit-neutral compared with systems that permit more frequent and dynamic rate changes if the risk is symmetrical (i.e., an equal opportunity to earn over or under the authorized return and equivalent reward or penalty for doing so) and limited (a maximum or minimum earnings band). The effect on regulatory risk depends on whether we believe the efficiency targets are realistic and achievable, the regulator's treatment of disparities in actual versus authorized spending, and the framework's flexibility to adjust returns for capital market conditions. If there are operating standards, we determine whether they fairly reward or punish utilities if performance deviates from expectations.

There is a muted effect on regulatory risk in jurisdictions where incentives are not central, but are instead used only to augment cost-of-service regulation. A moderate amount of incentives that carry symmetrical risks can even modestly support better credit quality. For example, a fuel-adjustment and purchased-power clause with a sharing mechanism that affects less than 10% of the total fuel costs and cuts both ways when commodity markets change can modestly reduce risk by offering the utility a mild incentive for effective procurement and efficient operations, without unduly exposing it to commodity price risk.

We typically view jurisdictions as credit-supportive if regulators use symmetrical incentive mechanisms sparingly in the rate-setting process. When incentives play a larger role in the rate-setting approach, but are well-designed to evenly allocate risk, we see less support for credit quality. We regard still lower jurisdictions where incentives dominate and are poorly designed. Jurisdictions where incentives significantly degrade risk and are part of a comprehensive incentive regime harbor the most risk for creditors.

Financial Stability

When we evaluate U.S. utility regulatory environments, we consider financial stability to be of substantial importance. Cash takes precedence in credit analysis. A regulatory jurisdiction that recognizes the significance of cash flow in its decision-making is one that will appeal to creditors.

Creative Ratemaking Can Help...If Used Correctly

The ability of financial stability factors to help a utility maintain and smooth its cash flow gives prominence to this area of our analysis. In addition to the near-ubiquitous fuel clauses, we see utilities give more attention to obtaining so-called "disc" mechanisms (DSIC, for distribution system investment charge, is a common acronym for this kind of rate adjustment) that accelerate and stabilize cash flow realization when a utility pursues a strategy of boosting rate base to fuel earnings growth.

For instance, Duquesne Light recently filed for a DSIC mechanism in Pennsylvania in conjunction with a long-term plan to improve its distribution system. Approval, requested for October, would enhance our view of Duquesne's ability to manage regulatory risk, because it would consequently be joining the other Pennsylvania utilities that already benefit from this mechanism. On the other end of the spectrum, Mississippi Power's ongoing travails in obtaining rate relief for its Kemper coal-fired plant, which has experienced significant cost and schedule problems, points to how regulatory risk can deteriorate under stress when well-established procedures for handling large and risky capital projects are absent or not followed.

Treatment of significant expenses

When utilities have major expenses such as fuel and purchased power/gas/water, the presence of separate tariff provisions to facilitate full and contemporaneous recovery is the most prominent factor in this part of our analysis. The timely adjustment of rates in response to changing commodity prices and other expenses that are largely out of management's control is a key feature of a credit-supportive regulatory jurisdiction. The analysis centers on the special tariff mechanisms to determine their effectiveness in producing the cash flow stability they are designed to achieve. The frequency of rate adjustments, the ability to quickly react to unusual market volatility, and the control of opportunities to engage in hindsight disallowances of costs could affect our analysis almost as much as whether the tariff provisions exist at all. The record of disallowances plays a part when we assess regulatory advantage.

We consider jurisdictions to be very credit-supportive if utilities can recover all high-expense items through an automatic tariff clause that is based on projected costs, adjusts frequently, and has no record of any significant disallowances. We see more risk if separate mechanisms exist, but lack some of the above features. We view jurisdictions that lack independent rate mechanisms for large expenses and have a record of significant disallowances

as weakest.

Treatment of capital spending

When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.

Very supportive jurisdictions offer a separate recovery mechanism for all capital spending, a mandated current cash return during construction, and a bonus return for some or all capital projects. We deem a jurisdiction weaker if there is a separate mechanism for only certain kinds of spending and the cash return and higher return are subject to the regulator's discretion. We view jurisdictions that don't allow separate recovery or a current return as being lower on the scale. We assess a jurisdiction as weaker still when it doesn't have independent rate mechanisms for capital projects, and we view it as most risky when full recovery occurs only after a utility's assets become operational.

Cash-smoothing mechanisms

We have a more positive view of jurisdictions that use innovative regulatory provisions that help to smooth cash flow from period to period. For a jurisdiction that focuses on incentives in its basic approach to ratemaking, through multiyear rate plans or a formula rate plan, we view the availability of "reopeners" (to adjust rates for unexpected events out of the utility's control) as key to this part of our analysis. The utility's ability to petition for a rate increase when unexpected or uncontrollable costs arise in the midst of a long-term rate plan is a critical risk mitigant.

Other examples of risk-dampening regulatory policies include hedging program approvals, and decoupling (the separation of a utility's profits from sales) or weather-related mechanisms. If a utility seeks approval of a hedging program to manage exposure to commodity prices, it can reduce risk if there's a clearly stated hedging policy that its regulator has endorsed, and a track record of activity that conforms to the policy that has not been subject to regulatory second-guessing. A well-designed decoupling or weather-normalization mechanism that efficiently adjusts rates to offset the sales effect of economic conditions, customer usage trends, or weather will soften earnings and cash flow volatility to the benefit of creditors. If applicable, we view a record of regulatory responsiveness to extreme events for utilities that are prone to violent or disruptive weather (like hurricanes) as favorable for credit quality.

A jurisdiction is more credit-supportive if it makes extensive use of extraordinary and credit-supportive rate mechanisms. Also favorable are jurisdictions that use innovative mechanisms selectively, or have regulators that are receptive to reopeners where incentives are the main ratemaking method.

Regulatory Independence And Insulation

The role of politics in U.S. utility regulation is often misunderstood. In most jurisdictions, the regulator's function is to set and regulate rates and service standards with due regard not only for the interests of those who advance the capital needed to provide safe and reliable utility service, but for other constituents as well. Creditors should recognize that utility regulation harbors political as well as economic risks. Therefore, how politics could influence regulation helps us evaluate a regulatory environment.

Political Influence On Utility Regulation Can Yield Unexpected Results

This is often the most variable area of our analysis and the most difficult to assess. The most dramatic, fairly recent reminder of how political forces can influence regulatory risk was last year's unexpected reversal by the popularly elected Mississippi Supreme Court of a significant rate increase granted for Mississippi Power to help pay for a major power plant under construction. Regulators, who were ordered to roll back rates and issue refunds, struggled to make decisions amid the strained political atmosphere and extra scrutiny that the Court's action had created. The episode also highlighted the greater regulatory risk that attends jurisdictions that expose regulators (and in this case the appellate court) to direct political accountability.

Another more recent example of political influence on regulation underscores the complexity of this area of analysis, because it featured many participants at both the federal and state level. Electric utilities in Ohio had a credible strategy for dealing with rising competitive risks in their merchant generation portfolios by offering the output to retail customers at pre-set prices on a long-term basis, which the state regulator approved. The federal regulator (Federal Energy Regulatory Commission, or FERC), responding to complaints by other generators that the plan would inhibit the operation of the competitive electricity market, essentially overruled the Ohio regulators and blocked the utilities from pursuing the strategy that would have reduced its risk profile. It essentially decided that its political interest in and ideological commitment to efficient electricity markets overrode the state's political interest in stable electric rates. The saga is still continuing with attempts to bypass the FERC's ruling through other means, but no matter what the ultimate result, we see how political considerations can increase risk.

Political independence of regulator

The primary factor in this part of our analysis is the regulators' (and, when relevant, the judicial body that reviews the regulators' decisions) political independence. We think it's more credit-supportive when the regulator is substantially independent of the political process. Jurisdictions are somewhat less favorable when insulation is strong, such as when the executive branch of government appoints regulators subject to legislative approval. We consider jurisdictions to be further down the scale when the same voters who pay utility bills directly elect the regulators, but institutional efforts have been made to erect some shield for regulators from transient political concerns. We view jurisdictions that arrange for direct political accountability of regulators that persistently influences regulatory decisions as less supportive.

Record of direct political intervention

The overall atmosphere that a regulator operates in can affect its ability to deliver sound, fair, and timely rate decisions and set prudent regulatory policies that assist utilities in managing business and financial risk. In this part of our

evaluation, we may consider the tone that politicians set, the history of political insulation given to the regulatory body and the courts that review its actions, and the behavior of important constituencies that intervene in utility proceedings. We also track the public visibility of utility issues, because we believe that the likelihood of constructive regulatory behavior increases with the comparative obscurity of utility issues.

We view a jurisdiction as having a lower risk if the regulatory environment is marked by cooperative attitudes and constructive interventions in important matters before the regulator. We assess a jurisdiction lower when the atmosphere is more combative and restricts the regulator's ability to act in the long-term best interests of all parties. We consider jurisdictions as weaker if the regulatory environment is so infused with short-term political influence over regulatory decisions that the regulator can't effectively consider investor interests in its decisions.

Related Criteria And Research

Related Criteria

- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013

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Board Staff Interrogatory #18

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Ref: Exh C1-1-1/Attachment 1

In its evidence, Concentric asserts that OPG's risk will increase over the 2017-2021 plan term as it is moving from a regime whereby OPG's payment amounts were set through a two-year cost of service methodology to one where the rates will be set for a five-year period and through an incentive regulation regime for the regulated hydroelectric generation assets.

While OPG's payment amounts have been set in the previous three applications based on a two-year cost of service approach, in each instance, there was an additional "bridge" year between the applications where there was no resetting or adjustment to the payment amounts in that year. In effect, approved payment amounts were only changed every three years.

- a) Please provide Concentric's views as to whether OPG's payment amounts have not been sufficient or have otherwise increased OPG's business risk due to OPG deciding to stay out for an additional year before applying for cost of service-based payments.
- b) Please provide Concentric's views on the role of existing deferral and variance accounts to mitigate revenue and cost risks during the years that OPG has stayed out before reapplying for new cost of service-based payments.

Response

The following response has been provided by Concentric:

- a) As described in Concentric's report, (Ex. C1-1-1, Attachment 1, at page 3), Concentric's analysis of OPG's business risk focused on changes to the Company's risk profile since EB-2013-0321, as well as how that risk profile may further change over the time period for which payment amounts are being set in this proceeding. In performing that analysis, Concentric did not identify OPG's decision to stay out an additional year before applying for cost of service-based payments as representing a source of greater or less risk as compared to OPG's risk profile as of EB-2013-0321.
- b) Existing deferral and variance accounts have mitigated revenue and cost risks related to the specific revenues and costs reflected in those accounts, relative to the risk level that would exist if there were no such deferral and variance accounts.

Board Staff Interrogatory #19

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Ref: Exh A1-3-2

Ref: Exh C1-1-1 Attachment 1 pages 3-4, 24-26

On page 8 of Exh A1-3-2, OPG states:

With the Niagara Tunnel Project now in service, OPG's regulated hydroelectric generation facilities are in a relatively stable, steady state that is conceptually consistent with a price-cap index form of IR. The company believes that, of the three options set out in the RRFE, the 4GIRM approach is best suited to the state of its regulated hydroelectric generation facilities.

On page 3 of Exh C1-1-1 Attachment 1, Concentric states:

Specifically, in Concentric's view, there is an anticipated change in risk related to OPG's hydroelectric facilities that is attributable to the transition from a two- year cost of service rate-setting term to a five-year incentive regulation ("IR") regime.

Concentric provides its analysis on regulatory risk, specifically related to adoption of incentive regulation, on pages 24-26 of Exh C1-1-1. Concentric points to an analysis by DBRS, and further states, on page 26:

The incentive regulation plan will be proposed for a term of five years (2017-2021) and does not include a proposal to rebase costs in 2017. As a result, costs last approved by the OEB in 2014 will provide the basis for OPG's payment amounts through 2021. Under the proposed hydroelectric IR plan, OPG will be exposed to the risk that costs deviate from the price cap over the five-year rate period. In addition to the decoupling of revenues from costs, the hydroelectric IR plan will differ from OPG's traditional regulatory framework in that rates will be established for a five-year period, whereas, OPG's cost of service rates have traditionally been set for significantly shorter periods of time (two years or less).

Concentric concludes on page 26:

Consistent with DBRS' findings regarding the increased level of risk a utility faces with relatively longer incentive rate plans, discussed above, OPG's planned five-year rate-setting proposals expose the Company to material incremental risk relative to the two-year cost-of-service rate periods established in EB-2007-0905, EB-2010-0008 and EB-2013-0321.

- 1
2 a) What quantitative evidence does Concentric have that incentive regulation, subject to
3 periodic reviews to rebase (reset) rates and given the existence of deferral and
4 variance accounts and other mechanisms to mitigate rate impacts or the need for
5 reviews and off-ramps subject to the forms of incentive regulation adopted by the
6 OEB for electricity and natural gas distribution sectors, has resulted in increased
7 operational risk for electricity and gas distribution utilities compared to the forms of
8 regulation that they were subject to? Has this risk changed as experience with
9 incentive regulation has been gained by both the OEB and regulated utilities?
10
11 b) With respect to the first quote from page 26 of Concentric's evidence, can Concentric
12 confirm that, since OPG became subject to economic regulation by the OEB, OPG's
13 rate applications have been for 2-year test periods and that OPG has remained on an
14 additional year without any rate adjustments before refilling for its next two-year test
15 period cost of service-based payments application.
16
17 c) What evidence does Concentric have that OPG has been exposed to "risk" of cost
18 under-recovery due to staying out for an additional year before re-filing?
19
20 d) How has Concentric taken into account, both qualitatively and quantitatively, the
21 ancillary aspects of OPG's proposed hydroelectric IRM plan, such as existing and
22 proposed deferral and variance accounts, accessibility to incremental capital modules,
23 reporting and off-ramp mechanisms, in assessing how OPG is exposed to material
24 increased risk during the proposed 5-year hydroelectric plan?
25
26 e) Please provide Concentric's reasons supporting its views of increased and material cost
27 recovery risk for OPG going into the five-year hydroelectric IRM plan, as stated on pages
28 3 and 26 of Concentric's evidence, in contrast to OPG's evidence on page 8 of Exh A1-3-
29 2, quoted above, that its hydroelectric operations are in a steady-state situation given
30 operationalization of the Niagara Tunnel consistent with a price cap for incentive
31 regulation, and that OPG felt that the 4-GIRM (Price Cap IR) form was best suited for its
32 current (expected) hydroelectric operations.
33
34

35 Response
36

37 The following response has been prepared by the Concentric Energy Advisors
38

- 39 a) Concentric has not studied, attempted to quantify, or relied upon an assessment of the
40 impacts of incentive regulation adopted by the OEB for electricity and natural gas
41 distribution sectors in relation to their prior forms of regulation. Concentric's risk
42 assessment is based on the relative shift in risk from OPG's existing regulatory
43 framework to that proposed for the hydroelectric facilities, the general assessments of
44 credit rating agencies of utility incentive regulation programs vs. cost of service, and the
45 relative risk of OPG in relation to the peer group. Please also see the response to Ex. L-
46 3.1-001 Staff-13.

- 1
2 b) OPG's first rates application to the OEB was EB-2007-0905. In that proceeding, the
3 Board approved the revenue requirements and payment amounts for April 1, 2008 to
4 December 31, 2009. This rate was continued without adjustment for an additional 14
5 months until the rates in EB-2010-0008 for 2011 and 2012 were approved by the OEB
6 effective March 1, 2011. These rates then continued for an additional 22 months without
7 adjustment until the rates for 2014 and 2015 were approved in EB-2013-0321. The
8 payment amounts from EB-2013-0321 effective November 1, 2014 are what OPG
9 continues to collect today.
10
11 c) The cited text in this interrogatory (from Concentric's evidence page 3) refers to the
12 forward five-year rate plan period and the test period the OEB has used to set payment
13 amounts for OPG on a cost of service basis, not the stay out year: "Under the proposed
14 hydroelectric IR plan, OPG will be exposed to the risk that costs deviate from the price
15 cap over the five-year rate period" (Ex.C1-1-1 Attachment 1, p. 26). A decision not to
16 apply to re-establish rates at the end of a test period is a separate and subsequent
17 decision that is not related to the risk associated with the ratemaking methodology itself.
18 Nonetheless, for any period where a regulated utility does not match its expected costs
19 with expected revenues it is exposed to the risk of cost under-recovery.
20
21 d) Concentric has considered the specific provisions of the proposed hydroelectric plan in
22 determining that it increases OPG's risk in relation to its prior cost of service plan.
23 Addressing each of the specifically mentioned "ancillary" elements of OPG's proposed
24 hydroelectric rate plan:
25 • Variance accounts – the Company proposes the same variance and deferral
26 accounts as currently exist, with the exception of the proposed variance account to
27 adjust for the requested change to the common equity ratio (Exhibit A1, Tab 3,
28 Schedule 2, page 7 of 54). This does not therefore represent a change in risk.
29
30 • Incremental Capital Module – OPG is proposing a standard ICM available upon
31 application. Based on the materiality threshold which applies to the ICM, and the non-
32 discretionary criterion, the ICM is unlikely to be triggered, and if it is, only those
33 amounts over the materiality threshold are eligible for recovery. (See: EB-2006-0170,
34 Filing Requirements for Electricity Transmission and Distribution Applications, June
35 28, 2012, pp. 6-8, Chapter 3, pp. 6-8).¹ In Concentric's view, this represents a greater
36 risk of capital cost under-recovery than the current cost of service approach.
37
38 • Performance Reporting and Off-ramps – the proposed 300 basis point ROE off-ramp
39 provides the opportunity to initiate a regulatory review when actual earnings fall

¹ In 2011, the Board revised its Filing Requirements for Electricity Transmission and Distribution Applications to clarify the ICM specifications on how to calculate the incremental capital amount that may be recoverable when a distributor applies for an ICM. In the Filing Requirements issued in June 2012, the ICM was further revised to remove words such as "unusual" and "unanticipated" as prerequisites to an application for incremental capital, although the requirement that the proposed expenditures be non-discretionary remains. Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, P. 18.

1 below, or above that level. Since the 300 basis point trigger applies to all of OPG's
2 ratebase and allowed ROE, this would require a significant earnings shortfall from the
3 hydroelectric business prior to being triggered. It is therefore unlikely that a deviation
4 in revenues in relation to actual costs would be sufficient to trigger a review under the
5 off-ramp.

6
7 There is no guarantee that the I -X price cap will track actual costs; in fact, the
8 expectation is that it will not, creating the incentive to control costs. The specific
9 exceptions associated with the price cap, the ICM and off-ramp provisions, both have
10 substantial materiality provisions that require the company to absorb risk until these
11 thresholds are reached. These plan parameters, in conjunction with the 5-year term,
12 place OPG at greater risk than under its predecessor cost of service programs.
13

- 14 e) These views are not inconsistent. OPG's characterization of its regulated hydroelectric
15 facilities as being in a "relatively stable, steady state" is reflected in Figure 1, p. 16 of
16 Concentric's evidence. OPG's hydroelectric rate base increased from \$3.9 billion in 2008
17 to \$7.5 billion in 2015, and is projected to grow only gradually to \$7.7 billion by 2021.
18 This relatively flat rate base profile lends itself to the proposed I-X framework. This is not
19 to say, however, that an I-X framework is less risky than cost of service. Over the course
20 of five years, unforeseen events could drive additional capital or operating expenditures
21 that may or may not be covered under ICM or Z factor exceptions. As described above
22 and in response to Ex. L-3.1-001 Staff-13, the performance based rate plan entails
23 greater risk for OPG.

Board Staff Interrogatory #20

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

3.1-Staff-20

Ref: Decision with Reasons EB-2010-0008, pages 116-118

Ref: Report of the Board on Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets (EB-2012-0340), issued March 18, 2013

Ref: Exh C1-1-1

Ref: Exh I1-1-1 and Attachment 1 Revenue Requirement Work Form

In OPG's application for 2011-12 payments, the issue of technology-specific costs of capital (i.e., separate costs of capital for each of hydroelectric facilities and nuclear facilities, based on different risks for the two types of generation) was considered. While it has been generally accepted in all previous payment amount applications that nuclear generation is generally more risky than hydroelectric generation, OPG's cost of capital for regulated generation assets has been set in aggregate. In the Decision with Reasons EB-2010-0008, the OEB concluded that there was inadequate quantitative evidence to establish technology-specific costs of capital for each of hydroelectric and nuclear generation.¹ Thus in all payment order applications to date, OPG's cost of capital has been set on a common basis for all prescribed generation assets. The only real difference is that the cost of capital and the deemed capital structure for nuclear are set on the prescribed nuclear assets less the adjustment for the lesser of the unfunded nuclear liability or asset retirement obligations.

In the current application, there is a bifurcated approach for the rate setting for nuclear and regulated hydroelectric generation assets.

¹ Decision with Reasons EB-2010-0008, March 10, 2011, pages 116-8.

a) Please confirm that the cost of capital explicitly reflected in the going-in hydroelectric payments (i.e., before the application of the first price cap adjustment for 2017), even with the proposed adjustments, would reflect the cost of capital approved in EB-2013-0321. In the alternative, please explain.

b) The cost of capital that is implicitly reflected in the hydroelectric payments "rates" will change every year in accordance with the fact that the price cap adjustment, and specifically the inflation component reflects changes in input prices, which include

1 inflation on labour, material and capital equipment prices and the cost of financing (i.e.,
2 cost of capital), as the OEB has explicitly concluded in past policy.² Please confirm
3 OPG's understanding that changes in the cost of capital are reflected, implicitly, through
4 the price cap adjustment, even if an explicit decomposition of what the changed cost of
5 capital parameters is not easily demonstrated.

- 6
- 7 c) For the payments for the nuclear assets, OPG has proposed that the cost of capital be
8 set for nuclear at the outset of the plan. The forecasted weighted average cost of long-
9 term debt varies by year, while the return on equity (ROE) and short-term debt rates and
10 the capital structure are fixed over the five year term. This is demonstrated on sheet 4
11 "OEB Adjustment Sheet" of the Revenue Requirement Work Form (RRWF). Further, OPG
12 has proposed a variance account that would track the revenue requirement impact
13 between the forecast ROE approved in the decision to this application (initially proposed
14 at 9.19%) and the ROE as annually updated in accordance with the OEB's policy on the
15 cost of capital³ for 2018 to 2021. This explicitly means that the cost of capital
16 explicitly varies on an annual basis. Please confirm.

17

18 ² Further, for hydroelectric, any difference in the revenue requirement between the current 45% equity thickness
19 and that determined by the OEB in its decision to this application, and which OPG has proposed to be 49%,
20 would be tracked for later disposition.

21 ³ Currently Report of the Board on the Cost of Capital for Ontario's Rate-regulated Utilities, (EB-2009-0084),
22 December 11, 2009.

23

24

25 **Response**

- 26
- 27 a) OPG confirms that the cost of capital reflected in the going-in hydroelectric payment
28 amounts reflects the cost of capital approved in EB-2013-0321.
- 29
- 30 b) OPG agrees that the cost of capital that is implicitly reflected in the hydroelectric
31 payments "rates" will change every year in accordance with the price cap adjustment.
32 OEB staff emphasized this point during the stakeholder consultation and, as a result,
33 OPG eliminated from the application a proposed variance account which was intended to
34 record differences in hydroelectric ROE during the IR term. However; the price cap
35 adjustment only reflects changes in the cost of financing based on the capital structure
36 embedded in the base rate. To the extent the capital structure changes going forward,
37 and that change impacts the base rate, OPG does not agree that the annual price cap
38 adjustment reflects OPG's financing costs. To address this, OPG has requested the
39 Hydroelectric Capital Structure Variance Account to capture the revenue requirement
40 impact of the difference between the 45 per cent equity/55 per cent debt capital structure
41 approved by the OEB in EB-2013-0321 and the capital structure approved in this
42 proceeding.
- 43

1 c) Confirmed. OPG's 2017-2021 revenue requirements as proposed include the OEB's 9.19
2 per cent ROE as published in the OEB's October 15, 2015 letter. OPG has proposed to
3 track the revenue requirement impact of the difference between the ROE approved by
4 the OEB for the nuclear business in this proceeding as part of the revenue requirements
5 for 2018-2021 and the actual annually updated ROE specified by the OEB (Ex. H1-1-1, p.
6 31).

7
8 The nuclear payment amounts are based on a custom incentive regulation framework
9 and do not have the implicit adjustment to cost of capital associated with an annual price
10 cap adjustment.

Board Staff Interrogatory #21

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Ref: Exh C1-1-1 Attachment 1, pages 18-26

Pages 18-23 of Exh C1-1-1 Attachment 1 provide Concentric's qualitative assessments in which it concludes that OPG's operational, regulatory and political risk with respect to the nuclear generation assets increases, while acknowledging that there are some mitigating factors with respect to OPG's approach to project planning and management of the DRP and the provisions of O.Reg. 53/05 effective January 1, 2016.

Pages 24-26 of Exh C1-1-1 Attachment 1 provide Concentric's qualitative assessments of OPG's rate proposals. In particular, on the middle of page 26, Concentric describes the nuclear rate smoothing proposal and how the variance between revenues and revenue requirement will be tracked in the rate smoothing deferral account per O.Reg. 53/05.

Nonetheless, Concentric concludes on page 26:

Consistent with DBRS' findings regarding the increased level of risk a utility faces with relatively longer incentive rate plans, discussed above, OPG's planned five-year rate-setting proposals expose the Company to material incremental risk relative to the two-year cost-of-service rate periods established in EB-2007-0905, EB-2010-0008 and EB-2013-0321.

²Further, for hydroelectric, any difference in the revenue requirement between the current 45% equity thickness and that determined by the OEB in its decision to this application, and which OPG has proposed to be 49%, would be tracked for later disposition.

³ Currently [Report of the Board on the Cost of Capital for Ontario's Rate-regulated Utilities, \(EB-2009-0084\)](#), December 11, 2009.

The discussions on pages 18-23 and on page 26 are fully qualitative in nature. With respect to the nuclear rate setting proposal, please indicate how Concentric has translated the qualitative points on these pages to conclude that, as a result, OPG is exposed to "material incremental risk" over the 2017-2021 plan period.

Response

The following response has been prepared by Concentric Energy Advisors:

In regard to the pages of Concentric's report referenced in the interrogatory, and as further discussed in Concentric's report, there are generally five major risk areas related to regulated utility nuclear power generation, including: (1) the ability to implement large and complex projects on time and on budget; (2) increases in costs and/or outage durations related to emerging safety regulations (e.g., Fukushima-response costs); (3) age-related degradation of station components, discovery of unexpected conditions and/or extended outage durations that put nuclear plants at further risk of producing lower-than-forecasted power; (4) decommissioning of retired nuclear plants and long-term management of used nuclear fuel and other nuclear waste, including the cost and timing of decommissioning work and the ability to fund that work; and (5) the ability to recover costs, including a return, in a timely manner.

Concentric evaluated OPG's risk factors in key risk areas, as described further in Exhibit C1-1-1/Attachment 1, at pages 18 to 23. Based on that evaluation, Concentric concluded that:

- The Darlington Refurbishment Project presents an incremental source of risk to the Company that will become increasingly significant during the upcoming rate-setting period. Specifically, as discussed in Concentric's report, the DRP is a significant undertaking, as the \$12.8 billion cost of the project represents over 100% of OPG's total regulated rate base as of EB-2013-0321 (i.e., the rate base most recently approved by the Board), and approximately 70% of OPG's overall net in-service property, plant and equipment ("PP&E") balance (both prescribed and non-regulated). Relative to the size of the Company, the DRP is one of the most significant undertakings in the North American nuclear industry in the recent past. As further demonstrated in Concentric's report, the DRP is considerably larger, relative to OPG's size, than two other nuclear megaprojects that are currently ongoing in North America;
- OPG's plans to pursue extended Pickering operations beyond 2020 also poses considerable risks;
- OPG also faces risks due to degradation of Darlington's primary heat transport pump motors;
- OPG continues to face risks related to the implementation of new safety and regulatory requirements;
- OPG's forecasts for nuclear costs and generation levels are being made in the face of this uncertainty, while also covering a longer, five-year term.

With regard to the nuclear smoothing proposal specifically, Concentric noted in its report that the proposal involves the deferred recovery of a substantial portion of the OEB-approved revenue requirement until after the end of the Darlington Refurbishment Project. As shown

1 in Exhibit A1-3-3 Page 2, under OPG's rate smoothing proposal the Company will defer \$1.6
2 billion, or nearly 10% of the nuclear revenue requirement, through 2021. That will decrease
3 cash flow relative to what it would be absent smoothing. This deferral of revenue and
4 reduced cash flow will occur during a period in which OPG forecasts issuing \$4 billion in
5 debt, and the maintenance of credit support is critical (see, Exhibit A1-3-3 page 4).
6 Incremental increase in financial risk arises, in part, due to inherent uncertainty related to the
7 collection of amounts deferred for a decade into the future (see, Exhibit C-1-1/Attachment 1,
8 at 28).

9
10 From a business risk perspective, the risks discussed in the Concentric report and
11 summarized above could manifest themselves in terms of variability in cash flows and
12 earnings that impact the ability of OPG to recover its costs. That variability in cash flows and
13 earnings could occur through either changes in cost levels or changes in generation levels
14 (or both). In Concentric's opinion, the combination of the factors described in the Concentric
15 report and summarized above could lead to significant variability in cash flows and earnings,
16 and thus, in conjunction with the increasing proportion of nuclear power in OPG's generation
17 mix, combine to create material incremental risk for the Company.

18 From an investor's perspective, the business risk assessment process is inherently
19 qualitative in nature and involves the application of reasoned judgment on the part of the
20 analyst. In fact, the business risk analyses performed by credit ratings agencies such as
21 S&P, Moody's, and DBRS are largely qualitative in nature as well. For instance, the ratings
22 agencies stress the importance of factors such as the quality, consistency and predictability
23 of the regulatory regime in which a utility operates, and the types of businesses in which a
24 utility engages (e.g., transmission and distribution vs. generation). In addition, Concentric's
25 comparative risk analysis, presented in Exhibit C1-1-1 Attachment 1, pages 30 through 41, is
26 used in conjunction with Concentric's business risk assessment of OPG to provide context
27 for where, within a reasonable range, OPG's equity ratio should be set by the Board. Based
28 on the combination of those analyses, Concentric concluded that an equity ratio of no less
29 than 49% was appropriate for OPG.

AMPCO Interrogatory #15

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Ref: C1-1-1 Page 1 Chart 1

a) Please extend the table to include the years 2013 to 2016.

Response

a) See Ex. L-03.1 VECC-5, Attachment 1, Table 5.

AMPCO Interrogatory #16

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Ref: C1-1-1- Page 1

a) Please provide the annual impact on revenue requirement if the current capital structure is maintained.

Response

The annual impact on the Nuclear revenue requirement if the current capital structure is maintained is provided in Attachment 1.

See Ex L-1-9.8 Staff-217 for the expected entry into the Hydroelectric Capital Structure Variance Account.

Numbers may not add due to rounding.

Filed: 2016-10-26
EB-2016-0152
Exhibit L
Tab 3.1
Schedule 2 AMPCO-016
Attachment 1
Table 1

Table 1
Calculation of Cost of Capital Using Current and Proposed Capital Structure (\$M)

Line No.	Description	2017	2018	2019	2020	2021
		(a)	(b)	(c)	(d)	(e)
1	Nuclear Rate Base¹	3,344.4	3,513.9	3,449.8	7,494.0	7,959.1
2	ROE²	9.19%	9.19%	9.19%	9.19%	9.19%
3	Cost of Debt²	4.91%	4.63%	4.56%	4.52%	4.51%
4	Deemed Equity (Proposed)²	49%	49%	49%	49%	49%
5	Deemed Debt (Proposed)²	51%	51%	51%	51%	51%
6	Proposed WACC³	7.0%	6.9%	6.8%	6.8%	6.8%
7	Deemed Equity (EB-2013-0321)	45%	45%	45%	45%	45%
8	Deemed Debt (EB-2013-0321)	55%	55%	55%	55%	55%
9	Proposed WACC (At EB-2013-0321 Capital Structure)⁴	6.8%	6.7%	6.6%	6.6%	6.6%
10	Revenue Requirement (Proposed)⁵	284.5	293.9	287.4	622.7	660.8
11	Revenue Requirement (At EB-2013-0321 Capital Structure)⁶	274.6	283.2	276.7	599.5	636.1
12	Revenue Requirement Impact if EB-2013-0321 Capital Structure is Maintained⁷	(9.8)	(10.7)	(10.6)	(23.2)	(24.7)

Notes

- 1 Ex. B1-1-1 Table 2, line 7 minus the Adjustment for Lesser of UNL or ARC from Ex. C1-1-1 Tables 1-5, line 7
- 2 C1-1-1 Tables 1-5
- 3 Calculated as: (Line 2 X Line 4) + (Line 3 X Line 5)
- 4 Calculated as: (Line 2 X Line 7) + (Line 3 X Line 8)
- 5 (Line 1 x Line 6) + (Line 1 x Line 2 x Line 4) x (tax rate / 1- tax rate), where the tax rate is 25%
- 6 (Line 1 x Line 9) + (Line 1 x Line 2 x Line 7) x (tax rate / 1- tax rate), where the tax rate is 25%
- 7 (Line 11 - Line 10)

CCC Interrogatory #11

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Reference: Ex. A2/T2/S1/p. 4

The evidence states:

"While OPG believes that the forecast credit metrics and operating cash flows in the 2016-2018 Business Plan will support investment grade credit rating, a different outcome of this application, including with respect to the nuclear rate smoothing trajectory, could result in a weaker financial position and increase the risk of a credit rating downgrade during a period of increased borrowing."

- a. Please explain, specifically, how a different outcome regarding rate nuclear rate smoothing could result in a weaker financial position for OPG.

Response

The statement cited in the question refers to the fact that an approved smoothed nuclear rate that is lower than proposed by OPG in this application (and reflected in OPG's 2016-2018 Business Plan) would reduce OPG's cash flow, increase debt, weaken key financial metrics, and increase the risk of a negative effect on the company's credit rating relative to business plan forecasts.

CCC Interrogatory #12

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Reference: Ex. C1/T1/S1/p. 2

OPG is proposing to establish the Hydroelectric Capital Structure Variance Account to record the revenue requirement impact of the difference between the capital structure approved by the OEB in this proceeding and the capital structure of 45% equity and 55% debt approved by the OEB in EB-2013-0321. What would be the impact in each year of the test period on the revenue requirement and the payment amounts for the hydroelectric business if OPG was required to maintain the 45% equity level embedded in the current revenue requirement?

Response

The requested 2017 hydroelectric payment amount is based on the capital structure (i.e., 45% equity) approved in EB-2013-0321. OPG is not proposing to modify the revenue requirement or payment amounts for the hydroelectric business to reflect the proposed 49% equity level during the 2017-2021 term. As discussed in Ex. H1-1-1, Section 6.4, OPG proposes establishing the Hydroelectric Capital Structure Variance Account to record the hydroelectric revenue requirement impact of the difference between the capital structure approved by the OEB in this proceeding and the capital structure approved by the OEB in EB-2013-0321 that underpins the hydroelectric payment amounts.

In response to L-09.8-1 Staff-217, OPG has provided the approximate amounts that would be recorded in the proposed Hydroelectric Capital Structure Variance Account if the OEB approves a capital structure of 49% equity and 51% debt in this application.

CCC Interrogatory #13

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Reference: Ex. C1/T1/S1/pp.3-4

OPG is proposing that for the years 2018 to 2021, the ROE will be set annually using the prevailing ROE specified by the OEB in accordance with the OEB's Cost of Capital Report. In addition, OPG is proposing that the revenue requirement impact of the variance between the forecast ROE and approved for 2018 to 2021 in this Application and the actual ROE that the OEB will specify annually for 2018 to 2021 will be recorded in the proposed Nuclear Variance Account. From the Council's perspective OPG's proposal is not clear. Is OPG proposing annual adjustments to the revenue requirement based on the OEB's Report – that will be used to set the annual payment amounts or is OPG seeking recovery of the variances through the proposed variance account at a later date? When does OPG propose that the variances in this account be cleared?

Response

As discussed in Ex. H1-1-1, Section 6.3, OPG proposes establishing the Nuclear ROE Variance Account to record the nuclear revenue requirement impact of the difference between the return on equity (ROE) approved by the OEB for the nuclear business in 2018 to 2021 in this proceeding as part of the revenue requirements for those years and the actual annually updated ROE specified by the OEB.

OPG proposes that the year-end balance in this account would be included in the application for disposition of balances to be filed in Q1 of 2019 as discussed in Ex. A1-3-3. Any future impacts would be included in an application for disposition of balances along with any other deferral and variance account balances as appropriate.

CCC Interrogatory #14

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Reference: Ex. C1/T1/S1/Attachment 1

Concentric Energy Advisors Inc. (Concentric) has provided a report regarding the appropriate cost of capital for OPG:

- a. Was the Concentric work subject to an RFP process? If not, why not? If so, please provide the RFP and the Terms of Reference for the Concentric work. What is the budgeted cost of that work and how is it to be recovered? How much has been billed to date with respect to the Concentric contract?
- b. Please provide a complete list of all of the work Concentric has done for the OEB and any Ontario utilities over the past 10 years; and
- c. Please provide a complete list of the work this Concentric team has done with respect to assessing the appropriate cost of capital for companies with nuclear businesses.

Response

- a. The Concentric work was not subject to an RFP process. There are a limited number of firms that have expertise in the subject area and after considering them, OPG decided to have discussions with Concentric. From the discussions with Concentric it was clear that they have deep expertise in the area and that they would be able to communicate their opinions clearly, objectively and in a manner helpful to the OEB. The budgeted cost of the work through the filing of Concentric's report was US\$104,000. The amount billed to date is \$268,000. Costs billed in the test period are sought to be recovered in rates but not the costs referenced herein.

Parts b) and c) of this response were prepared by Concentric Energy Advisors

- b. OPG understands by this question that CCC requests a complete list of the work Concentric has done for the OEB and Ontario utilities related to cost of capital, capital structure and the rate of return on equity. This is set out below. If CCC is seeking a different list, OPG declines to answer as other work done by Concentric for the OEB and Ontario utilities is not relevant to Issue 3.1.

Year	Primary Client	Engagement Name	Project Description
2007	Hydro One Enersource Hydro Mississauga Inc. Horizon Utilities Corp Hydro Ottawa Ltd PowerStream Inc. Toronto Hydro Veridian Connections Inc.	Ontario Coalition of Large Distributors	Compared recent ROE awards in jurisdictions outside of Ontario to those awarded by the Ontario Energy Board for electricity utilities in the Province.
2007	Ontario Energy Board	OEB ROE Gas Report	Conducted a detailed analysis of differences between ROE's for Ontario's gas utilities and those elsewhere in Canada, the U.S. and select foreign countries.
2008	Ontario Power Generation	Ontario Power Generation	Evaluated the possible risk premium associated with developing, constructing and owning a new nuclear power plant that was under consideration by OPG on a standalone basis.
2009	Enbridge Gas Distribution	Enbridge Cost of Capital Comments to OEB	Provided written comments on behalf of Enbridge to the Ontario Energy Board in response to the Board's invitation to interested stakeholders to provide comments to help the Board better understand whether current economic and financial market conditions have an impact on the reasonableness of the Cost of Capital parameter values calculated in accordance with the Board's established Cost of Capital methodology.
2009	Hydro One	Hydro One Cost of Capital Comments to OEB	Provided written comments on behalf of Hydro One and the Coalition of Large Distributors to the Ontario Energy Board in response to the Board's invitation to interested stakeholders to provide comments to help the Board better understand whether current economic and financial market conditions have an impact on the reasonableness of the Cost of Capital parameter values calculated in accordance with the Board's established Cost of Capital methodology.
2011	Enbridge Gas Distribution	Enbridge Capital Structure	Provided regulatory support services in determining the Company's appropriate level of equity thickness for inclusion in Enbridge's 2013 rate application.
2016	Torlys LLP/Ontario Power Generation	OPG Cost of Capital	Prepared an independent report as to whether the application of the cost of capital approved by the Ontario Energy Board in EB-2013-0321 is an appropriate basis for setting OPG's nuclear and regulated hydroelectric payment amounts in OPG's next Payment Amounts Application.

- c) Concentric has assessed the cost of capital in expert testimony and reports for companies with nuclear businesses in the following instances.

Year	Primary Client	Engagement Type	Project Description
2006, 2008, 2009, 2010, 2012, 2014, 2016	Northern States Power Company	Cost of Capital	ROE Testimony in Minnesota, North Dakota, South Dakota and Wisconsin on behalf of Northern States Power.
2014	Southwestern Public Service	Cost of Capital	ROE Testimony in Texas on behalf of Southwestern Public Service.
2016	Torys LLP/Ontario Power Generation	Cost of Capital	Prepared an independent report as to whether the application of the cost of capital approved by the Ontario Energy Board in EB-2013-0321 is an appropriate basis for setting OPG's nuclear and regulated hydroelectric payment amounts in OPG's next Payment Amounts Application.

In addition, Concentric has performed numerous consulting engagements where the assessment of the appropriate cost of capital for companies with nuclear businesses was integral to our scope of work. Those determinations of the appropriate cost of capital for nuclear businesses were made in the context of assessing the appropriate discount rate for purposes of nuclear facility appraisals, litigation involving nuclear plant valuations, evaluations of new nuclear construction, and mergers and acquisitions activity surrounding nuclear plants.

The table below contains examples of Concentric's nuclear engagements in which Concentric has assessed the cost of capital for companies with nuclear businesses.

Year	Primary Client	Engagement Type	Project Description
2002 – 2009	Six Nuclear Power Plant Owners	Litigation Support	Provided litigation support and expert testimony to clients in six separate legal proceedings before the U.S. Court of Federal Claims on the government's breach of the Standard Contract for spent nuclear fuel disposal.
2003, 2004, 2006, 2007	Multiple clients	Nuclear Plant Sales	Expert testimony regarding the valuation and sale of the following nuclear plants: Ginna (in New York, on behalf of Rochester Gas & Electric), Duane Arnold (in Iowa, on behalf of Interstate Power and Light), Palisades (in Michigan, on behalf of Consumers Energy Company, and Point Beach (in Wisconsin, on behalf of Wisconsin Electric Power Company).

Year	Primary Client	Engagement Type	Project Description
2006, 2009, 2010, 2013	FirstEnergy	Appraisal	Provided appraisals of certain FirstEnergy nuclear generating facilities to support the appeal of the company's property tax.
2007, 2008, 2010	Confidential Client	Strategic Advisory	Provided overviews of U.S. nuclear industry for a European client on multiple occasions. The report covered cost trends, status of new nuclear development, regulating trends, and hurdles, as well as emerging technology developments.
2007 through 2014	Confidential International New Nuclear Investors	Strategic Advisory	Provided strategic and financial advisory support to an international diversified conglomerate considering possible financial investments in proposed new nuclear generating stations in the U.S. Concentric also provided assistance to a major international nuclear technology vendor considering investing in new nuclear units in the U.S. that selected its technology for deployment
2007 through 2016	Florida Power & Light	Strategic Advisory	Assisted the company with its efforts to develop an option to construct and operate two new reactors at the company's Turkey Point facility. Since 2008, we have also assessed the project controls and project management practices used to plan and implement four extended power uprate projects.
2008	Ontario Power Generation	Strategic Advisory	Evaluated the possible risk premium associated with developing, constructing and owning a new nuclear power plant that was under consideration by OPG on a standalone basis.
2010	Confidential Nuclear Power Plant Owner	Strategic Advisory	Provided strategic advice related to a potential sale of a nuclear facility.
2010, 2012	Exelon	Appraisal	Provided appraisals of certain nuclear generating facilities and also provided a full range of services to support Exelon's external appraiser.
2011	Confidential Nuclear Power Plant Owner	Strategic Advisory	Provided an analysis of strategic alternatives for a U.S. company with a single nuclear unit.
2013, 2014	PNM Resources	Nuclear Valuation	Conducted a financial valuation of a 10.2% interest in Palo Verde Unit #3 (134 MW) which was used in a state regulatory proceeding.
2015	Confidential Client	Appraisal	Acted as the third-party independent appraiser of the client's nuclear generating facility.
2015	NYSEG	Nuclear PPA	Provided services to NYSEG related to a potential PPA for its Ginna nuclear facility, including: evaluate an estimate for five years (2014-2019) of going forward costs; review NRC requirements for nuclear plant shutdown; analyze a decommissioning cost estimate vs

Year	Primary Client	Engagement Type	Project Description
			current decommissioning fund levels; research notice provisions; research NRC requirements for a nuclear plant mothball; assess going forward market viability; review filed a cost of service study; and develop a strategy for negotiations.
2016	Confidential Client	Appraisal	Provided an independent appraisal of the confidential client's generating station and end of lease valuation.
2016	Mitsubishi Heavy Industries, Ltd., and Mitsubishi Nuclear Energy Systems, Inc.	Litigation Support	Concentric provided expert testimony related to damages claimed, including lost economic value, under a nuclear power equipment contract.

CCC Interrogatory #15

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference: H1/T1/S1

Please set out how much of OPG's revenue requirement for both the hydroelectric business and nuclear business are subject to deferral account treatment

Response

Assuming that the existing deferral and variance accounts are authorized to continue, OPG estimates that in the order of 20%-30% of the 2017-2021 revenue requirement would be at least partially subject to deferral and variance account treatment. In making this estimate, OPG used the 2017-2021 nuclear revenue requirement proposed in this application and the average of 2014/2015 hydroelectric revenue requirements approved in EB-2013-0321, adjusted to remove the one-time allocation of nuclear tax losses to the hydroelectric business consistent with OPG's "going in" rates under its IRM proposal (Ex. A1-3-2, section 2.3.2).

In order to arrive at the 20%-30% estimate, OPG has taken the sum of all elements of the revenue requirement that are subject to deferral and variance account treatment and divided those amounts by the total revenue requirement. This indicates how much of the revenue requirement is subject to deferral and variance accounts, but does not provide an estimate of the amounts that will be recorded as entries into these accounts. For example, the calculation of the 20-30% range includes the full forecast cash pension and OPEB cash amounts embedded in the revenue requirement; however, only variances from these amounts would be recorded into the associated Pension & OPEB Cash Payment Variance Account. In addition, the disposition of balances [not all balances are subject to prudence, such as NLDA] in the deferral and variance accounts is subject to a prudence review.

As discussed in Undertaking J3.9 in EB-2013-0321, some elements of the revenue requirement are subject to accounts that do not cover all sources of variance from forecast amounts. For example, the Income and Other Taxes Variance Account captures only certain variances, such those related to changes in tax rates or rules and income tax audits, but not other sources of variance. Nevertheless, these elements of the revenue requirement are included in the 20%-30% figure above even though they are only subject to deferral or variance account treatment in certain circumstances.

As noted in EB-2007-0905, one of OPG's deferral and variance accounts is unrelated to the prescribed facilities, the Bruce Lease Net Revenues Variance Account, but it is included in

1 the estimate provided above (EB-2007-0905, Decision with Reasons, November 3, 2008,
2 page 147).

3
4 Based on its nuclear rate smoothing proposal, OPG also is proposing to defer the collection
5 of an average of 10% of the annual nuclear revenue requirement, but this amount is not
6 considered in the estimate provided above. For clarity, amounts to be recorded in the
7 associated Rate Smoothing Deferral Account would be fixed in this proceeding based on the
8 approved revenue requirement (see Ex. H1-1-1 section 6.1). Variances from the approved
9 revenue requirement subject to deferral and variance account treatment (i.e., those in the 20-
10 30% range) would be recorded in the applicable deferral and variance accounts in the same
11 manner as previously, notwithstanding the amount deferred under rate smoothing.

GEC Interrogatory #1

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

C1-1-1 att.1 Concentric Report

Concentric notes that the DRP and Pickering life extension as well as the growth in nuclear versus hydraulic assets increases OPG's risk profile which leads to a recommended increase in the equity ratio from 45 to 49%

- a) Please confirm that any increase in capital costs due to the size and risk of the DRP will apply to the entire rate base, not just the DRP and Pickering portion.
- b) Please estimate how much of the suggested shift in equity ratio is attributable to the DRP and how much is attributable to the Pickering life extension.
- c) Please quantify the net present value in total over the life of the Darlington facilities for the increase in the cost of capital for the non-DRP portion of the rate base due to the portion of this shift in risk attributable to the DRP.
- d) Please indicate whether the value provided in answer to part c, above, has been included in the \$12.8B DRP cost estimate and if so, provide that analysis.
- e) Please quantify the net present value in total over the life of the Pickering facilities for the increase in the cost of capital for the non-Pickering portion of the rate base due to the portion of this shift in structure attributable to the Pickering life extension.
- f) Please indicate whether the value provided in answer to part e, above, has been included in the cost estimate and in the cost effectiveness studies of the Pickering life extension and provide that analysis.

Response

Parts a and b of this response were prepared by Concentric Energy Advisors

- a) Confirmed. The proposed change in capital structure will apply to the entire rate base, which includes capital costs of assets in service. It is a standard ratemaking practice to apply one weighted average cost of capital to the utility's rate base that reflects the rate of return (inclusive of capital structure) that would be required for investment in companies of comparable risk. As such, the weighted average cost of capital reflects the entirety of the risk profile of the enterprise. Consistent with that practice, and as

1 described in Concentric's report, Concentric performed a risk analysis of the entirety of
2 OPG's regulated operations, and based the recommendations on that analysis, in
3 conjunction with a comparative analysis of proxy companies to provide context for where,
4 within a reasonable range, OPG's equity ratio should be set by the OEB.
5
6

- 7 b) As summarized in Concentric's report, the recommended capital structure and associated
8 increase in the equity ratio are based on a number of factors:
9 • The change in the nuclear to hydroelectric asset mix;
10 • The increase in OPG's business risk driven by the DRP;
11 • Plans to pursue extended Pickering operations beyond 2020 and the aging of the
12 Pickering plant;
13 • The move to IR for hydroelectric rate-setting and to long-term rate-setting periods
14 for nuclear operations;
15 • The recovery risks associated with pension and OPEB costs and revenue deferred
16 under rate smoothing; and
17 • OPG's higher risk relative to comparable firms that have a median equity ratio of
18 almost 50% (Ex. C1-1-1, Att. 1, p 5.).

19 The DRP and Pickering life extension projects are key elements of Concentric's risk
20 assessment, but it is not possible to isolate the effects of these projects, together or
21 individually, from the overall risk assessment of OPG. While one could calculate the
22 increase in capital expenditures for the projects, the capital mix is just one aspect of
23 Concentric's overall risk assessment.

24 The question is effectively asking for a cost of capital for the DRP, the Pickering Life
25 Extension project and, by default everything else (remaining nuclear operations plus
26 hydro). This would represent an even finer breakdown than a nuclear and hydroelectric
27 specific capital structure, an issue examined by the OEB in EB-2010-0008. In rejecting
28 prior proposals for a technology-specific capital structure in EB-2010-0008, the Board
29 found that: (1) there was a "paucity of comparator firms;" (2) use of technology-specific
30 capital structures would introduce a "level of variability and complexity [that] would not
31 be appropriate"; and (3) such an approach "may not lead to any significant ratepayer
32 benefits in the long term."
33

- 34 c) to f) As discussed in response to part b) it is not possible to isolate the effects of these
35 projects from the overall risk assessment of OPG.

SEC Interrogatory #9

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Please provide a list of periodic reports that are made to Executive Management of the OPG, its Board of Directors or committees, or any part of the government of Ontario, dealing with planned or achieved ROE. For each category of such reports (e.g. Board of Directors), please provide all such reports delivered in the most recent two years.

Response

OPG does not produce reports for the Province or any part of the government of Ontario, the company's Board of Directors or committees thereof, or Executive Management on its regulated ROE.

OPG provides disclosure of its achieved corporate-wide ROE in its annual and quarterly Management Discussion & Analysis documents filed with the Ontario Securities Commission (e.g., Ex. A2-1-1, Attachment 3, pp. 15-16 for the 2015 year-end).

VECC Interrogatory #5

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Reference: C1/T1/S1

In terms of OPG's requested capital structure at EB2016-0152 please provide the following:

- a) The actual approved capital structure of OPG for each year since 2005.
- b) The applied capital structure for each year in EB2007-0905 and subsequent applications.
- c) The percentage rate base assets in nuclear and hydro for each year since 2005.
- d) The forecast rate base percentage assets for each year in nuclear and hydro in EB-2007-0905 and subsequent applications.
- e) Please restate the Chart 1 data on page 1 to include the periods between 2005 and 2016.

Response

- a) See Attachment 1, Table 1
- b) See Attachment 1, Table 2
- c) See Attachment 1, Table 3
- d) See Attachment 1, Table 4
- e) See Attachment 1, Table 5

Numbers may not add due to rounding.

Filed: 2016-10-26
EB-2016-0152
Exhibit L
Tab 3.1
Schedule 20 VECC-005
Attachment 1
Table 1

Table 1
Approved Capital Structure¹

Line No.		2008	2009	2011	2012	2014	2015
		(a)	(b)	(c)	(d)	(e)	(f)
1	Rate Application	EB-2007-0905 ²	EB-2007-0905 ²	EB-2010-0008 ³	EB-2010-0008 ³	EB-2013-0321 ⁴	EB-2013-0321 ⁴
	Approved Capital Structure						
2	Equity	47.0%	47.0%	47.0%	47.0%	45.0%	45.0%
3	Debt	53.0%	53.0%	53.0%	53.0%	55.0%	55.0%

Notes:

- 1 The first approved capital structure from the OEB was issued in EB-2007-0905 for 2008
- 2 2008-2009 from EB-2007-0905 Payment Amounts Order Appendix A, Table 4b, 5b respectively
- 3 2011-2012 from EB-2010-0008 Payment Amounts Order Appendix A, Table 4b, 5b respectively
- 4 2014-2015 from EB-2013-0321 Payment Amounts Order Appendix A, Table 5b, 6b respectively

Numbers may not add due to rounding.

Filed: 2016-10-26
 EB-2016-0152
 Exhibit L
 Tab 3.1
 Schedule 20 VECC-005
 Attachment 1
 Table 2

Table 2
Proposed Capital Structure¹

Line No.		2008	2009	2011	2012	2014	2015
		(a)	(b)	(c)	(d)	(e)	(f)
1	Rate Application	EB-2007-0905 ²	EB-2007-0905 ²	EB-2010-0008 ³	EB-2010-0008 ³	EB-2013-0321 ⁴	EB-2013-0321 ⁴
	Proposed Capital Structure						
2	Equity	57.5%	57.5%	47.0%	47.0%	47.0%	47.0%
3	Debt	42.5%	42.5%	53.0%	53.0%	53.0%	53.0%

Notes:

- 1 OPGs first rate application to the OEB was EB-2007-0905 for 2008 and 2009 rates
- 2 2008-2009 from EB-2007-0905 Ex. C1-2-1 Table 3,2 respectively
- 3 2011-2012 from EB-2010-0008 Ex. C1-1-1 Table 3,2,1 respectively
- 4 2014-2015 from EB-2013-0321 Ex. C1-1-1 Table 3,2,1 respectively

Numbers may not add due to rounding.

Filed: 2016-10-26
EB-2016-0152
Exhibit L
Tab 3.1
Schedule 20 VECC-005
Attachment 1
Table 3

Table 3
Actual Rate Base

Line No.		2005	2006	2007	2008 ³	2009 ³	2010 ³	2011 ³	2012 ³	2013 ³	2014 ^{3,4}	2015 ^{3,4}
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Actual Rate Base											
1	Hydro¹	4,001.3	3,957.3	3,911.1	3,871.5	3,834.0	3,798.0	3,771.8	3,744.0	4,828.5	7,547.5	7,473.2
2	Nuclear²	2,865.5	3,005.7	3,500.1	2,501.4	2,261.5	2,377.7	2,368.6	2,281.9	2,309.7	2,325.0	2,346.5
3	Total Rate Base	6,866.8	6,963.0	7,411.2	6,372.9	6,095.5	6,175.6	6,140.4	6,025.9	7,138.2	9,872.4	9,819.7
4	% Hydro	58.3%	56.8%	52.8%	60.7%	62.9%	61.5%	61.4%	62.1%	67.6%	76.4%	76.1%
5	% Nuclear	41.7%	43.2%	47.2%	39.3%	37.1%	38.5%	38.6%	37.9%	32.4%	23.6%	23.9%

Notes:

- Actual Rate Base: 2005-2007 from EB-2007-0905 Ex. B1-1-1 Table 1
2008-2009 from EB-2010-0008 Ex. B1-1-1 Table 1
2010-2012 from EB-2013-0321 Ex. B1-1-1 Table 1
- Actual Rate Base: 2005-2007 from EB-2007-0905 Ex. B1-1-1 Table 2
2008-2009 from EB-2010-0008 Ex. B1-1-1 Table 2, less UNL/ARC from Ex. C1-1-1 Tables 5,4 respectively
2010-2012 from EB-2013-0321 Ex. B3-2-1 Table 1 line 1
2013-2015 from EB-2016-0152 Ex. B3-2-1 Table 1 line 1
- Nuclear amounts do not include the lesser of unamortized asset retirement costs ("ARC") or unfunded nuclear liabilities ("UNL"). This is consistent with the OEB-approved methodology for determining rate base financed by capital structure, wherein the weighted average cost of capital is applied to OPG's rate base that does not include the lesser of ARC or UNL.
- Newly regulated hydroelectric facilities are included for the full year beginning on January 1, 2014, as presented in the EB-2013-0321 Payment Amounts Order.

Numbers may not add due to rounding.

Filed: 2016-10-26
EB-2016-0152
Exhibit L
Tab 3.1
Schedule 20 VECC-005
Attachment 1
Table 4

Table 4
OEB Approved Rate Base

Line No.		2008	2009	2011	2012	2014	2015
		(a)	(b)	(c)	(d)	(e)	(f)
1	Rate Application	EB-2007-0905	EB-2007-0905	EB-2010-0008	EB-2010-0008	EB-2013-0321	EB-2013-0321
	Approved Rate Base¹						
2	Hydro	3,880.2	3,869.9	3,803.4	3,787.4	7,525.7	7,489.6
3	Nuclear²	2,448.8	2,470.9	2,392.5	2,354.7	2,317.2	2,350.2
4	Total Rate Base	6,329.0	6,340.8	6,195.9	6,142.1	9,843.0	9,839.8
5	% Hydro	61.3%	61.0%	61.4%	61.7%	76.5%	76.1%
6	% Nuclear	38.7%	39.0%	38.6%	38.3%	23.5%	23.9%

Notes:

- 1 Approved Rate Base: 2008-2009 from PAO Appendix A, Tables 1-2
2011-2012 from EB-2010-0008 PAO Appendix A, Tables 1-2
2014-2015 from EB-2013-0321 PAO Appendix A, Tables 1-3
- 2 Nuclear amounts do not include the lesser of unamortized asset retirement costs ("ARC") or unfunded nuclear liabilities ("UNL"). This is consistent with the OEB-approved methodology for determining rate base financed by capital structure, wherein the weighted average cost of capital is applied to OPG's rate base that does not include the lesser of ARC or UNL.

Numbers may not add due to rounding.

Updated: 2016-11-10
EB-2016-0152
Exhibit L
Tab 3.1
Schedule 20 VECC-005
Attachment 1
Table 5

Table 5
Nuclear Portion of Total Rate Base

Line No.		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Hydro (\$B) ¹	4.0	4.0	3.9	3.9	3.8	3.8	3.8	3.7	4.8	7.5	7.5	7.4	7.5	7.5	7.5	7.6	7.7
2	Nuclear (\$B) ^{2,3}	2.9	3.0	3.5	2.5	2.3	2.4	2.4	2.3	2.3	2.3	2.3	2.7	3.3	3.5	3.5	7.5	8.0
3	Total (\$B)	6.9	7.0	7.4	6.4	6.1	6.2	6.1	6.0	7.1	9.9	9.8	10.2	10.8	11.0	10.9	15.1	15.6
4	Nuclear Proportion of Total Rate Base (%)	42%	43%	47%	39%	37%	39%	39%	38%	32%	24%	24%	27%	31%	32%	32%	50%	51%

Notes

- 1 2005-2007 from EB-2007-0905 Ex. B1-1-1 Table 1
2008-2009 from EB-2010-0008 Ex. B1-1-1 Table 1
2010-2012 from EB-2013-0321 Ex. B1-1-1 Table 1
- 2 2005-2007 from EB-2007-0905 Ex. B1-1-1 Table 2
2008-2009 from EB-2010-0008 Ex. B1-1-1 Table 2, less UNL/ARC from Ex. C1-1-1 Tables 5 and 4 respectively
2010-2012 from EB-2013-0321 Ex. B3-2-1 Table 1 line 1
2013-2021 from EB-2016-0152 Ex. B3-2-1 Table 1 line 1, 4, and 7
- 3 For 2008 - 2021 Nuclear amounts do not include the lesser of unamortized asset retirement costs ("ARC") or unfunded nuclear liabilities ("UNL"). This is consistent with the OEB-approved methodology for determining rate base financed by capital structure, wherein the weighted average cost of capital is applied to OPG's rate base that does not include the lesser of ARC or UNL.

VECC Interrogatory #6

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Reference: C1/T1/S1

In terms of the return on equity (ROE):

- a) Please provide the actual return on equity for each year since and including 2005.
- b) Please provide the approved ROE for each year since 2005.
- c) Please indicate how the approved ROE was set for each year.
- d) Please explain the factors that generated any differences between the actual and approved ROE.
- e) Please indicate which periods OPG was regulated under any measures that could be defined as performance based incentive regulation.
- f) With reference to the request deferral account on page 2, please provide a list of all the variance accounts available to OPG's regulated operations and the year end 2016 balances in each.

Response

- a) OPG's actual return on equity for 2005-2015 is provided in Chart 1 below

Chart 1

2005	2006	2007	2008	2009	2010
2.43%	5.70%	(6.70)%	(3.11)%	1.10%	4.71%
2011	2012	2013	2014	2015	
4.80%	4.73%	0.46%	6.32%	3.63%	

- b) OPG's OEB approved ROE is provided in Chart 2 below. OPG's first rates application to the OEB was EB-2007-0905 where the OEB approved an ROE for 2008 and 2009. As such OPG does not have an OEB approved ROE prior to 2008.

Chart 2

2008	2009	2011	2012	2014	2015
EB-2007-0905	EB-2007-0905	EB-2010-0008	EB-2010-0008	EB-2013-0321	EB-2013-0321
8.65%	8.65%	9.43%	9.55%	9.36%	9.30%

- c) OPG's OEB approved ROE have been set as follows:
- EB-2007-0905:** Set at 8.65% consisting of a forecast long-term risk free rate of 4.75%, a risk premium of 3.4%, and a 0.5% adjustment for financing flexibility¹.
- EB-2010-0008:** Set at 9.43% for 2011 based on Bloomberg LLP, Consensus Forecasts, and Bank of Canada data for November 2010, which is three months in advance of March 1, 2011, and using the ROE methodology in Appendix B of the Cost of Capital Report². Set at 9.55% for 2012 based on the Global Insight forecast and the OEB's methodology³.
- EB-2013-0321:** Set at the OEB's Return on Equity for 2014 at 9.36%. Set at 9.3% for 2015 using the OEB's 2015 cost of capital parameters⁴.
- d) OPG's actual ROE has varied from OEB approved values predominantly as a result of variances in actual expenditures and nuclear production from OEB approved forecasts.
- e) OPG has not previously been regulated under measures defined as performance based incentive regulation.
- f) Attachment 1 provides the list of all variance and deferral accounts currently authorized for OPG's regulated operations and the projected year-end 2016 balances and activity therein, in the form of Ex. H1-1-1 Table 1a. The projected balances are based on 2016 forecasts in the pre-filed evidence, as updated for the impact on the pension contributions of the January 1, 2016 actuarial valuation of the OPG pension plan (see Ex. L-6.6-1 Staff-156).

¹ See EB-2007-0905 Decision with Reasons, Pages 157-158

² See EB-2010-0008 Decision and Order, Page 122

³ See EB-2010-0008 Decision and Order, Page 123

⁴ See EB-2013-0321 Decision and Order, page 117

Numbers may not add due to rounding.

Filed: 2016-10-26
EB-2016-0152
Exhibit L
Tab 3.1
Schedule 20 VECC-006
Attachment 1
Table 1

Table 1
Deferral and Variance Accounts
Continuity of Account Balances - Projected 2016 (\$M)¹

Line No.	Account	Audited Year End Balance 2015 ²	Projected 2016				(a)+(b)+(c)+(d)+(e) Projected Year End Balance 2016
			Transactions	Amortization ³	Interest ⁴	Transfers	
		(a)	(b)	(c)	(d)	(e)	(f)
	Hydroelectric:						
1	Hydroelectric Water Conditions Variance	(23.0)	(38.2)	5.6	(0.4)	0.0	(55.9)
2	Ancillary Services Net Revenue Variance - Hydroelectric	(24.2)	(22.4)	11.0	(0.3)	0.0	(36.0)
3	Hydroelectric Incentive Mechanism Variance	(1.7)	0.0	1.7	(0.0)	0.0	(0.1)
4	Hydroelectric Surplus Baseload Generation Variance	114.4	43.9	(31.9)	1.3	0.0	127.7
5	Income and Other Taxes Variance - Hydroelectric	(0.1)	0.0	0.1	(0.0)	0.0	(0.0)
6	Capacity Refurbishment Variance - Hydroelectric	83.2	2.1	(79.9)	0.5	0.0	5.9
7	Pension and OPEB Cost Variance - Hydroelectric - Future	9.5	0.0	(1.1)	0.0	0.0	8.4
8	Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions	32.5	0.0	(5.9)	0.0	0.0	26.6
9	Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric	44.2	28.6	0.0	0.0	0.0	72.7
10	Pension & OPEB Cash Payment Variance - Hydroelectric	4.3	(12.2)	0.0	0.0	0.0	(8.0)
11	Niagara Tunnel Project Pre-December 2008 Disallowance Variance	0.0	3.9	0.0	0.0	0.0	3.9
12	Hydroelectric Deferral and Variance Over/Under Recovery Variance	16.5	(5.1)	(3.0)	0.1	0.0	8.5
13	Total	255.5	0.6	(103.4)	1.2	0.0	153.8
	Nuclear:						
14	Nuclear Liability Deferral	190.5	0.0	(190.5)	0.0	0.0	0.0
15	Nuclear Development Variance	3.3	2.0	(1.6)	0.0	0.0	3.7
16	Ancillary Services Net Revenue Variance - Nuclear	2.1	0.7	(1.2)	0.0	0.0	1.7
17	Capacity Refurbishment Variance - Nuclear - Capital Portion	(32.5)	10.2	(5.0)	(0.3)	0.0	(27.7)
18	Capacity Refurbishment Variance - Nuclear - Non-Capital Portion	(30.8)	(9.4)	(0.8)	(0.4)	0.0	(41.4)
19	Bruce Lease Net Revenues Variance - Derivative Sub-Account	(4.5)	0.0	(64.1)	0.0	0.0	(68.6)
20	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002	18.7	0.0	(18.7)	0.0	0.0	0.0
21	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions	103.1	95.4	(82.5)	0.0	0.0	116.0
22	Income and Other Taxes Variance - Nuclear	(13.1)	0.0	8.8	(0.1)	0.0	(4.4)
23	Pension and OPEB Cost Variance - Nuclear - Future	193.2	0.0	(21.5)	0.0	0.0	171.7
24	Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions	622.0	0.0	(113.1)	0.0	0.0	508.9
25	Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear	271.1	187.5	0.0	0.0	0.0	458.6
26	Pension & OPEB Cash Payment Variance - Nuclear	23.4	(60.9)	0.0	0.4	0.0	(37.1)
27	Pickering Life Extension Depreciation Variance	5.2	0.0	(5.2)	0.0	0.0	0.0
28	Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral	0.0	(70.5)	0.0	0.0	0.0	(70.5)
29	Nuclear Deferral and Variance Over/Under Recovery Variance	81.7	12.9	(37.6)	0.8	0.0	57.8
30	Total	1,433.4	167.8	(533.0)	0.4	0.0	1,068.7
31	Grand Total (line 13 + line 30)	1,688.9	168.4	(636.4)	1.6	0.0	1,222.5

Notes:

- Based on 2016 forecasts reflected in EB-2016-0152 pre-filed evidence, updated for impact of January 1, 2016 actuarial valuation for funding purposes on projected pension contributions (Ex. L-6.6-1 Staff-156).
- From Ex. H1-1-1 Table 1, col. (b).
- From EB-2014-0370 Payment Amounts Order, App. B, Table B-1, col. (d).
- Per the EB-2014-0370 Payment Amounts Order, no interest is recorded on the Pension & OPEB Cash Versus Accrual Differential Deferral Account, Pension and OPEB Cost Variance Account, Bruce Lease Net Revenues Variance (from January 1, 2015 to December 31, 2016), Nuclear Liability Deferral Account, and Pickering Life Extension Depreciation Variance Account.
Per the EB-2015-0374 Decision and Order, no interest is recorded on the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account.

VECC Interrogatory #7

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Reference: C1/T1/S1

Pre-ambule: In terms of the overall Cost of capital, EB2016-0152, OPG was part of Ontario Hydro and as a Crown corporation required to provide electricity at cost. Subsequently, it was converted to a separate OBCA company, required to make payments in lieu of income taxes, finance with a higher percentage of "equity" and charge HST on its revenues. In each case, additional money flowed to the Province of Ontario either as HST, equity income or PILs. As a Crown, OPG was generally required to earn 115% of its interest payments, similar to other Canadian Crown owned electricity companies.

- a) Starting with OPG's 2017 requested operating income after interest, please identify the additional monies earned by the Province of Ontario above what it would have earned if OPG was still regulated as a Crown corporation, namely the result of changes to:
 - i. OPG's requested capital structure versus the 115% interest coverage target;
 - ii. The imposition of PILs; and,
 - iii. The provincial HST charge.
- b) Please show all calculations and the increase in the total charge for electricity resulting from the increased payments to its owner, the Province of Ontario, due to these policy changes.
- c) In OPG's judgement is it riskier being regulated as a Crown with lower electricity charges or as an OBCA company 100% owned by the Province of Ontario?

Response

OPG declines to produce the requested information on the basis of relevance. The questions ask OPG to speculate on the outcomes of a scenario in which the Province had not passed the *Energy Competition Act*, 1998. It is not relevant to any issue before the OEB in this proceeding and is of no probative value in determining OPG's cost of capital.

VECC Interrogatory #8

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Reference: C1/T1/S1/Attachment 1 - Concentric Energy Report

- a) Please confirm that in April 19, 2013 Concentric Energy provided a report to the Regie authored by Mr. Coyne and Mr. Trogonoski with a recommended fair ROE and common equity ratio for Hydro Quebec Transmission (HQT) and Hydro Quebec Distribution (HQD).
- b) Please provide a copy of that testimony and confirm that:
- i. the recommended and allowed common equity ratio was 30% for HQT and 35% for HQD;
 - ii. the recommendations were based on the stand-alone principle; and,
 - iii. that on page 9 of the summary Concentric stated:

"the only important difference is that a percentage of electric companies in the US Proxy group (and in Canada) own some regulated generation, which suggests that these companies have somewhat more business risk than HQD and HQT."
 - iv. that on page 53 of that report Concentric stated:

"as discussed in the following section of this testimony the incremental ROE required to offset the increased operating risk of regulated generation is approximately 41 basis points."

In the context of an incremental ROE of 0.41% please indicate how much this would translate to in terms of common equity ratio if the ROE were not adjusted for the differential generating risk.
 - v. that the Regie allowed HQT and HQD an ROE of 8.2% while at the same time the Ontario formula ROE allowed Ontario's electric distributors an ROE of 9.30% and Concentric recommended the same 9.22% ROE for HQT and HQD.
- c) Please confirm that S&P has a policy of not rating debt issued by subsidiaries higher than that of its parent unless it is "ring fenced" and that OPG was downgraded to BBB+ because S&P downgraded its parent, the Province of Ontario. In addition:
- i. Please indicate whether the actions of S&P in its rating policy is consistent with the stand alone principle of regulation
 - ii. Please provide copies of both the S&P OPG rating and the current DBRS rating and report.

- 1 iii. Please explain in detail why the selection criteria used to form proxy samples for
2 OPG are different from those used for HQT and HQD.
3 iv. Please confirm that none of the utilities in the proxy group on Page 34 are 100%
4 provincially or state owned and that Concentric's recommendation would not
5 change if OPG were still a Crown corporation, rather than an OBCA company.
6 v. Please confirm that OPG is included in the Provincial budget as income from
7 government business enterprises.
8
9

10 Response
11

12 The following response was prepared by Concentric Energy Advisors:
13

- 14 a) Concentric did provide a report to the Regie de L'Energie on April 19, 2013, in which
15 Concentric recommended a fair return on equity for Hydro Quebec TransEnergie ("HQT")
16 and Hydro Quebec Distribution ("HQD").
17
18 b) Please see 3.1 VECC-8, Attachment 1 for a copy of the report.
19 i. Concentric's report for HQT and HQD focused on the authorized ROE. Concentric
20 did not recommend any change to the deemed equity ratio for either HQT or HQD.
21 However, page 52 of Concentric's report for HQT and HQD states:

22 *HQD and HQT are proposing to maintain their current deemed*
23 *equity ratios of 35.0 percent and 30.0 percent, respectively. As*
24 *discussed in Appendix B, the equity ratios for HQD and HQT are*
25 *somewhat lower than the deemed equity ratios for the operating*
26 *divisions of the Canadian proxy group, and are substantially*
27 *lower than the authorized equity ratios of the U.S. electric utility*
28 *proxy group. In order for HQD and HQT to have the opportunity*
29 *to earn weighted compensatory equity return at their respective*
30 *equity ratios as the U.S. electric utility proxy group at an average*
31 *equity ratio of 50.2 percent, significant increases in the*
32 *authorized ROE would be required to compensate for the*
33 *difference in authorized capital structure. Using commonly-*
34 *accepted methodologies, Concentric estimates that an*
35 *adjustment to ROE of between approximately 1.50 percent and*
36 *3.00 percent would be warranted to compensate for a 15 to 20*
37 *percent decline in the common equity ratio from the U.S. proxy*
38 *group average.*
39

40 The Regie's Order did not modify the 30% deemed equity ratio for HQT or the 35%
41 deemed equity ratio for HQD.
42

- 43 ii. The ROE recommendations were made based on the stand-alone principle.

- 1
2 iii. Confirmed. In addition, the following bullet point on page 9 of Concentric's report
3 for HQT and HQD states:
4

5 *Financial Risk – HQD and HQT have somewhat more financial leverage in*
6 *their capital structures than the Canadian utilities and substantially more*
7 *financial leverage and weaker credit metrics than the U.S. electric utility*
8 *proxy group companies. Credit rating agencies may be satisfied with the*
9 *degree of regulatory protection and cash flow protection for debt investors,*
10 *but these metrics expose equity investors to greater risk than their U.S.*
11 *counterparts. As such, HQD and HQT have greater financial risk than the*
12 *U.S. electric utility proxy group, which more than offsets the ownership of*
13 *regulated generation described above.*
14

- 15 iv. Confirmed. The complete response on page 53 of Concentric's report for HQT and
16 HQD states:

17 *As discussed in the following section of this testimony, the*
18 *incremental ROE required to offset the increased operating risk of*
19 *regulated generation is approximately 41 basis points. Although*
20 *Concentric does not propose an adjustment in this proceeding for the*
21 *difference in capital structure between HQD and HQT and the U.S.*
22 *electric utility proxy group, Concentric views the financial risk of a*
23 *more highly-leveraged capital structure as more than offsetting any*
24 *potential difference in the required ROE of the U.S. electric utility*
25 *proxy group companies that own regulated generation.*
26

27 The cited passage from the HQT and HQD evidence states that there has
28 been a 41 basis point ROE differential between vertically-integrated electric
29 utilities and transmission and distribution only utilities. However, OPG is a
30 generation only utility. Concentric does not believe it is appropriate (or even
31 possible) to try to translate the 41 basis point ROE differential for integrated
32 electric utilities and T&D utilities to an equity ratio differential for a
33 generation-only utility like OPG.
34

- 35 v. Concentric confirms that the Regie allowed HQT and HQD to increase their
36 authorized ROE to 8.20% from the previous level of 6.41% for HQT and 6.19% for
37 HQD, which had been set under the Regie's automatic adjustment formula.
38 Concentric's understanding is that the formula ROE in Ontario was 9.36% in 2014,
39 which is when the 8.20% ROE became effective for HQT and HQD. Concentric
40 confirms that our recommendation for HQT and HQD in the 2013 report was 9.22%.
41

- 1 c) Concentric confirms that S&P's ratings methodology for electric and gas utilities is based
2 on a consolidated profile, and that subsidiaries are not rated higher than the parent
3 unless there is ring-fencing in place. Concentric also confirms that OPG was
4 downgraded by S&P in July 2015 because S&P downgraded the Province of Ontario.
5
- 6 i. As stated in response to VECC-009, part a), the stand-alone principle is a "long-
7 established regulatory principle." In performing its credit rating analysis, Standard
8 and Poor's is not applying a regulatory principle, but rather is assessing the
9 creditworthiness and likelihood of default for an issuer based on S&P's stated
10 ratings methodology. Concentric notes that while S&P links the rating of OPG to
11 the Province of Ontario, it rates the Company three notches below the Province
12 (i.e., BBB+ for OPG as compared to A+ for the Province of Ontario). S&P has
13 further indicated that on a stand-alone basis (i.e., without provincial support) OPG
14 would have a BBB- rating, or two notches lower. By comparison, as indicated in
15 Footnote 29 to the Concentric report for HQT and HQD that was provided in
16 response to 3-1-VECC-8(a), Moody's Investors Service indicated in an August 2012
17 report that its Baseline Credit Assessment for Hydro-Quebec would be Baa1 (S&P
18 equivalent BBB+) absent the government debt guarantee of the Province of
19 Quebec. This rating for Hydro-Quebec is two notches higher than OPG's stand-
20 alone credit profile, suggesting that OPG is viewed as riskier from a credit
21 perspective than Hydro-Quebec.
22
- 23 ii. Please see 3.1-VECC-8, Attachments 2 and 3 for S&P reports and Attachment 4 for
24 the DBRS report.
25
- 26 iii. Concentric agrees that the screening criteria used to select the comparator group
27 for OPG are different than the screening criteria used to estimate the cost of equity
28 for HDT and HQD. These differences are primarily driven by two factors: 1) the
29 specific utilities involved; and 2) the purpose of the analysis. As discussed on page
30 29 of Concentric's report, OPG is unique in that its regulated operations consist of
31 100% generating assets; therefore, it is not possible to find proxy companies that
32 are perfectly comparable from a risk perspective. With regard to the specific utilities
33 involved, OPG is a generation utility that owns significant regulated nuclear and
34 hydroelectric assets, whereas HDT and HQD are regulated transmission and
35 distribution utilities. The Board has found that OPG is of higher risk transmission
36 and distribution utilities, stating, in EB-2007-0905, page 149: "[t]he Board has
37 concluded that OPG is of higher risk than electricity LDCs, gas utilities and
38 electricity transmission utilities and of lower risk than merchant generation." In
39 developing the comparator group for OPG, Concentric determined it was
40 appropriate to screen for companies that own regulated generation assets that are
41 included in rate base, and companies that own regulated nuclear and/or
42 hydroelectric generation. These screens were not used for selecting companies

1 comparable to HQT and HQD because HQT and HQD do not own regulated
2 generation.

3
4 In terms of the purpose of the analysis, Concentric's report for OPG is
5 recommending a deemed equity ratio, while for HQT and HQD Concentric was
6 recommending the authorized return on equity. Certain screens that are typically
7 used to develop a proxy group for purposes of estimating the cost of equity were
8 not applied to develop a proxy group for the purpose of establishing a capital
9 structure. For example, in the report for HQT and HQD, Concentric excluded
10 companies that 1) did not pay dividends, 2) did not have earnings growth rates from
11 at least two utility industry analysts, 3) were considered a small capitalization
12 company, and 4) were involved in a merger or other transformative transaction.
13 Those criteria were not used for purposes of developing a comparator group in
14 order to determine an appropriate equity ratio for OPG. Rather, these screens are
15 relevant for purposes of ensuring that sufficient data are available in order to
16 estimate the cost of equity using the DCF and CAPM methods, which were not
17 applied in this case.

18
19 iv. Concentric confirms that none of the utilities in the proxy group are provincially or
20 state owned. Further, Concentric confirms that our recommendation would not
21 change if OPG were still a crown corporation.

22
23 v. Concentric's assessment of OPG's risk profile was performed on a stand-alone
24 basis, consistent with the Board's application of the stand-alone principle in prior
25 OPG payment amount application proceedings. Specifically, the Board has
26 previously found (EB-2007-0905, page 142):

27
28 *The Board concludes that if OPG is operated at arm's length, then it should be*
29 *examined in the same way as Hydro One, another energy utility owned by the*
30 *Province. In other words, Provincial ownership will not be a factor to be considered*
31 *by the Board in establishing capital structure.*

32
33 As such, Concentric did not evaluate whether OPG is included in the Provincial
34 budget as income from government business enterprises.

**Témoignage de
MM. James M. Coyne et John P. Trogonoski
de Concentric Energy Advisors
sur le taux de rendement et l'analyse de risque**



ROE and Risk Analysis

Prepared Direct Testimony of

James M. Coyne and

John P. Trogonoski

On behalf of Hydro-Québec Distribution

and Hydro-Québec TransÉnergie

Presented to the

Régie de l'énergie

April 19, 2013

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1 **I. INTRODUCTION**

2 Concentric Energy Advisors, Inc. (“Concentric”) provides this testimony on behalf
3 of Hydro-Québec Distribution (“HQD”) and Hydro-Québec TransÉnergie
4 (“HQT”) under two witnesses who have collaborated in its preparation. Mr. Coyne’s
5 testimony primarily relates to the determination of the appropriate ROE; Mr.
6 Trogonoski’s testimony primarily relates to the associated risk analysis. The words
7 “Concentric”, “we”, and “our” are used interchangeably in the text.

8 **A. QUALIFICATIONS**

9 **Q. Please state your name, affiliation, and business address.**

10 A. My name is James M. Coyne, and I am employed by Concentric as a Senior Vice
11 President. My business address is 293 Boston Post Road West, Suite 500,
12 Marlborough, MA 01752.

13 **Q. Please describe your experience and qualifications.**

14 A. I am among Concentric’s professionals who provide expert testimony before federal,
15 state and Canadian provincial agencies on matters pertaining to economics, finance,
16 and public policy in the energy industry. Concentric provides financial, economic
17 and regulatory advisory services to clients across North America, including utility
18 companies, regulatory and public agencies, and utility sector investors. I regularly
19 advise utilities, generating companies, public bodies and private equity investors on
20 business issues pertaining to the utility industry. This work includes calculating the
21 cost of capital for the purpose of ratemaking, and providing expert testimony and
22 studies on matters pertaining to incentive regulation, rate policy, valuation, capital

1 costs, demand side management, low-income programs, fuels and power markets. In
2 addition, I work for utilities, independent developers and public bodies on issues
3 pertaining to the management and development of power generation, distribution
4 and transmission facilities.

5 I have authored numerous articles on the energy industry and filed testimony before
6 the Federal Energy Regulatory Commission and jurisdictions in Alberta, British
7 Columbia, California, Connecticut, Maine, Massachusetts, New Jersey, Nova Scotia,
8 Ontario, Québec, South Dakota, Texas, Vermont and Wisconsin. I also have co-
9 authored two studies that compare and analyze ROEs for gas and electric utilities in
10 Canada, and I have spoken at industry and regulatory sponsored events on the topic.

11 Prior to joining Concentric, I was Senior Managing Director in the Corporate
12 Economics Practice for FTI/Lexecon, and Managing Director for Arthur
13 Andersen's Energy & Utilities Corporate Finance Practice. In those positions, I
14 provided expert testimony and advisory services on mergers, acquisitions,
15 divestitures and capital markets for clients in the energy industry. In addition to the
16 foregoing positions, I was also Managing Director for Navigant Consulting, with
17 responsibility for the firm's Financial Services practice, Director in DRI's Electric
18 and Natural Gas practices, and Senior Economist for the Massachusetts Energy
19 Facilities Siting Council, where I analyzed the supply plans and facilities proposals
20 from the state's electric and gas utilities. I also served as State Energy Economist for
21 the Maine Office of Energy Resources. I hold a B.S. in Business Administration

1 from Georgetown University and a M.S. in Resource Economics from the University
2 of New Hampshire. My qualifications are more fully detailed in the curriculum vitae.

3 **Q. Please state your name, affiliation, and business address.**

4 A. My name is John P. Trogonoski, and I am also employed by Concentric as a Project
5 Manager. My business address is 293 Boston Post Road West, Suite 500,
6 Marlborough, MA 01752.

7 **Q. Please describe your experience and qualifications.**

8 A. I have approximately 20 years experience in utility regulation, financial analysis,
9 business valuation, property taxation, and program administration. Since joining
10 Concentric in February 2008, I have advised numerous utility and energy clients on a
11 wide range of financial and economic issues with primary concentrations in the
12 determination of the cost of capital for rate-making purposes and an assessment of
13 business, regulatory and financial risk. As a member of the Staff of the Colorado
14 Public Utilities Commission from 1999-2008, I supervised the financial analysts in
15 the energy and telecommunications sections and provided expert testimony on rate
16 of return, revenue requirement, cost allocation, rate design, incentive regulation, and
17 public policy matters. I have a Master's degree in Business Administration and an
18 undergraduate degree in Marketing from the University of Colorado at Denver. My
19 qualifications are more fully detailed in the curriculum vitae.

20 **Q. On whose behalf are you testifying?**

21 A. We are submitting this testimony on behalf of HQD and HQT, divisions of Hydro-
22 Québec, Inc. ("Hydro-Québec").

1 **B. SCOPE OF TESTIMONY**

2 **Q. What is the scope of your testimony in this proceeding?**

3 A. The testimony provides an estimate of the cost of common equity for HQD and
4 HQT for the purpose of establishing the overall rate of return for the 2014 rate year.
5 In order to estimate the cost of equity, Concentric has relied upon analytical tools
6 and data sources normally used for such purposes before regulators in Canada and
7 the U.S., including a risk analysis that compares the business and financial risks of
8 HQD and HQT to proxy groups of Canadian utilities and U.S. electric utilities with
9 similar business and operating profiles as HQD and HQT. Concentric has also
10 reviewed the past decisions and precedents established by the Régie de l'énergie (the
11 “Régie”) in consideration of such matters.

12 The analysis provided in this testimony supports Concentric’s overall
13 recommendation on the cost of equity for ratemaking purposes. That analysis
14 includes the following:

- 15 (1) assessment of HQD’s and HQT’s operating and financial profile;
16 (2) examination of the legal and regulatory requirements for determination of a
17 fair rate of return;
18 (3) selection of Canadian and U.S. proxy groups with companies comparable to
19 HQD and HQT with respect to business and operating risks;

(4) examination of the regulatory, institutional, economic and financial conditions in Canada and the U.S. to address the Régie's prior concerns regarding reliance on a U.S. proxy;¹

(5) examination of the business and financial risks of HQD and HQT relative to the Canadian and U.S. proxy group companies to determine whether it is reasonable to rely on those respective proxy groups to estimate the required ROE for HQD and HQT;

(6) estimation of the cost of equity using well-established financial methodologies – the Capital Asset Pricing Model ("CAPM") and the Discounted Cash Flow ("DCF") method;

(7) development of a range of results for the Canadian and U.S. proxy groups; and

(8) estimation of HQD's and HQT's cost of common equity based on application and interpretation of that range and the business and financial risks of HQD and HQT relative to the respective proxy groups.

C. EXECUTIVE SUMMARY

Q. Please summarize your analyses and conclusions.

A. Concentric has relied upon the following regulatory standards and analyses to reach the following conclusions and recommendations:

¹ Specifically, the Régie has sought evidence that would make it possible to conclude that the regulatory, institutional, economic and financial contexts of the two countries and their impacts on the resulting opportunities for investors are comparable. Régie de l'énergie, Décision D-2011-182, File R-3752-2011, Phase 2, November 25, 2011, at paragraphs [294-295].

1) Established legal and regulatory principles require that HQD and HQT be given an opportunity to earn a fair return on their invested capital.²

2) In order for the rate of return to be judged as fair, the Companies must be provided with a reasonable opportunity to earn a return that meets three requirements:

- Capital attraction requirement
- Financial integrity requirement
- Comparable earnings requirement

These three standards must be met individually and in total in order to satisfy a fair return.³

3) Concentric has estimated the cost of equity for HQD and HQT utilizing both the CAPM and DCF models, with alternative inputs and model specifications designed to test the reasonable range of results. In doing so, we look for evidence of consistency between models and results, and evidence of outlying results that should be questioned.

Due to our concerns regarding the inputs and results from the traditional CAPM, and in consideration of more recent decisions by the Régie that attempt to

² Concentric understands that the Régie adheres to the “just and reasonable” standard for the setting of overall utility rates, consistent with regulatory practice elsewhere in Canada and the U.S. We refer here, specifically to the “Fair Return Standard”, emanating from the decision in *Northwestern Utilities v. City of Edmonton* (1929) [1929] S.C.R. 186 (“Northwestern”), and widely acknowledged as the legal and regulatory standard in Canada for purposes of determining the appropriate cost of capital for regulated utilities.

³ The National Energy Board and provincial regulators have ascribed to these same requirements.

1 account for those problems and differences with other models, Concentric has
2 developed a “Reconciled CAPM” that results in a 9.22 percent ROE.

3 The DCF analysis applied to a proxy group of Canadian utility companies
4 produces a range of ROEs from 9.4 percent to 12.1 percent, with a mean result
5 of 10.7 percent, including flotation costs of 30 basis points. The results of the
6 DCF model using a U.S. electric utility proxy group range from 9.2 percent to 9.6
7 percent, with a mean result of 9.4 percent, including flotation costs of 30 basis
8 points.

9 The results of the methods Concentric has relied upon are summarized in Table
10 1.

11 4) Proxy Groups - It is appropriate to consider Canadian and carefully chosen U.S.
12 proxy groups as benchmarks for electric distribution and transmission utilities,
13 such as HQD and HQT. More specifically, given the small number of publicly-
14 traded Canadian utilities, it is appropriate to consider the analytical results for a
15 group of low-risk U.S. electric utilities. Concentric’s evidence indicates that a
16 carefully-selected group of U.S. electric utility companies is more like HQD and
17 HQT than the Canadian proxy companies due to differences in their business
18 profiles. It is important to note that Concentric does not conclude that all U.S.
19 electric utilities are comparable to HQD and HQT. Our selection of the U.S.
20 electric utility proxy group is based on a careful screening of the universe of U.S.
21 companies to select those most comparable to HQD and HQT. That screening

1 process considers factors such as credit ratings, payment of dividends, market
2 capitalization, percentage of revenues derived from regulated operations and
3 from regulated electric utility operations, and whether the company is involved in
4 a merger/acquisition that materially affected the stock price during the evaluation
5 period. Importantly, Concentric's credit rating screen selects low-risk U.S.
6 electric utilities with long-term issuer ratings from Standard and Poor's ("S&P")
7 of A- or higher. Those credit ratings imply that the rating agencies view these
8 U.S. companies as having relatively low business and financial risks. Concentric
9 ultimately selects six Canadian utilities and six U.S. electric utilities for further
10 risk analysis at the operating company level.

11 5) Risk Factors – Concentric has developed a detailed assessment of the risks of the
12 Canadian and carefully selected U.S. electric utility proxy companies with respect
13 to economic conditions, the integration of financial markets, government and
14 regulatory policies, and business and financial risks. The following summarizes
15 the conclusions of our risk analysis.

- 16 • Investment Risk – More than ever, Canada and the United States are
17 similar from an investment perspective. Specifically, it is reasonable
18 to conclude that investors would not find material differences in
19 economic, financial and regulatory conditions between Canada and
20 the U.S. that would cause them to assign a different risk profile to
21 Canadian and U.S. companies that are otherwise comparable.

1 • Business Risk – Both Canadian and U.S. regulators have provided the
2 operating companies in the proxy groups with cost recovery and
3 revenue stabilization mechanisms that mitigate many of the
4 important business risks, such fuel supply, fluctuations in
5 volume/demand, capital investment costs, and operating costs that
6 tend to fluctuate significantly from year to year. Based on the
7 business risks identified in this testimony, the only important
8 difference is that a percentage of electric utilities in the U.S. proxy
9 group (and in Canada) own some regulated generation, which
10 suggests that those companies have somewhat more business risk
11 than HQD and HQT.

12 • Financial Risk – HQD and HQT have somewhat more financial
13 leverage in their capital structures than the Canadian utilities and
14 substantially more financial leverage and weaker credit metrics than
15 the U.S. electric utility proxy group companies. Credit rating agencies
16 may be satisfied with the degree of regulatory protection and cash
17 flow protection for debt investors, but these metrics expose equity
18 investors to greater risk than their U.S. counterparts. As such, HQD
19 and HQT have greater financial risk than the U.S. electric utility
20 proxy group, which more than offsets the ownership of regulated
21 generation described above.

1 6) Recommended ROE – The results produced from the various methods and
2 inputs cover a broad spectrum. This is not surprising considering the range of
3 inputs and techniques employed and recent unprecedented market conditions.
4 All methods are not, however, producing a reasonable estimate for HQD's and
5 HQT's cost of equity.

6 Specifically, Concentric has concerns with the ability of the CAPM to produce
7 reasonable results in light of the factors affecting the inputs at this time. Bond
8 yields in Canada and the U.S. have been driven to all time lows, and most would
9 agree below sustainable levels in the longer term. As a result of the financial
10 crisis and recession, utility betas have also been impacted, and market equity risk
11 premium estimates cover a broad spectrum. There is a substantial gap between
12 historic equity returns and the higher returns implied in current stock market
13 data. These are problems with the CAPM, and in general, in the current market
14 environment.

15 As shown in Table 1 and described in the CAPM section, Concentric has
16 attempted to reconcile for these differences using logic employed by the Régie in
17 the past. We began with a Canadian risk free rate. The market risk premium is a
18 combination of both Canadian and U.S. market inputs, including both historical
19 and forward-looking estimates. The beta is derived from the U.S. electric utility
20 proxy group. Concentric finds that a carefully-selected U.S. electric utility proxy
21 group is more representative of HQD and HQT than the Canadian companies;
22 therefore, the beta from the U.S. companies is more representative. Flotation

1 costs are included consistent with the Régie's past decisions, and finally,
2 Concentric makes a 75 basis point adjustment for differences between the
3 CAPM results and the DCF model. This reconciliation is consistent with the
4 Régie's approach in factoring in an adjustment for the "Results of Other
5 Models" in the 2012 Gaz Métro rate case. The reconciled CAPM results of 9.22
6 percent offer a view into the required adjustment to inputs to achieve a
7 reasonable result in the current environment.

8 Under current market conditions, Concentric believes greater weight should be
9 given to the DCF model. The average of our DCF method for the U.S. proxy
10 group produces a relatively tight range of 9.20 percent to 9.58 percent, with an
11 average of 9.41 percent. The Canadian DCF produces a range of 9.38 percent to
12 12.05 percent, with an average of 10.71 percent. Placing principal reliance on the
13 DCF model with U.S. electric utility proxy companies and selecting the lower
14 end of the range for the lack of generation risk (even though we have not made
15 any offsetting adjustment for higher financial risk) the estimated cost of equity
16 for HQD and HQT is 9.2 percent. This recommended ROE is supported by the
17 range of analytical results produced by the DCF analyses for both the Canadian
18 and U.S. electric utility proxy groups, and can be reconciled with the CAPM with
19 appropriate adjustments.

1 Application of the traditional CAPM formula, not including flotation costs, using
2 the Canadian proxy group would produce an ROE of 7.81 percent.⁴ This return
3 would not be within the reasonable range of ROE estimates, and in Concentric's
4 opinion would not meet the measures of a fair return. In addition, it would not
5 be consistent with the stand-alone principle, which requires the allowed ROE for
6 HQD and HQT to be set at a level as if the companies were independently going
7 to the equity markets to raise capital.

⁴ See Exhibit JMC-6.

1

Table 1: Summary of Results

Capital Asset Pricing Model				
Inputs		CAPM Reconciled		
Risk Free Rate		4.23%		
Beta		0.59		
Market Risk Premium		6.67%		
Sub-Total		8.17%		
Flotation Cost		0.30%		
Sub-Total		8.47%		
Adjustment for Other Models		0.75%		
Total		9.22%		
Discounted Cash Flow				
Market Averaging Period	Constant Growth	Sustainable Growth	Multi-Stage	Average
Canadian Utility Proxy Group				
Average ROE	11.75%	N/A	9.08%	10.41%
Flotation Cost	0.30%	N/A	0.30%	0.30%
Average ROE with Flotation Cost	12.05%		9.38%	10.71%
U.S. Electric Utility Proxy Group				
Average ROE	9.28%	8.90%	9.14%	9.11%
Flotation Cost	0.30%	0.30%	0.30%	0.30%
Average ROE with Flotation Cost	9.58%	9.20%	9.44%	9.41%

2

3 In response to the Régie's previous concerns with relying on market-based returns
4 for U.S. utilities to estimate the allowed ROE, Concentric also presents an analysis of
5 the allowed and earned ROEs for the U.S. proxy group at the operating company

1 level from 2000-2011. That analysis demonstrates that it is reasonable and
2 appropriate to conclude that operating utilities in the U.S. electric utility proxy group
3 have earned their authorized ROE in the vast majority of instances over that twelve
4 year period. From this perspective, the evidence suggests that the regulatory regimes
5 in these U.S. jurisdictions have generally provided utilities with timely cost recovery,
6 which in turn, gives utilities and their investors a reasonable opportunity to earn their
7 allowed ROE.

8 **Q. How is the remainder of your testimony organized?**

9 A. The remainder of the testimony is organized as follows. Section II provides an
10 overview of HQD's and HQT's operations. Section III discusses the legal
11 requirements and regulatory precedents for the determination of a fair rate of return.
12 Section IV describes the criteria used to select proxy groups in order to estimate the
13 cost of equity for HQD and HQT. Section V discusses the precedent in Canada for
14 considering the use of U.S. data and proxy groups to establish the allowed ROE for
15 a Canadian utility. Section VI presents a comparison of the business and economic
16 conditions in Canada and the U.S. Section VII discusses the business and financial
17 risks of the companies in the Canadian and U.S. proxy groups (at the operating
18 company level) relative to HQD and HQT. Section VIII provides an analysis of
19 earned and authorized returns for the Canadian and U.S. proxy groups as compared
20 to HQD and HQT. Section IX discusses the various methods used to estimate the
21 cost of equity and their reliability under current market conditions, and summarizes
22 the results of the CAPM and DCF analyses. Section X summarizes our results and
23 recommendations.

1 **II. PROFILE OF HQD AND HQT**

2 **Q. Please describe the operations of HQD and HQT.**

3 A. HQD is the electricity distribution division of Hydro Québec, serving roughly four
4 million customers. The division operates a distribution system comprising 113,525
5 km of lines and five distribution control centers; the division also has a small amount
6 of generation capacity to supply customers on off-grid systems.⁵ In 2011, HQD
7 reported revenue of \$10.8 billion and \$8.9 billion in property, plant, and equipment.⁶
8 In 2011, HQD made \$950 million in investments in property, plant, equipment, and
9 intangible assets (including its energy efficiency plan).⁷ In 2011, HQD derived
10 approximately 31 percent of its revenue from industrial customers.⁸

11 HQT is the electricity transmission division of Hydro Québec. HQT's customers
12 consist primarily of HQD for native load transmission service and North American
13 wholesalers that use point-to-point transmission services. HQT operates the largest
14 power transmission system in North America with 33,630 kilometers of lines, and
15 514 substations.⁹ In addition, the system includes 15 interconnections allowing
16 energy interchanges with the Maritime provinces, Ontario and the U.S. Northeast.
17 As of 2011, the fixed assets of HQT were \$17.6 billion, including \$0.9 billion under
18 construction. In 2011, HQT had revenues of \$3.1 billion, net income of \$435

⁵ Hydro-Québec Annual Report, 2011, at p. 20.

⁶ Ibid.

⁷ Ibid.

⁸ Ibid.

⁹ Hydro-Québec Annual Report, 2011, at p. 114.

1 million and invested \$1.3 billion in its transmission system.¹⁰ Over the past five
2 years, HQT has invested a total of \$5.7 billion.

3 **Q. How do credit rating agencies view Hydro-Québec?**

4 A. Neither HQD nor HQT issue their own debt. Hydro-Québec, the parent company
5 of HQD and HQT, has investment grade ratings from each of the credit rating
6 agencies; the Company's current corporate credit rating is A+ (outlook: stable) from
7 S&P, Aa2 (outlook: stable) from Moody's Investors Service ("Moody's") and A
8 (high) (outlook: stable) from DBRS.¹¹ Hydro-Québec's debt is guaranteed by the
9 Province of Québec, meaning that HQ's credit rating is linked to the rating of the
10 provincial government. The cost of the government debt guarantee has previously
11 been estimated by Merrill Lynch at approximately 50 basis points.¹²

12 Moody's notes: "HQ's T&D assets operate in a supportive, stable regulatory
13 environment with limited regulatory lag. However, HQ's allowed ROE and deemed
14 equity ratio are low in comparison to other Canadian utilities and international
15 peers."¹³ On the issue of financial leverage, DBRS comments: "Although the
16 Province unconditionally guarantees almost all outstanding debt, high debt levels
17 nevertheless result in a higher interest expense, thus constraining profitability and
18 resulting in weaker interest coverage ratios."¹⁴ With respect to capital spending,
19 DBRS notes: "As outlined in its *Strategic Plan 2009-2013*, Hydro-Québec is

¹⁰ Hydro-Québec Annual Report, 2011, at p. 14.

¹¹ Source: SNL Financial.

¹² "Opinion Regarding Hydro-Québec's Theoretical Borrowing Costs in the Absence of a Government Guarantee," Merrill Lynch & Co. Ratings Advisory Group, prepared by Brian Keegan, August 2000, at p. 3

¹³ Moody's Investors Service, Credit Opinion: Hydro-Québec, August 6, 2012, at p. 2.

¹⁴ DBRS Rating Report, Hydro-Québec, April 12, 2012, at p. 2.

1 undergoing a substantial capital expenditure (capex) program which calls for an
2 increase in debt levels, leading to weaker credit metrics.”¹⁵

3 **III. DETERMINATION OF A FAIR RETURN**

4 **Q. What are the key legal and regulatory precedents in Canada and the U.S.?**

5 A. The principles surrounding the concept of a “fair return” for a regulated company
6 were established by the Supreme Court of Canada in the *Northwestern Utilities v. City of*
7 *Edmonton* (1929) (“Northwestern”) case, where the Supreme Court found:

8 By a fair return is meant that the company will be allowed as large a
9 return on the capital invested in its enterprise (which will be net to
10 the company) as it would receive if it were investing the same amount
11 in other securities possessing an attractiveness, stability and certainty
12 equal to that of the company’s enterprise.¹⁶

13 As stated by Major and Priddle in 2008, this definition remains in full legal effect
14 today.¹⁷

15 United States law regarding fair return for utility cost of capital has evolved similarly.
16 The U.S. Supreme Court set out guidance in the bellwether cases of *Bluefield Water*
17 *Works* and *Hope Natural Gas Co.* as to the legal criteria for setting a fair return. In
18 *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia*
19 (262 U.S. 679, 693 (1923)), the Court found:

20 The return should be reasonably sufficient to assure confidence in
21 the financial soundness of the utility and should be adequate, under
22 efficient and economical management, to maintain and support its

¹⁵ Ibid, at p. 1.

¹⁶ *Northwestern* at p. 186.

¹⁷ *The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results, Implications*, by The Honourable John C. Major, Former Justice, Supreme Court of Canada, and Roland Priddle, President, Roland Priddle Energy Consulting Inc., Former Chair of the National Energy Board, March 2008, at p. 4.

1 credit and enable it to raise the money necessary for the proper
2 discharge of its public duties. A rate of return may be reasonable at
3 one time and become too high or too low by changes affecting
4 opportunities for investment, the money market and business
5 conditions generally.

6 The U.S. Court further elaborated on this requirement in its decision in *Federal Power*
7 *Commission v. Hope Natural Gas Company* (320 U.S. 591, 603 (1944)). There the Court
8 described the relevant criteria as follows:

9 From the investor or company point of view it is important that
10 there be enough revenue not only for operating expenses but also for
11 the capital costs of the business. These include service on the debt
12 and dividends on the stock [...] By that standard the return to the
13 equity owner should be commensurate with returns on investments
14 in other enterprises having corresponding risks. That return,
15 moreover, should be sufficient to assure confidence in the financial
16 integrity of the enterprise, so as to maintain its credit and to attract
17 capital.

18 With the passage of time, the Fair Return Standard has been interpreted many times
19 in both Canada and the U.S. The National Energy Board (“NEB”) summarized its
20 interpretation of the “fair return standard” in its RH-2-2004 Phase II Decision and
21 more recently reiterated that interpretation in its *Trans Québec & Maritimes Pipelines Inc.*
22 RH-1-2008 Decision, at pp. 6-7.

23 The Board is of the view that the fair return standard can be
24 articulated by having reference to three particular requirements.
25 Specifically, a fair or reasonable return on capital should:

- 26 • be comparable to the return available from the application of the
27 invested capital to other enterprises of like risk (the comparable
28 investment standard);
- 29 • enable the financial integrity of the regulated enterprise to be
30 maintained (the financial integrity standard); and

- permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).

In the Board's view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline's revenue requirement, result in tolls that are just and reasonable.¹⁸

Similarly, the Ontario Energy Board ("OEB") has discussed the necessity of adhering to the fair return standard as follows:

The Board affirms its view that the Fair Return Standard frames the discretion of a regulator, by setting out the three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. Notwithstanding this obligation, the Board notes that the Fair Return Standard is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.¹⁹

... all three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate comparability to the comparable investment test is not sufficient to meet the [Fair Return Standard].²⁰

Q. Has the Régie adopted the same legal standards for application of the fair return standard as those described above?

¹⁸ National Energy Board RH-2-2004 Reasons for Decision, TransCanada PipeLines Ltd, Phase II, April 2005, at p. 17.

¹⁹ Ontario Energy Board, EB-2009-084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at i.

²⁰ Ibid., at p. 19.

1 A. Yes. The Régie embraces the same legal standards for the application of the fair
2 return standard as those put forth by the NEB, the OEB and those established
3 through Canadian and U.S. law. The Régie recognizes the three primary criteria of
4 the fair return standard (i.e., the comparability standard, the financial integrity
5 standard, and the capital attraction standard) and has indicated that these should be
6 used as a guide in exercising its role with respect to fixing a reasonable rate of
7 return.²¹ In addition, the Régie has indicated that its duty is to determine a
8 reasonable rate of return, and the method which it uses is at its discretion.²² The
9 Régie has also recognized that, like operating costs, the return allowed to the
10 shareholder is one of the elements of the regulated company's cost of service. The
11 allowed return must, under the official Act²³ governing utility regulation, ensure that
12 there are sufficient revenues to cover all of the costs.²⁴

13 **Q. Are there other key principles that Canadian regulators have adopted with**
14 **regard to establishing a fair return on equity?**

15 A. Yes. Canadian regulatory authorities have determined that another key principle in
16 establishing a fair return on equity for a regulated utility is the “stand-alone”
17 principle. The Régie has indicated in prior decisions that the ROE for HQD and
18 HQT should be set on a “stand-alone” basis, as if the entities were independently
19 seeking to attract capital in the financial markets.²⁵

²¹ Régie de l'énergie, Décision D-2009-156 (R-3690-2009), Gaz Métro, (December 7, 2009), at para [189].

²² Ibid., at para [195].

²³ R.S.Q., chapter R-6.01, An Act respecting the Régie de l'énergie (“the Act”) empowers the Régie to set rates for regulated energy utilities in Québec.

²⁴ Régie de l'énergie, Décision D-2009-156 (R-3690-2009), Gaz Métro, (December 7, 2009), at para [192].

²⁵ Régie de l'énergie, Décision D-2002-95 (R-3401-98), Hydro Québec-TransÉnergie, (April 30, 2002) at p. 163, and Décision D-2003-93 (R-3492-2002), Hydro-Québec Distribution (May 21, 2003), at p. 70.

Q. Please summarize the history of the authorized return on equity for HQD and HQT.

A. The Régie first established authorized ROEs for HQD and HQT for rate years 2004 and 2001, respectively.²⁶ For both HQD and HQT, the Régie has consistently established the authorized ROE according to the following formula:

$$\text{Authorized ROE} = \text{Risk Free Rate} + \text{Company-specific Risk Premium}$$

Each year, the Régie has adjusted the authorized ROEs according to the formula based on the latest forecasted risk free rate from *Consensus Forecasts*. Table 2 shows the authorized ROEs for HQD and HQT over time.

Table 2: Authorized ROEs for HQD and HQT

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
HQD	--	--	--	9.06	8.71	7.96	7.57	7.74	6.98	7.85	7.32	6.37
HQT	9.66	9.66	9.66	9.66	8.59	8.59	7.50	7.85	7.63	7.59	7.14	6.39

IV. SELECTION OF PROXY COMPANIES

Q. Why is it necessary to select a proxy group to estimate the fair return on equity for HQD and HQT?

A. Since the ROE is a market-based concept, and given the fact that HQD and HQT are divisions of Hydro-Québec, a government-owned crown corporation that is not publicly-traded, it is necessary to establish a group of companies that are both publicly-traded and comparable to HQD and HQT in certain fundamental business and financial respects to serve as a “proxy” for purposes of the ROE estimation process.

²⁶ Régie de l'énergie, Decisions D-2002-95 and D-2003-93.

1 Even if HQD's and HQT's regulated electric distribution and transmission
2 operations made up the entirety of a publicly-traded entity, it is possible that
3 transitory events could bias those entities' market value in one way or another over a
4 given period of time. A significant benefit of using a proxy group, therefore, is the
5 ability to mitigate the effects of anomalous events that may be associated with any
6 one company. As demonstrated later in this testimony, the proxy companies used in
7 the ROE analyses possess a set of business and operating characteristics that make
8 them similar to HQD's and HQT's regulated distribution and transmission
9 operations, and thus provide a reasonable basis for the derivation and assessment of
10 ROE estimates.

11 **Q. Does the careful selection of a proxy group suggest that analytical results will**
12 **be tightly clustered around average results?**

13 A. Not necessarily. Notwithstanding the care taken to ensure risk comparability, market
14 expectations with respect to future risks and growth opportunities will vary from
15 company to company. Therefore, even within a group of similarly situated
16 companies, it is common for analytical results to reflect a seemingly wide range. At
17 issue, then, is how to select an ROE estimate in the context of that range. That
18 determination must be based on an assessment of the company-specific risks relative
19 to the proxy group and the informed judgment and experience of the analyst.

1 **Q. Why has Concentric developed three proxy groups?**

2 A. Since the purpose of this proceeding is to establish the allowed ROE for the
3 regulated electric distribution and transmission operations of HQD and HQT,
4 respectively, and because there are very few publicly-traded, pure-play electric utilities
5 in Canada, Concentric has selected a sample of Canadian utilities to provide a
6 benchmark for the resulting cost of equity of Canadian utilities in general. Then, in
7 order to gain additional perspective on the cost of equity and risks specific to electric
8 distribution and transmission utilities, we have developed a sample of U.S.
9 companies that are primarily engaged in the provision of electric utility service.
10 Finally, to provide additional perspective, Concentric has compared the authorized
11 returns of HQD and HQT against a group of Canadian government-owned electric
12 utilities.

13 **Q. Please describe how Concentric selected the Canadian proxy group.**

14 A. Concentric developed a group of publicly-traded regulated Canadian electric and
15 natural gas utility companies. Because there are relatively few companies in that
16 sector in the Canadian public market, no specific screening criteria were used to
17 derive the proxy group. The following six companies comprise the Canadian Utility
18 Proxy Group:

- 19 • Canadian Utilities Limited
- 20 • Emera, Inc.
- 21 • Enbridge, Inc.
- 22 • Fortis, Inc.

- TransCanada Corporation
- Valener, Inc.

Q. How did you select the group of U.S. electric utility proxy companies that are risk appropriate for HQD and HQT?

A. To establish the group of U.S. electric utility proxy companies that are risk appropriate for HQD and HQT, Concentric relied on screening criteria to narrow the list of potential proxy companies. As HQD's and HQT's business operations are 100 percent electric, an evaluation of the potential proxy companies' business units was conducted to identify a group of comparable risk companies to HQD and HQT.

As a starting point, Concentric utilized the 48 companies that Value Line classifies as Electric Utility Companies to ensure that the company is considered to be primarily engaged in electric utility operations. From that group, Concentric screened for companies that:

- Have credit ratings of at least A- from S&P;
- Pay dividends;
- Have earnings growth rates from at least two utility industry analysts;
- Derived at least 60 percent of their revenue from regulated operations in the period from 2009-2011;
- Derived at least 60 percent of their regulated revenue from electric utility operations in the period from 2009-2011;
- Are not considered a small capitalization company; and

- 1 • Are not involved in a merger or other transformative transaction that had a
- 2 material effect on the company's stock price during the evaluation period.

3 **Q. What companies met those screening criteria?**

4 A. The following six companies met those criteria:

- 5 • Consolidated Edison Inc.
- 6 • NextEra Energy, Inc.
- 7 • Northeast Utilities
- 8 • Southern Company
- 9 • Wisconsin Energy Corp.
- 10 • Xcel Energy Inc.

11 **Q. Did you also consider a third proxy group of government-owned electric**
12 **utilities in Canada?**

13 A. Yes. Since HQD and HQT are divisions of a government-owned crown
14 corporation, Concentric also selected a group of municipal and provincial
15 government-owned Canadian electric distribution and transmission utilities for
16 purposes of comparing the authorized ROE of HQD and HQT to those entities.

17 That group consists of the following six companies:

- 18 • British Columbia Hydro
- 19 • ENMAX Corp.
- 20 • EPCOR Utilities, Inc.
- 21 • Hydro One Networks

- Manitoba Hydro
- Saskatchewan Power

Q. What is the importance of your credit rating screen?

A. Credit ratings are based on the utility's business risk profile (which includes an assessment of the regulatory environment in which the utility operates) and its financial risk profile. Companies with similar credit ratings have been determined by the rating agency to have similar levels of business and financial risk. This concept has been adopted by regulatory agencies, including the Federal Energy Regulatory Commission ("FERC"), which has found that "it is reasonable to use the proxy companies' corporate credit rating as a good measure of investment risk, since this rating considers both financial and business risk."²⁷

The Régie has also recognized in previous decisions that credit ratings are an important indicator of business and financial risk. Specifically, in a 2011 Gaz Métro decision, the Régie stated: "The Régie considers the credit rating information contained in the S&P Utility Report, particularly with respect to regulated natural gas distribution activities in Québec, to be relevant information that the market uses in assessing Gaz Métro's risk..."²⁸

Concentric's credit rating screen selects U.S. electric utility companies with credit ratings of A- or higher, thereby taking into consideration the business and financial risk profile of those utility companies. The basis for choosing proxy group

²⁷ See, for example, *Potomac-Appalachian Transmission Highline, LLC*, 122 FERC ¶ 61,188 at P 97 (2008).

²⁸ Régie de l'énergie, Décision D-2011-182, File R-3752-2011, Phase 2, Gaz Métro, November 25, 2011, at paragraphs [294-295]. English translation.

1 companies with credit ratings of A- or higher is that absent the government debt
2 guarantee, the credit rating for Hydro-Québec would be several notches lower.²⁹
3 Selecting a proxy group of low-risk U.S. electric utility companies with credit ratings
4 of A- or higher minimizes the need to adjust the U.S. results to account for
5 perceived differences in business or financial risk between those U.S. companies and
6 HQD and HQT. To reinforce this conclusion, Concentric has evaluated the
7 business and financial risks of HQD and HQT in relation to the operating
8 companies within the Canadian and U.S. proxy groups.

9 **Q. Are any of the utilities in the Canadian and U.S proxy groups engaged in non-**
10 **regulated operations, and, if so, how does that affect the choice of the**
11 **appropriate proxy group?**

12 A. Yes. Regulated utilities are typically part of a holding company structure, which may
13 also include non-regulated business activities. In particular, several companies in the
14 Canadian utility proxy group have affiliates that are engaged in non-regulated
15 activities or in regulated activities other than electric distribution and transmission.
16 As shown on Exhibit JMC-1, in 2011, the average company in the Canadian utility
17 proxy group derived approximately 61 percent of its operating income from
18 regulated utility operations and 59 percent of its revenues from regulated utility
19 service.³⁰ Two companies, however, have substantial non-electric and/or
20 unregulated operations, which have different business risks than the regulated

²⁹ In August 2012, Moody's Investors Service indicated that its Baseline Credit Assessment for Hydro-Quebec would be Baa1 (S&P equivalent BBB+) absent the government debt guarantee from the Province of Quebec. See Moody's credit report for Hydro-Québec, issued August 6, 2012, at p. 2.

³⁰ This percentage does not include income or revenue from gas transmission service.

1 electric transmission and distribution business. The extent of non-electric utility
2 activities and non-regulated activities at Enbridge, Inc. and TransCanada Corp.
3 underscores the benefit of using a proxy group of U.S. electric utilities to estimate
4 the cost of equity for HQD and HQT, supplemented by the results for the Canadian
5 proxy group.

6 Non-regulated operations are not a significant concern for the U.S. electric utility
7 proxy group because, as also shown on Exhibit JMC-1, regulated electric utility
8 service represented approximately 86 percent of operating income and 92 percent of
9 revenues for the U.S. proxy group companies in 2011. Furthermore, Concentric
10 conducts the risk analysis at the operating company level, so that the risk comparison
11 reflects the operations of the regulated utilities. This approach enables comparisons
12 between utilities, while mitigating concerns that the results are unduly influenced by
13 the non-regulated activities of the parent holding companies.

14 **V. PRECEDENT FOR CONSIDERING U.S. DATA**

15 **Q. Has the Régie considered the use of U.S. data as it relates to setting the return**
16 **on equity for regulated utilities in Québec?**

17 A. Yes. The Régie has recently given equal weight to U.S. data in estimating the market
18 risk premium. In a 2009 Order, the Régie stated:

19 With respect to the weighting of Canadian and U.S. data to be used
20 in estimating the market risk premium, the Régie, in Decision D-99-
21 150, established a weight of 60% for Canadian data and 40% for U.S.
22 data. *Based on the evidence in this case, the Régie bases its estimate of the*
23 *market risk premium using equal portions of Canadian and U.S. data.* It
24 considers that the opening of markets offers investors various
25 investment options such that it is necessary to reflect the situation in

1 establishing a reasonable rate of return. It also justifies greater
2 consideration of U.S. data because of the increasing integration of the
3 two economies.³¹

4 The Régie, however, has also indicated that applicants have not provided a sufficient
5 basis to conclude that it was reasonable to consider U.S. proxy group results to
6 estimate the cost of equity for natural gas or electric utilities in Québec. Specifically,
7 the Régie has expressed concerns with the evidence that has been presented in
8 previous cases with respect to the use of U.S. proxy groups and the use of authorized
9 returns for regulated utilities in the U.S. as a relevant benchmark for Canadian
10 electric and natural gas utilities. Among the specific concerns cited by the Régie are
11 the following:

- 12 • The Régie believes that the distributor has not demonstrated that the
13 opportunities on the U.S. market are comparable in terms of risk.³²
- 14 • The Régie has not been persuaded that the regulatory, institutional,
15 economic and financial contexts of the two countries and their impacts
16 on the resulting opportunities for investors are comparable.³³
- 17 • The Régie has found that the evidence has not been very convincing
18 regarding the reasons that would justify relying on authorized returns in
19 the U.S. as a reference point for the rates to allow in Québec.³⁴

³¹ English translation of Régie de l'énergie, Décision D-2009-156 (R-3690-2009), Gaz Métro, December 7, 2009, at paragraph [249]. [Emphasis added]

³² English translation of Régie de l'énergie, Décision D-2011-182 (R-3752-2011, Phase 2), Gaz Métro, November 25, 2011, at paragraph [270].

³³ Ibid., at paragraphs [294-295].

³⁴ Ibid., at paragraph [270].

- The Régie has indicated that a relevant aspect of the risk assessment is a comparison between the authorized and realized returns of regulated U.S. companies with comparable risk, over a long period, and limited to the regulated operations of the companies in the sample.³⁵

Q. Is there precedent among other Canadian regulators for considering U.S. data and a U.S. proxy group to estimate the cost of equity for a Canadian utility?

A. Yes, there is. In recent orders, other Canadian regulators have determined that it is appropriate to consider the use of U.S. data and U.S. proxy groups to estimate the allowed ROE for a Canadian regulated utility. Regulators in Canada have noted several reasons that support consideration of U.S. data. First, the development of a proxy group comprised entirely of Canadian electric utilities is difficult due to the small number of publicly-traded utilities in Canada and the fact that many of those Canadian companies derive a significant percentage of their revenues and net income from operations other than the provision of regulated electric utility service. Second, this problem has been exacerbated by the continuing trend toward mergers and acquisitions in the utility industry, both within Canada and across the border with U.S. utility companies.

The question for Canadian regulators has become: How do we account for any differences in risk between U.S. and Canadian utilities? Concentric's research and analysis demonstrates that it is possible to select a group of U.S. electric utilities that is comparable to HQD and HQT in terms of business and operating risk. In that

³⁵ Ibid., at paragraph [271].

1 regard, Concentric agrees with the conclusion of the OEB that it is not necessary to
2 find that utilities are the *same*, only that they are *comparable*,³⁶ and with the NEB
3 conclusion that it is possible to account for differences in risk that would influence
4 an investor's required rate of return.³⁷

5 **Q. Please summarize the recent orders in which Canadian regulators have**
6 **accepted the use of U.S. data to estimate the cost of equity for a regulated**
7 **utility in Canada.**

8 A. A growing number of Canadian utility regulators have accepted the use of U.S. data
9 or U.S. proxy groups in recent years. For example, in its TQM Decision, the NEB
10 found that U.S. market returns are relevant to the cost of capital for Canadian firms,
11 and that the regulatory regimes in Canada and the U.S. are sufficiently similar as to
12 justify comparison. The NEB appears to view U.S. market returns as valuable
13 information in establishing the cost of capital for Canadian utilities. Moreover, the
14 NEB found that Canadian utilities are competing for capital in global financial
15 markets that are increasingly integrated. The NEB recognized that it is no longer
16 possible to view Canada as insulated from the remainder of the investing world, and
17 that doing so would be detrimental to the ability of Canadian utilities to compete for
18 capital.³⁸ These findings suggest that it is reasonable and appropriate to consider a
19 proxy group of U.S. utility companies as sufficiently comparable to Canadian
20 regulated utilities in terms of their risk profile. Importantly, the NEB also found that

³⁶ Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at p. 21.

³⁷ National Energy Board, Reasons for Decision, TQM RH-1-2008 (March 2009), at p. 71.

³⁸ National Energy Board, Reasons for Decision, TQM RH-1-2008 (March 2009), at p. 66-72.

1 the regulatory regimes in the U.S. and Canada were sufficiently similar as to justify
2 comparison between utilities in the two countries, stating:

3 The Board is not persuaded that the U.S. regulatory system exposes
4 utilities to notable risks of major losses due either to unusual events
5 or cost disallowances. The Board views the losses and disallowances
6 experienced by U.S. regulated entities as a result of the restructuring
7 that took place to terminate the merchant gas function of pipelines,
8 as well as some other circumstances such as the Duquesne nuclear
9 build, to be, to a large extent, unique events. The Board also finds
10 that such instances are not likely to weigh significantly in investors'
11 perceptions today, and would thus have little or no impact on cost of
12 capital.³⁹

13 Likewise, the OEB concluded that the U.S. is a relevant source of comparable data
14 and that it often looks to the U.S. to inform its decisions:

15 The Board is of the view that the U.S. is a relevant source for
16 comparable data. The Board often looks to the regulatory policies of
17 State and Federal agencies in the United States for guidance on
18 regulatory issues in the province of Ontario. For example, in recent
19 consultations, the Board has been informed by U.S. regulatory
20 policies relating to low income customer concerns, transmission cost
21 connection responsibility for renewable generation, and productivity
22 factors for 3rd generation incentive ratemaking.

23
24 Finally, the Board agrees with Enbridge that, while it is possible to
25 conduct DCF and CAPM analyses on publicly-traded Canadian utility
26 holding companies of comparable risk, there are relatively few of
27 these companies. As a result, the Board concludes that North
28 American gas and electric utilities provide a relevant and objective
29 source of data for comparison.⁴⁰

30 Finally, the British Columbia Utilities Commission ("BCUC") accepted the use of
31 U.S. data, stating:

³⁹ Ibid.

⁴⁰ Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at p. 23.

1 In addition, the Commission Panel continues to be prepared to
2 accept the use of historical and forecast data of U.S. utilities when
3 applied: as a check to Canadian data, as a substitute for Canadian data
4 when Canadian data do not exist in significant quantity or quality, or
5 as a supplement to Canadian data when Canadian data gives
6 unreliable results. Given the paucity of relevant Canadian data, the
7 Commission Panel considers that natural gas distribution companies
8 operating in the US have the potential to act as a useful proxy in
9 determining TGI's capital structure, ROE, and credit metrics.⁴¹

10 In summary, regulatory authorities in Canada have recognized that Canadian utility
11 companies are competing for capital in global financial markets and that Canadian
12 data is often limited by the small number of publicly-traded utilities. They have also
13 recognized the integrated nature of Canadian and U.S. financial markets, and the
14 similarity of the utility regulatory regimes. Therefore, they have determined that it is
15 reasonable and appropriate to consider the results of a risk-comparable U.S. proxy
16 group for purposes of establishing the allowed ROE for a Canadian natural gas or
17 electric utility.

18 **Q. How have you addressed the Régie's previous concerns with the use of a U.S.**
19 **proxy group to estimate the ROE for regulated utilities in Québec such as**
20 **HQD and HQT?**

21 A. The following sections of the testimony address each of the specific concerns
22 expressed by the Régie, starting with the comparability of business and economic
23 conditions in Canada and the U.S., followed by a detailed assessment of the business
24 and financial risks of HQD and HQT relative to the Canadian and U.S. proxy

⁴¹ British Columbia Utilities Commission, In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., Return on Equity and Capital Structure, Decision G-158-09, December 16, 2009, at pp. 15-16.

1 groups, and a comparison of the earned and authorized ROEs for the U.S. electric
2 utility proxy group at the operating company level.

3 **VI. BUSINESS AND ECONOMIC CONDITIONS IN CANADA AND THE U.S.**

4 **Q. How is the fair return standard affected by the business and economic climate**
5 **for utilities in Canada and the U.S.?**

6 A. In order for utilities to fund their operations on a stand-alone basis, they must be
7 able to attract capital on reasonable terms and conditions from investors with a
8 broad array of alternative investment options (the capital attraction standard). In
9 order to do so, utilities must offer returns that are comparable to enterprises of
10 similar risk (the comparable investment standard). These elements of capital
11 attraction and comparability of investment risk cannot be separated from the
12 business and economic environment that frames capital market and investor
13 expectations. In a world of increasingly linked economies and capital markets,
14 investors seek returns from a global basket of investment options. Investors
15 consider risks on a country-to-country basis, factoring in the comparability of the
16 economies and the business environments.

17 **Q. Has Concentric evaluated the relative economic and business conditions in**
18 **Canada and the U.S. that affect investment risk?**

19 A. Yes. Country-specific economic and business conditions that affect investment risk
20 may be measured through a variety of qualitative and quantitative metrics. One such
21 measure, produced by the Economist Intelligence Unit (affiliated with the *Economist*

1 magazine), provides a ranking of the world's largest economies based on a range of
2 factors impacting the business environment. According to that report:

3 The business rankings model measures the quality or attractiveness of
4 the business environment in the 82 countries covered by *Country*
5 *Forecasts* using a standard analytical framework. It is designed to
6 reflect the main criteria used by companies to formulate their global
7 business strategies, and is based not only on historical conditions but
8 also on expectations about conditions prevailing over the next five
9 years.

10 ***

11 The business rankings model examines [91 indicators] in ten separate
12 criteria or categories, covering the political environment, the
13 macroeconomic environment, market opportunities, policy towards
14 free enterprise and competition, policy towards foreign investment,
15 foreign trade and exchange controls, taxes, financing, the labor
16 market and infrastructure.⁴²

17 The business environment ranks are updated annually in individual country forecasts.
18 Based on the April 2012 update, which provides both the historical 2007-2011 rank
19 and the projected 2012-2016 rank for 82 countries, Canada and the U.S. are ranked
20 4th and 5th respectively over the historic period, and 5th and 9th over the projected
21 five years.⁴³ This report suggests that from a business investment perspective,
22 Canada and the U.S. are highly comparable in a global context.

23 The World Economic Forum ("WEF") also publishes its annual Global
24 Competitiveness Report, which ranks 144 countries on twelve economic factors,
25 including institutions, infrastructure, the macroeconomic environment, health and
26 primary education, higher education and training, goods market efficiency, labor

⁴² "World Investment Prospects to 2011", The Economist Intelligence Unit, written with the Columbia Program on International Development, 2007 Edition, at pp. 38, 39, 235.

⁴³ The Economist Intelligence Unit, Country Forecast United States Updater April 2012, and Country Forecast Canada Updater April 2012.

1 market efficiency, financial market development, technological readiness, market
2 size, business sophistication, and innovation.⁴⁴ According to the 2012-2013 report,
3 Canada is ranked 14th and the U.S. is ranked 7th in competitiveness and productivity.⁴⁵
4 The WEF report describes the Global Competitiveness Index as “a comprehensive
5 tool that measures the microeconomic and macroeconomic foundations of national
6 competitiveness.”⁴⁶ The report further explains:

7 We define competitiveness as the set of institutions, policies, and
8 factors that determine the level of productivity of a country. The
9 level of productivity, in turn, sets the level of prosperity that can be
10 earned by an economy. The productivity level also determines the
11 rates of return obtained by investments in an economy, which in turn
12 are the fundamental drivers of its growth rates.⁴⁷

13 **Q. Are you aware of any reports that comment on the relative strength of the**
14 **Canadian and U.S. economies?**

15 **A.** Yes. In an October 2012 report, S&P commented:

16 Standard and Poor’s base case outlook is for subdued growth in
17 Canada, with real GDP advancing 2.1% in 2012 and 1.9% in 2013.
18 Our forecast assumes the fragile position of the global recovery,
19 impairment in international trade, and the high value of the Canadian
20 dollar will continue to dampen business for Canadian exporters. The
21 economic headwinds buffeting Canadian exports stem primarily from
22 the loss of economic momentum in the U.S. and recessionary
23 conditions in Europe, Canada’s two main export markets and the
24 destination for more than 80% of Canada’s exports. We don’t expect
25 Europe to emerge from recession until later in 2013, while for the

⁴⁴ “The Global Competitiveness Report: 2012-2013”, World Economic Forum, Centre for Global Competitiveness and Performance, at pp. 4-7.

⁴⁵ Ibid., Table 3, at p. 13.

⁴⁶ Ibid., at p. 4.

⁴⁷ Ibid.

1 U.S. we see subpar GDP growth of about 2% continuing through the
2 end of 2013.⁴⁸

3 From the current vantage point it appears that downside risk to
4 Canada's economy will continue to outweigh upside potential
5 through 2013. We expect the weakened global economy and
6 impairment in international trade to limit growth. Domestic
7 spending is unlikely to be a major source of growth as consumers
8 appear to be focusing more on repairing their balance sheets and less
9 willing to spend. Against this backdrop, we expect nonfinancial
10 companies to remain focused on conserving capital, tempering their
11 investment plans. We see this spilling over into reduced hiring
12 activity and weakening demand for labor, which could put downward
13 pressure on unemployment through the first half of 2013. We think
14 this means income growth will remain subdued so it appears the
15 stage is set for a moderation in housing demand.⁴⁹

16 Further, a February 2013 report from the International Monetary Fund on the
17 Canadian economy states:

18 Growth [in Canada] is expected to gain new momentum over 2013.
19 We expect economic activity to grow at a pace slightly above
20 potential (estimated at about 2 percent) from the second half of the
21 year, thanks to the strengthening of the U.S. economy from mid-2013
22 The United States is Canada's largest trading partner, absorbing
23 about two thirds of total Canadian merchandise exports, and with
24 significant financial linkages to Canada. Tighter financial conditions
25 in the United States tend to lead to tighter financial conditions in
26 Canada. When the impact of the U.S. financial shock is decomposed
27 into trade and financial channels, the latter channel appears to be
28 larger.⁵⁰

29 Finally, according to Consensus Economics, the forecast for economic growth in
30 Canada and the U.S. is very similar, with both countries expected to experience real
31 GDP growth between 2.0 and 2.5 percent in the period from 2018-2022.⁵¹

⁴⁸ "Economic Research: A Weakened Global Economy Threatens Canada's Growth Momentum," Standard & Poor's Ratings Direct, October 3, 2012, at 2.

⁴⁹ Ibid., at pp. 7-8.

⁵⁰ International Monetary Fund, Country Report No. 13/40, February 2013, at pp. 7, 8, 35, and 36.

⁵¹ Consensus Forecasts, for 2018-2022, October 8, 2012, at pp. 3 and 28.

1 **Q. Have you compared the overall economic and investment environment in**
2 **Canada and the U.S.?**

3 A. Yes. Exhibit JMC-2 presents several measures that reflect the overall economic and
4 investment environment in Canada and the U.S. The first measure compares the
5 returns to investors from the TSX 300 and S&P 500 stock indices. From 1988
6 through 2012, the total return on the TSX 300 was 9.66 percent compared to 11.34
7 percent for the S&P 500. Over the past five years, the total return on the TSX has
8 been 3.63 percent compared to 4.52 percent for the S&P 500. Turning to the Utility
9 Stock Index, average total returns for Canadian and U.S. utility investors have been
10 very similar between 2003 and 2012 (i.e., 11.89 percent in Canada vs. 11.66 percent
11 in the U.S.).⁵²

12 As also shown on Exhibit JMC-2, the correlation between real GDP growth rates in
13 the two countries is strong, as is the correlation between the consumer price indices
14 for each country, indicating that these metrics tend to move together over time
15 between the two countries. Over the 25-year period, real GDP growth has been 2.40
16 percent in Canada and 2.54 percent in the U.S., while consumer inflation has been
17 2.33 percent in Canada and 2.86 percent in the U.S. The average unemployment rate
18 over the 25 year period has been substantially higher in Canada (i.e., 7.4 percent in
19 Canada vs. 6.0 percent in the U.S.), but that trend has reversed since 2008 as the U.S.
20 has been slower to recover from the recent recession.

21 **Q. Have you also compared bond yields between Canada and the U.S.?**

⁵² Source: Bloomberg Professional Service. Return includes both price appreciation and dividend yield. Dividend data for the S&P/TSX Utilities Index were not available prior to 2003.

1 A. Yes. The average yields on 10-year government bonds have also been very similar in
2 Canada and the U.S. over the past decade. Specifically, the 10-year average yield on
3 10-year Canadian government bonds has been 3.67 percent, while the average yield
4 on 10-year U.S. Treasury bonds has been 3.66 percent. During 2012, the average
5 yield on 10-year government bonds was 1.85 percent in Canada and 1.80 percent in
6 the U.S. The correlation between average annual interest rates on 10-year
7 government bonds in Canada and the U.S. since 1988 has been 0.98, the highest of
8 all macroeconomic indicators compared; similarly, the correlation between daily
9 average interest rates on 10-year government bonds in Canada and U.S. from 2008
10 through 2012 was 1.00, as central banks in both countries responded to the credit
11 crisis and financial market dislocation by providing supportive monetary policy.
12 Correlations of this degree are reflective of closely integrated financial markets.

13 **Q. What other evidence did Concentric consider to assess the extent to which the**
14 **Canadian and U.S. economies are integrated?**

15 A. First, the magnitude and significance of trade between the two countries also
16 indicates the high degree of integration between the two markets. In 2012, in terms
17 of trade in goods, 73.7 percent of Canada's total exports went to the U.S., and
18 imports from the U.S. accounted for 49.5 percent of Canada's total imports.⁵³
19 Moreover, according to a report by the Congressional Research Service ("CRS"),
20 Canada is the largest single-nation trading partner of the United States. The CRS
21 observes:

⁵³ Trade Data Online – Canadian Trade by Industry, Industry Canada.

1 That the United States and Canada trade substantial volumes of the
2 same goods bespeaks the economic integration of the two
3 economies. This integration has been assisted by trade liberalization
4 over the past 40 years, beginning with the Automotive Agreement of
5 1965 (which eliminated tariffs on shipments of autos and auto parts
6 between the two countries), through the Canada-U.S. Free Trade
7 Agreement of 1989, and NAFTA [the North American Free Trade
8 Agreement of 1994].⁵⁴

9 Furthermore, the CRS report comments on the amount of foreign investment
10 between Canada and the U.S. as follows:

11 The U.S.-Canada economic relationship is characterized by
12 substantial ownership interests in each nation by investors in the
13 other. The United States is the largest single investor in Canada, with
14 a stock of \$296.7 billion in 2010, a figure representing 7.6% of U.S.
15 direct investment abroad (DIA). U.S. investors accounted for 54.4%
16 of the stock of foreign direct investment (FDI) in Canada in 2010,
17 down from 64.1% in 2004... Canada had a prominent (though not
18 the largest) FDI position in the United States at \$206.1 billion, 8.8%
19 of the total FDI stock in the United States in 2010, and the United
20 States is the most prominent destination for Canadian DIA, with a
21 stock of 40.5% of total Canadian DIA that year.⁵⁵

22 The high degree of integration between the Canadian and U.S. markets is also
23 evident in data regarding trade between the U.S. and Québec. According to the
24 Province of Québec, the U.S. accounts for more than 60 percent of foreign
25 investment in Québec.⁵⁶ Moreover, in 2011, trade with the U.S. accounted for 68
26 percent of Québec's exports and 30 percent of Québec's imports.⁵⁷

27 **Q. What has been the exchange rate between Canada and the U.S.?**

⁵⁴ Ian F. Fergusson, "United States – Canada Trade and Economic Relationship: Prospects and Challenges," Congressional Research Service, September 14, 2011, at p. 3.

⁵⁵ Ibid., at p. 10.

⁵⁶ See <http://www.gouv.qc.ca/portail/quebec/international/usa/quebec/quebec-etats-unis/>.

⁵⁷ Institut de la statistique du Québec.

1 A. The value of the Canadian dollar has fluctuated against the U.S. dollar (as with all
2 currencies) over the past 25 years. The Canadian dollar fell to \$1.57 per U.S. dollar
3 in 2002 before rebounding to \$0.99 in 2011; it stood at \$1.03 as of March 4, 2013.
4 Consensus Forecasts reports that exchange rates between the Canadian and U.S.
5 dollar are expected to remain relatively stable through at least February 2015.⁵⁸

6 **Q. What are your conclusions regarding the economic and business**
7 **environments of Canada and the U.S. and their effect on investment risk?**

8 A. On balance, the economic and business environments of Canada and the U.S. are
9 highly integrated and exhibit strong correlation across a variety of metrics, including
10 GDP growth and historical government bond yields. From a business risk
11 perspective, including overall business environment and competitiveness, Canada
12 and the U.S. are ranked closely when compared against other developed and
13 developing countries. Based on these macroeconomic indicators, there are no
14 fundamental dissimilarities between Canada and the U.S. (*i.e.*, in terms of economic
15 growth, inflation rates, unemployment rates, or government bond yields) that would
16 cause a reasonable investor to have different return expectations for the two
17 countries.

18 **VII. RISK ANALYSIS**

19 **Q. What is the purpose of Concentric's risk analysis?**

20 A. Concentric's risk analysis has two purposes. First, the risk analysis examines whether
21 it is reasonable and appropriate to use Canadian and U.S. proxy groups to establish

⁵⁸ Consensus Forecasts, Consensus Economics, Inc., February 11, 2013, at p. 27.

1 the allowed ROE for HQD and HQT. Second, the risk analysis evaluates whether
2 any adjustments should be made to the results for the Canadian and U.S. proxy
3 groups to account for differences in business and financial risk between those proxy
4 groups and HQD and HQT.

5 In order to evaluate the comparability of the Canadian and U.S. proxy groups,
6 Concentric has examined the business and financial risks of each operating company
7 relative to those of HQD and HQT. The purpose of this evaluation is to determine
8 the extent to which the companies in the Canadian and U.S. proxy groups operate in
9 regulatory environments which provide similar risk protection as HQD and HQT
10 receive in Québec. In addition, Concentric has reviewed the allowed ROEs for a
11 group of government-owned electric utilities in Canada to provide additional
12 context.

13 **Q. Has Concentric examined the ownership, operations and financing of each of**
14 **the companies in the Canadian and U.S. proxy groups?**

15 A. Yes. Exhibit JMC-3, Schedule 1, provides a summary of several relevant indicators
16 for the companies in the Canadian and U.S. proxy groups, including: (1) the S&P
17 credit rating for the parent company; (2) the Beta coefficient reported by Bloomberg
18 for the parent company as of February 28, 2013; (3) the most recent authorized ROE
19 for the operating company; and (4) the most recent deemed equity ratio for the
20 operating company.

21 Exhibit JMC-3, Schedule 2, presents a summary of several operating statistics for the
22 operating companies in the Canadian and U.S. proxy groups, including: (1) the

1 province or state in which the utility provides service; (2) the 2011 regulated electric
2 revenues; (3) the percentage of sales to industrial customers; and (4) the number of
3 retail distribution customers served. As shown on Exhibit JMC-3, Schedule 2,
4 HQD's regulated electric revenues are higher than the other distribution companies
5 in the Canadian and U.S. proxy groups with the exception of Florida Power and
6 Light, which is comparable; HQT's regulated revenues are approximately ten times
7 higher than the only other electric transmission company in the Canadian proxy
8 group (i.e., ATCO Electric Transmission). HQD has more retail distribution
9 customers than any other distribution company in the Canadian and U.S. proxy
10 groups with the exception of Florida Power and Light; and HQD is more dependent
11 on sales to industrial customers than any of the companies in the Canadian or U.S.
12 proxy groups, except ATCO Electric Distribution.

13 **A. Business Risk**

14 **Q. Please define business risk.**

15 A. Business risk represents changes in revenues and costs that may result in variability in
16 cash flows and earnings and the ability of the utility to recover its costs including the
17 fair return on, and of, its capital in a timely manner.

18 **Q. Please describe your business risk analysis.**

19 A. For purposes of this testimony, Concentric has focused on eight primary business
20 risks for electric utilities. Since certain of these risk factors are more relevant for
21 transmission companies, while others are more applicable to distribution companies,

1 the discussion accompanying each risk factor explains the relevance of that factor for
2 HQD and HQT. The risk factors include:

- 3 (1) Ownership of regulated generation;
- 4 (2) Fuel and purchased power cost risk;
- 5 (3) Volume/demand risk;
- 6 (4) Capital cost recovery risk;
- 7 (5) Rate regulation and earnings sharing;
- 8 (6) Regulatory lag;
- 9 (7) Cost recovery mechanisms; and
- 10 (8) Longer-term risks.

11 The detailed results of the business risk analysis are presented in Appendix A and in
12 Exhibit JMC-4, Schedules 1-7.

13 **Q. Please summarize the overall conclusions with respect to the business risk of**
14 **HQD and HQT relative to the Canadian and U.S. proxy groups.**

15 A. As a preliminary matter, Concentric notes that regulatory protection is generally
16 more effective at reducing short-term business risk, but may not fully mitigate
17 longer-term business risk. The following briefly summarizes the conclusions with
18 regard to the major categories of business risk for HQD and HQT relative to the
19 Canadian and U.S. proxy groups:

- 20 (1) Regulated generation risk: HQD owns very limited regulated generation
21 (diesel generation in remote communities) and has similar business risk as the
22 operating companies in the Canadian proxy group, the majority of which do

1 not own regulated generation. HQD has lower business risk than the U.S.
2 proxy group operating companies, several of which own significant regulated
3 generation. HQT is a pure-play transmission company and does not own
4 regulated generation.

5 (2) Fuel and purchased power cost risk: HQD obtains approximately 97 percent
6 of its energy supply from the Heritage Pool and has no risk associated with
7 changes in the price of that supply. HQD purchases the remaining three
8 percent of its energy supply under long-term contracts and does not have an
9 automatic adjustment mechanism for purchased power costs. Rather, those
10 costs are recovered through the annual rate case filing, and any difference
11 between actual and forecasted purchased power costs is deferred and
12 recovered through a cost variance account. The distribution companies in
13 the Canadian and U.S. proxy groups have fuel adjustment clauses that allow
14 them to pass through fuel costs to customers. As such, those companies are
15 generally not at risk for differences between the projected and actual cost of
16 fuel, with limited exceptions in Wisconsin and Nova Scotia.

17 (3) Volume/demand risk: HQD has somewhat less protection against changes in
18 volume/demand than the operating companies in the Canadian proxy group,
19 the majority of which have broader protection against volume risk through
20 revenue decoupling or Lost Revenue Adjustment Mechanisms (“LRAM”)
21 than HQD, which only has protection against volumetric risk through its
22 weather variance account. HQD has similar protection against volume risk

1 as the operating companies in the U.S. electric utility proxy group, some of
2 which have revenue decoupling mechanisms or operate under formula rate
3 plans that protect against volumetric risk and some of which have weather
4 normalization clauses. HQT is not exposed to risks associated with changes
5 in demand. Similarly, other Canadian and U.S. transmission operations have
6 little risk with respect to fluctuations in volume/demand due to the way in
7 which costs are trued-up and recovered.

8 (4) Capital cost recovery risk: HQD and HQT generally have comparable risk
9 mitigation for capital cost recovery as the operating companies in the
10 Canadian proxy group because regulated utilities in Canada generally file rate
11 cases on a more frequent basis, and are able to include capital investments in
12 rate base once they are placed into service and start earning a return on those
13 investments without significant regulatory lag. Although most of the
14 operating companies in the U.S. electric utility proxy group do not file rate
15 cases as frequently as those in Canada, the companies have comparable risk
16 protection on this factor as HQD and HQT because many U.S. regulators
17 have approved a cash return on CWIP while the plant is under construction,
18 or have approved implementation of cost tracking mechanisms that provide
19 accelerated recovery of capital costs for replacing aging infrastructure.

20 (5) Rate regulation and earnings sharing: HQD and HQT have historically
21 operated under traditional cost-of-service regulation, while more than 70
22 percent of operating companies in the Canadian proxy group are under

1 incentive regulation mechanisms (“IRM”) or are in the process of renewing
2 those plans. Most, but not all, of those incentive plans include an earnings
3 sharing mechanism (“ESM”). Among the U.S. electric utility proxy group,
4 slightly more than half of the operating companies are subject to an IRM
5 within the context of a multi-year rate plan or formula rate plan, and all of
6 those plans include a mechanism for sharing earnings with customers. If
7 HQD and HQT were to begin operating under an ESM, as they have
8 proposed as part of this filing, their business risk would become more similar
9 to the majority of operating companies in the Canadian and U.S. proxy
10 groups, depending on the design and parameters of the specific ESM that is
11 approved by the Régie. A reasonably balanced ESM should not materially
12 impact the level of risk faced by HQD and HQT.

13 (6) Regulatory lag: HQD and HQT have similar regulatory treatment with
14 respect to the use of forecasted test years as the operating companies in the
15 Canadian proxy group and slightly less risk than the companies in the U.S.
16 electric utility proxy group, which are somewhat less likely to use forecasted
17 test years. With regard to interim rates, HQD has somewhat higher risk than
18 the operating companies in the Canadian proxy group and higher risk than
19 the operating companies in the U.S. proxy group, the vast majority of which
20 have the ability to request interim rate increases while a rate case is pending.
21 HQT can implement interim rates, and therefore has somewhat lower risk
22 than the operating companies in the Canadian proxy group and similar risk to
23 the operating companies in the U.S. proxy group on this factor.

1 (7) Cost recovery mechanisms: On balance, HQD and HQT have similar
2 regulatory protection to the companies in the Canadian and U.S. proxy
3 groups against specific categories of costs that tend to fluctuate significantly
4 from year to year, are material in nature, and are beyond the control of utility
5 management. Notable exceptions are that HQD has limited protection for
6 operating costs but not capital costs related to storms, and HQT does not
7 have a storm cost recovery mechanism, while that protection is widely
8 available to the companies in the U.S. electric utility proxy group, and HQD
9 and HQT have variance accounts for pension expense, while more than half
10 of the companies in the U.S. electric utility proxy group do not have
11 protection against this risk.

12 (8) Longer-term risks: HQD faces higher competitive risk than the operating
13 companies in the Canadian and U.S. proxy groups due to its concentration of
14 industrial customers. HQD also faces higher business risk than when the
15 Régie issued its previous ROE determination due to changes in the relative
16 competitiveness of electricity and natural gas prices in Québec, especially
17 given the importance of electricity for heating purposes among residential
18 and commercial customers. HQT faces higher business and financial risk
19 due to its capital expenditure requirements over the next decade for growth
20 response and to replace aging transmission infrastructure as compared with
21 the amount of capital spent over the previous decade.

1 Based on the business risk analysis, Concentric concludes that HQD and HQT and
2 the operating companies in the Canadian proxy group generally receive comparable
3 protection against the business risks which are important to investors and credit
4 rating agencies. There are several important ways, however, in which HQD's and
5 HQT's longer-term business risk is higher than the Canadian proxy group.
6 Specifically, HQD faces more competitive risk due to its higher concentration of
7 industrial customers, which suggests that HQD is more susceptible to risks
8 associated with economic bypass and demand destruction, as well as more vulnerable
9 to weak economic conditions. Further, HQD faces higher business risk than at the
10 time of its previous ROE determination because natural gas prices have become
11 more competitive with electricity prices in Québec. In addition, HQT faces greater
12 business and financial risk associated with its capital expenditure requirements over
13 the next decade for growth response and to replace aging transmission infrastructure.

14 With regard to the operating companies in the U.S. electric utility proxy group, on
15 balance, the one distinguishable difference in business risk between HQD and the
16 U.S. proxy group is the higher percentage of U.S. companies that own regulated
17 generation. As discussed in the subsequent section on financial risk, however,
18 Concentric finds that the higher business risk associated with regulated generation is
19 more than offset by the lower financial risk (i.e., higher equity ratios) of the operating
20 companies in the U.S. proxy group relative to HQD. With regard to HQT, although
21 none of the comparators are pure transmission companies, Concentric concludes
22 that there are no fundamental differences in business risk between HQT and the
23 U.S. electric utility proxy group that would render comparisons inappropriate. As

1 discussed above, HQD and HQT have similar business risk as the U.S. electric utility
2 proxy group on most factors that affect the short and intermediate term variability of
3 earnings and cash flows. Notable differences are the approval of CWIP in rate base
4 for companies in the U.S. proxy group, the use of forecasted test years for HQD and
5 HQT, and the prevalence of storm cost trackers for the U.S. proxy group. In
6 summary, there are no significant differences in business risk between HQD and
7 HQT and the operating companies in the U.S. electric utility proxy group, other than
8 the ownership of regulated generation by the U.S. electric utilities, which is more
9 than offset by higher equity ratios in the U.S.

10 From the perspective of establishing the allowed ROE for HQD and HQT,
11 Concentric concludes that the U.S. proxy group (at the holding company level) is
12 more comparable to HQD and HQT than the Canadian proxy group because it is
13 comprised of companies that derive the majority of their operating income and
14 revenues from electric utility service. Moreover, there are very few potential proxy
15 companies in Canada, which limits the ability to select companies that are
16 comparable to the electric distribution and transmission operations of HQD and
17 HQT. For that reason, Concentric believes it is reasonable and appropriate to rely
18 primarily on the results of the U.S. electric utility proxy group and to use the
19 Canadian proxy group to corroborate the reasonableness of the U.S. results.

1 **B. Financial Risk**

2 **Q. Please define financial risk.**

3 A. Financial risk exists to the extent a company incurs fixed obligations in financing its
4 operations. These fixed obligations increase the level of income which must be
5 generated to cover interest payments before common stockholders receive any
6 return, and they are considered by equity investors in addition to business and
7 regulatory risks. Fixed financial obligations also reduce a company's financial
8 flexibility and its ability to respond to adverse economic circumstances and capital
9 market conditions, such as those during the credit crisis and financial market
10 dislocation of 2008 and 2009. The detailed results of the financial risk analysis are
11 discussed in Appendix B and on Exhibit JMC-5.

12 **Q. What is your conclusion with respect to the financial risk of HQD and HQT**
13 **relative to the Canadian and U.S. proxy group companies?**

14 A. Based on the lower equity ratios and the weaker credit metrics of HQD and HQT,
15 Concentric concludes that these companies have greater financial risk than either the
16 Canadian proxy group or the U.S. electric utility proxy group. Specifically, the actual
17 credit metrics for HQD and HQT (as shown on Exhibit JMC-5) are not consistent
18 with Hydro-Québec's current S&P rating of A+. Assuming that the Régie approves
19 an ESM for HQD and HQT, the Companies will be required to share some
20 percentage of any over-earnings with customers. As discussed in Section II of the
21 testimony, the credit rating agencies have expressed concern with the low authorized
22 ROEs and deemed equity ratios for HQD and HQT. Recognizing that HQD's and

1 HQT's credit metrics have been supported by surplus earnings over the allowed
2 ROE in the past several years, the implementation of an ESM must be designed with
3 care. The ESM must be balanced with an appropriate ROE in order to avoid any
4 diminution in credit quality that would affect the cost of the HQD and HQT
5 government debt guarantee, or limit the ability of Hydro-Québec to continue paying
6 comparable cash dividends to its shareholder.

7 **Q. Did Concentric evaluate the effect of HQD's and HQT's deemed equity**
8 **ratios on the appropriate cost of equity for those companies?**

9 A. Yes. HQD and HQT are proposing to maintain their current deemed equity ratios
10 of 35.0 percent and 30.0 percent, respectively. As discussed in Appendix B, the
11 equity ratios for HQD and HQT are somewhat lower than the deemed equity ratios
12 for the operating divisions of the Canadian proxy group, and are substantially lower
13 than the authorized equity ratios of the U.S. electric utility proxy group. In order for
14 HQD and HQT to have the opportunity to earn weighted compensatory equity
15 return at their respective equity ratios as the U.S. electric utility proxy group at an
16 average equity ratio of 50.2 percent, significant increases in the authorized ROE
17 would be required to compensate for the difference in authorized capital
18 structure. Using commonly-accepted methodologies, Concentric estimates that an
19 adjustment to ROE of between approximately 1.50 percent and 3.00 percent would
20 be warranted to compensate for a 15 to 20 percent decline in the common equity
21 ratio from the U.S. proxy group average. These estimates are consistent with the
22 range reported by empirical and theoretical studies for public utilities. Those studies

1 show increases in the required ROE from 0.34 to 2.37 percentage points to
2 compensate for a 10 percent increase in the debt ratio.⁵⁹

3 **Q. How does this adjustment for the difference in equity ratios between HQD**
4 **and HQT and the U.S. proxy group compare to the effect on the cost of**
5 **equity related to the U.S. proxy group companies' ownership of regulated**
6 **generation?**

7 A. As discussed in the following section of this testimony, the incremental ROE
8 required to offset the increased operating risk of regulated generation is
9 approximately 41 basis points. Although Concentric does not propose an
10 adjustment in this proceeding for the difference in capital structure between HQD
11 and HQT and the U.S. electric utility proxy group, Concentric views the financial
12 risk of a more highly-leveraged capital structure as more than offsetting any potential
13 difference in the required ROE of the U.S. electric utility proxy group companies
14 that own regulated generation.

15

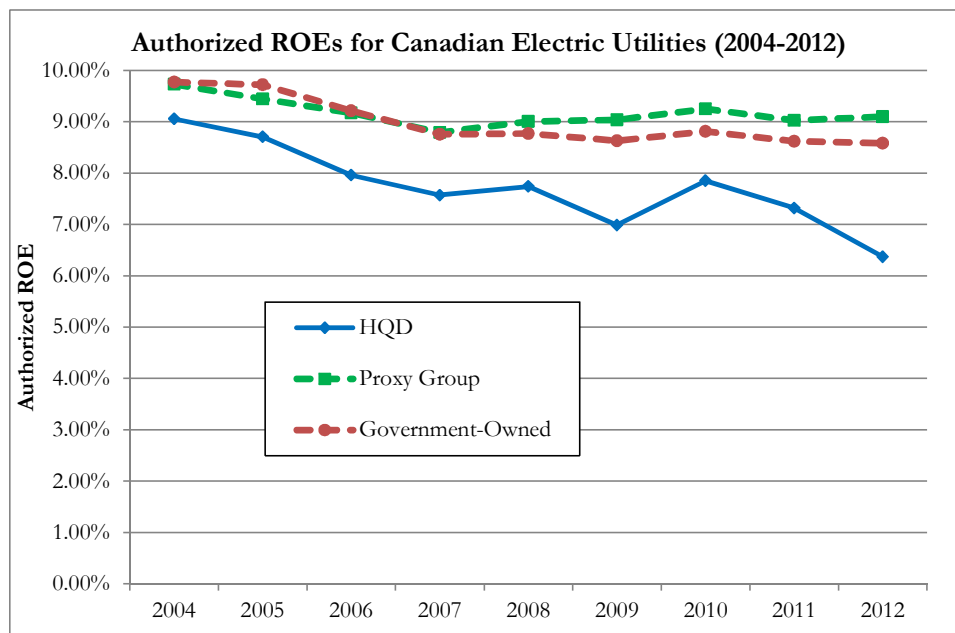
⁵⁹ See, *New Regulatory Finance*, Dr. Roger Morin, Public Utility Reports, 2006, pp. 456 - 471

1 **VIII. ANALYSIS OF EARNED AND AUTHORIZED RETURNS**

2 **Q. Have you analyzed the authorized returns for HQD and HQT relative to the**
3 **Canadian and U.S. proxy group companies?**

4 A. Yes. As shown on Charts 1 and 2, the authorized ROEs for HQD and HDT from
5 2004-2012 have been lower than the Canadian investor-owned electric utilities
6 (“IOU”) and Canadian government-owned electric utilities (“GOU”), and this
7 margin has grown over the past two years. Among the possible explanations for the
8 increasing disparity between the authorized ROEs for HQD and HQT and other
9 Canadian IOUs and GOUs are: (1) a more favorable automatic adjustment formula
10 for the other IOUs and GOUs in Canada, and (2) a higher risk premium for the
11 other Canadian IOUs and GOUs as a result of a different adjustment adder.

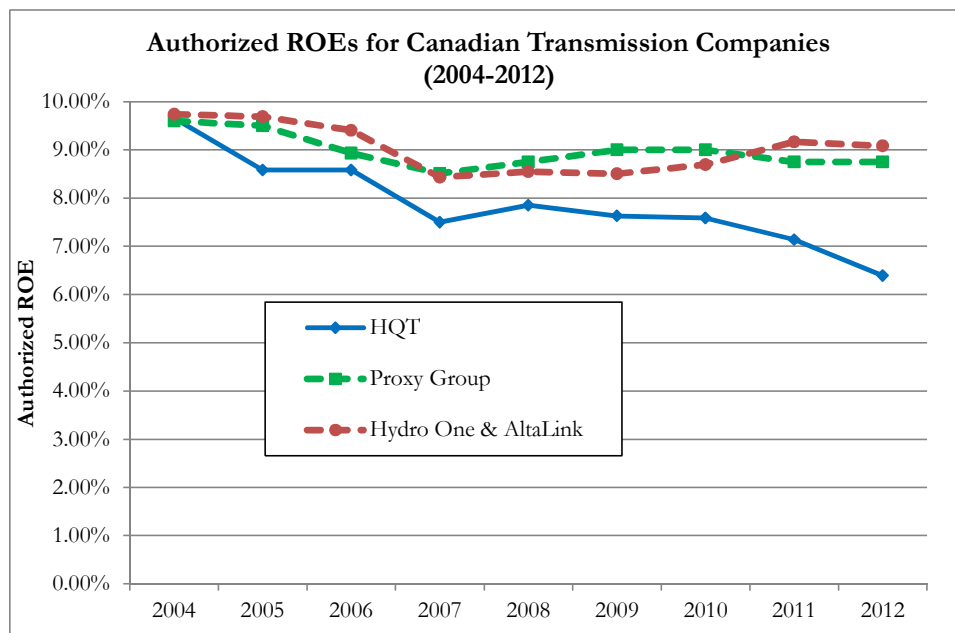
1 **Chart 1: Authorized ROE for Canadian Electric Distribution Utilities⁶⁰**



2

⁶⁰ The Proxy Group average includes ATCO Electric (Distribution), FortisAlberta, FortisBC Electric, Newfoundland Power, and Nova Scotia Power Inc. The government-owned average includes Hydro One Inc. (Distribution), SaskPower, ENMAX Power, and EPCOR Distribution. Manitoba Hydro is not included among the government-owned utilities because its rates are set based on a targeted debt-to-equity ratio rather than an authorized return on common equity. BC Hydro is not included because its authorized return on equity of 14.37 percent includes an adjustment for income taxes based on the tax rate of the benchmark utility in British Columbia (i.e., 9.50% X 1.342 = 12.75%) plus an adder of 1.63 percent.

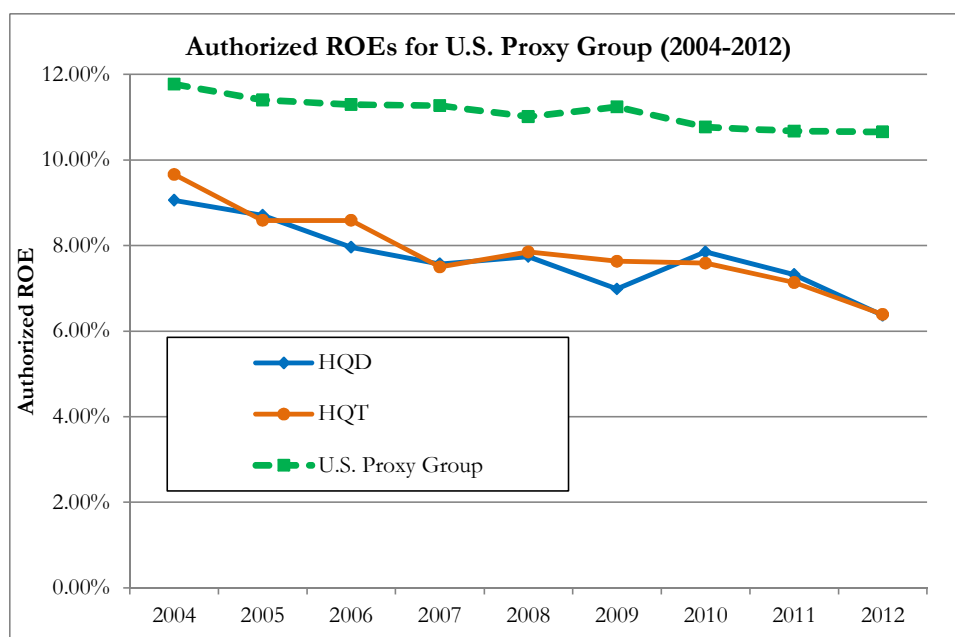
Chart 2: Authorized ROE for Canadian Electric Transmission Utilities⁶¹



Similarly, as shown on Chart 3, the authorized ROEs for HQD and HQT from 2004-2012 have been lower than the operating companies in the U.S. electric utility proxy group, and that margin has widened over the past several years.

⁶¹ The Proxy Group line represents ATCO Electric (Transmission), and the other line shows the average of AltaLink and Hydro One Inc. (Transmission).

**Chart 3: Authorized ROE for U.S. Electric Utility Proxy Group
(Compared to HQD and HQT)**



Concentric also compared the allowed ROEs for HQD and HQT to the authorized return for integrated electric utilities and T&D utilities in the U.S. While this survey contains a broader group of electric utility companies than the U.S. proxy group, it does provide useful information regarding the aggregate level of returns that has been approved for electric utilities in the U.S. as compared to those in Canada generally and for HQD and HQT in particular. According to Regulatory Research Associates, the average authorized ROE for vertically-integrated electric utilities in the U.S. between 2004 and 2012 was 10.46 percent, and the average authorized ROE for transmission and distribution (“T&D”) only utilities in the U.S. was 10.05 percent.⁶² Furthermore, the average authorized equity ratio for vertically-integrated

⁶² Source: SNL Financial.

1 electric utilities and T&D only utilities in the U.S. over this same time period was
2 very similar (i.e., 48.90 percent for integrated and 47.61 percent for T&D).⁶³

3 Compared to the computed average authorized ROE, HQD's average allowed ROE
4 of 7.73 percent from 2004-2012 was 273 basis points lower than the average
5 integrated U.S. electric utility and 232 basis points lower than the average U.S. T&D
6 company. Similarly, HQT's average allowed ROE of 7.88 percent from 2004-2012
7 was 258 basis points lower than the average U.S. electric utility company and 217
8 basis points lower than the average U.S. T&D company. In summary, HQD's and
9 HQT's allowed ROEs over this period have been substantially below those granted
10 to the average integrated electric utilities and T&D companies in the U.S.

11 **Q. Did Concentric also compare the earned and allowed returns for the U.S.**
12 **electric utility proxy group?**

13 A. Yes. As discussed earlier in our testimony, the Régie has stated in prior decisions
14 that earned ROEs are an important indicator of whether the operating utility has
15 sufficient regulatory protection against various business risks. While this comparison
16 is useful in evaluating the short-term risk protection of operating companies in the
17 proxy group, it is less helpful in terms of assessing the longer-term risks of those
18 entities, especially with respect to recovery of their investment in rate base.

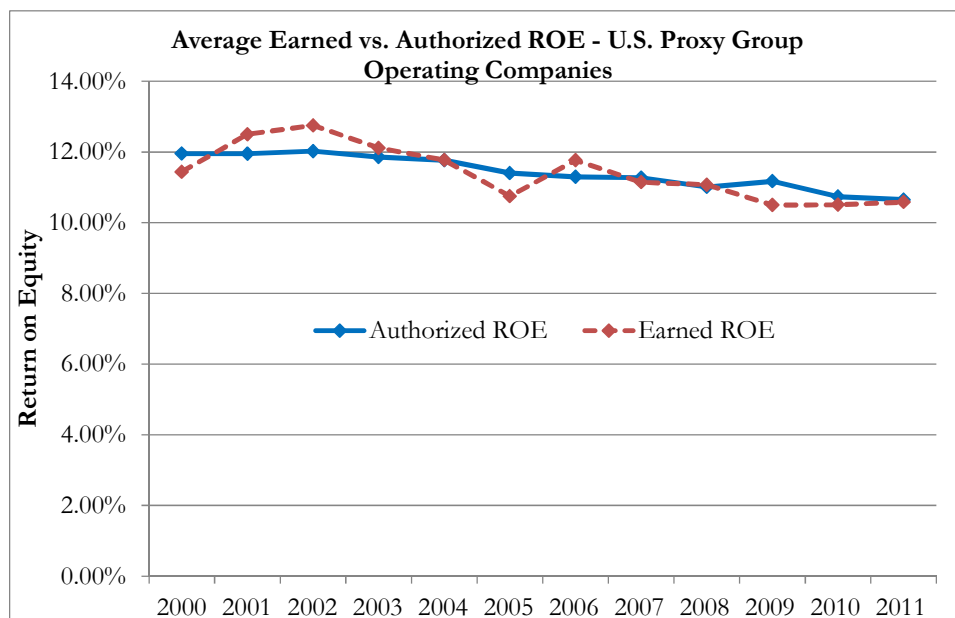
19 **Q. Please summarize the results of that analysis.**

20 A. As shown on Chart 4, Concentric has compared the earned and authorized ROEs
21 for the companies in the U.S. electric utility proxy group at the operating company

⁶³ Ibid.

1 level from 2000-2011. The average earned ROE for the U.S. electric utility proxy
2 group (at the operating company level) from 2000-2011 was almost identical to the
3 average authorized ROE over that same period (i.e., 11.41 percent earned vs. 11.42
4 percent authorized).

5 **Chart 4: Average Earned vs. Authorized ROE – U.S. Proxy Group – 2000-2011**



6
7 **Q. What is your conclusion with regard to the use of U.S. data based on your**
8 **analysis of earned and allowed returns for the U.S. electric utility proxy**
9 **group?**

10 A. Concentric’s analysis demonstrates that the operating companies in the U.S. electric
11 utility proxy group for which data are available⁶⁴ have generally been able to earn
12 their authorized returns from 2000-2011. This suggests that these companies

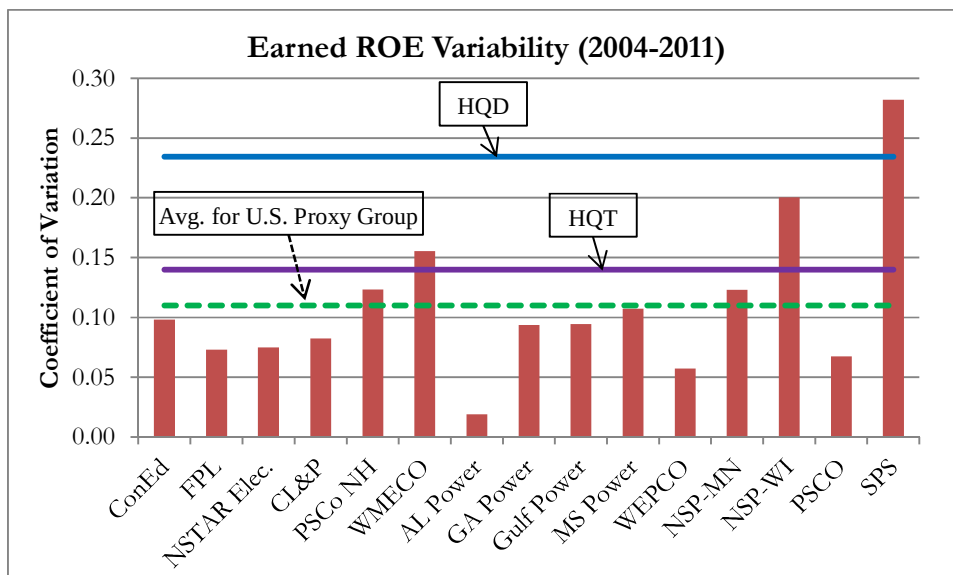
⁶⁴ There are certain years in which the authorized ROE was not specified in the settlement agreement that was approved by the Commission. In those instances, Concentric excluded the earned return from the calculation of the average. Companies affected include Southwestern Public Service in Texas, NSTAR Electric and Western Massachusetts Electric, Public Service of New Hampshire, and Wisconsin Electric Power.

1 generally operate in regulatory environments that afford timely cost recovery and a
2 fair opportunity to earn their allowed returns. As such, Concentric concludes that it
3 is reasonable and appropriate to consider the U.S. electric utility proxy group as an
4 appropriate benchmark for the market-based cost of equity for HQD and HQT.

5 **Q. Did Concentric also analyze the variability of earned returns for HQD and**
6 **HQT to the U.S. proxy group?**

7 A. Yes. In order to evaluate the variability of earned returns for HQD and HQT
8 compared to the U.S. electric utility proxy group, Concentric compared the
9 coefficient of variation (“CV”) for the earned returns of HQD and HQT from 2004-
10 2011 to the CV for each of the operating companies in the U.S. electric utility proxy
11 group. The CV is a statistical measure that shows the extent of variability, as
12 measured by the standard deviation, in relation to the mean. Specifically, the CV is
13 calculated as a ratio or percentage by dividing the standard deviation by the mean.
14 As shown on Chart 5, the earned ROEs for HQD and HQT have been more
15 variable than the average for the U.S. electric utility proxy group from 2004-2011.

Chart 5: Coefficient of Variation – Earned ROE – U.S. Proxy Group⁶⁵



Based on this analysis, it is not correct to assume that earnings are more variable for the companies in the U.S. electric utility proxy group than for HQD and HQT. As such, Concentric finds that it is reasonable and appropriate to consider the U.S. electric utility proxy group as a reliable benchmark for the market-based cost of equity for HQD and HQT.

E. Risk Analysis Conclusions

Q. Please summarize your conclusions and recommendations on the comparability of HQD and HQT and the Canadian and U.S. proxy groups.

A. Based on the results of the risk analysis described in our testimony, Concentric recommends that the Régie find that:

⁶⁵ The calculations in Chart 5 are based on historical data, and may not represent the future variability in earnings due to the addition/deletion of variance accounts or revenue stabilization mechanisms.

- 1 • The economic conditions and business environments in Canada and the U.S.
2 are similar enough that investors would not require materially different
3 returns on equity from companies that were otherwise comparable;
- 4 • The regulatory protections to mitigate business risk for HQD and HQT are
5 similar to those for the operating companies in the Canadian and U.S. proxy
6 groups, except that the U.S. electric utilities have more risk associated with
7 the ownership of regulated generation;
- 8 • The financial risk of HQD and HQT is somewhat higher than the Canadian
9 proxy group and substantially higher than the U.S. electric utility proxy
10 group, as evidenced by lower deemed equity ratios and weaker credit
11 metrics. This risk more than offsets the higher business risk of the U.S.
12 electric utility proxy group due to ownership of regulated generation;
- 13 • The earned returns of the U.S. electric utility proxy group at the operating
14 company level have been very similar to the allowed returns for those
15 companies, suggesting that those companies generally have adequate
16 regulatory protection in place to recover costs in a timely manner, which
17 generally allows them to earn their authorized ROE in most years;
- 18 • The current authorized ROEs for HQD and HQT do not meet the
19 comparable return standard⁶⁶ for a stand-alone electric transmission and
20 distribution utility⁶⁷, as shown by comparison to authorized returns for the

⁶⁶ See Section III of this testimony for a discussion of the Fair Return Standard.

⁶⁷ As noted previously, the Régie has determined that the allowed ROE must be comparable to that which the market would require for a stand-alone electric distribution or transmission company.

1 Canadian and U.S. proxy groups, as well as the other government-owned
2 electric utilities in Canada;

- 3 • It is reasonable to use the U.S. electric utility proxy group to estimate the
4 cost of equity for HQD and HQT in this proceeding with the Canadian
5 proxy group used to corroborate the reasonableness of the U.S. results is
6 reasonable; and
- 7 • HQD and HQT have similar but not identical risk profiles. On balance,
8 HQD carries greater risk than HQT. Differentiating risk factors include
9 HQD's competition from alternative fuels, HQD's supply risk and HQD's
10 bad debt exposure due its end use customer base. HQT carries greater risk
11 in terms of capital exposure. This risk differential may be accounted for
12 through a difference in ROE or, as in other Canadian jurisdictions, through
13 a differential in deemed capital structure. Based on Concentric's analysis, we
14 find that the current five percent differential in the deemed equity ratio
15 between HQD and HQT continues to be reasonable given the differences in
16 risk between the two entities.

1 **IX. COST OF EQUITY METHODOLOGY AND RESULTS**

2 **Q. Please briefly discuss the ROE in the context of the regulated rate of return.**

3 A. Regulated utilities primarily use common stock, preferred stock and long-term debt
4 to finance their permanent property, plant, and equipment. The overall rate of
5 return (“ROR”) for a regulated utility is based on its weighted average cost of capital,
6 in which the cost rates of the individual sources of capital are weighted by their
7 percentage of the total capitalization of the company. While the costs of debt and
8 preferred stock can be directly observed, the cost of equity is market-based and,
9 therefore, must be estimated based on observable market information.

10 **Q. How is the required ROE determined?**

11 A. The ROE is estimated using one or more analytical techniques that rely on market-
12 based data to quantify investor expectations regarding required equity returns,
13 adjusted for certain incremental costs and risks. Quantitative models produce a
14 range of results from which the market-required ROE is selected. That selection
15 must be based on a comprehensive review of relevant data and information, and
16 does not necessarily lend itself to a strict mathematical solution. As a general
17 proposition, the key consideration in determining the cost of equity is to ensure that
18 the methodologies employed reasonably reflect investors’ views of the financial
19 markets in general, and the subject company (in the context of the proxy group) in
20 particular.

1 **Q. What methods were used to determine HQD's and HQT's cost of equity?**

2 A. Concentric has considered the results of the CAPM and the DCF method in
3 developing an ROE recommendation for HQD and HQT within the context of the
4 risk analysis discussed earlier in the testimony.

5 **Q. Why is it important to use more than one analytical approach?**

6 A. Analysts and academics understand that ROE models are tools to be used in the
7 ROE estimation process, and that strict adherence to any single approach, or the
8 specific results of any single approach, can lead to flawed conclusions. Concentric
9 therefore employs multiple approaches to estimate the cost of equity. That position
10 is consistent with the *Hope* finding that it is the analytical result, as opposed to the
11 methodology, that is controlling in arriving at ROE determinations. The Régie has
12 cited the *Hope* finding in recent decisions, as follows:

13 [194] Finally, as stated in the Hope decision, “Under the statutory
14 standard of “just and reasonable,” it is the result reached, not the
15 method employed, which is controlling.” In this regard, the US
16 courts have allowed regulatory agencies wide latitude and discretion
17 in determining the best method for fixing a reasonable return on the
18 rate base.

19 [195] The fact that the automatic adjustment formula or any other
20 approach suggested by the experts for the parties before the Régie
21 may or may not be challenged is not a decisive factor; it is the result
22 which is conclusive, as the US Supreme Court stated in Hope: “it is
23 the result reached, not the method employed, which is controlling
24 [....] It is not theory, but the impact of the rate order, which counts
25 [....] The fact that the method employed to reach that result may
26 contain infirmities is not then important”. The Régie considers that
27

1 its duty in this respect is to determine a reasonable rate of return and
2 that the method it uses is a matter of discretion.⁶⁸

3 As such, we have considered the results of the CAPM and the DCF method in
4 developing an ROE recommendation for HQD and HQT.

5 **A. Capital Asset Pricing Model**

6 **1. CAPM Theory**

7 **Q. Please describe the general form of the CAPM.**

8 A. The CAPM is a risk premium approach that estimates the cost of equity for a given
9 security as a function of a risk-free return plus a risk premium (to compensate
10 investors for the non-diversifiable or “systematic” risk of that security). The CAPM
11 is based on a theoretically-derived relationship between a security’s required return
12 and the systematic risk of that security. The theory of the CAPM has been subject to
13 frequent empirical research and testing and has been relied upon in setting the
14 required cost of equity for regulated companies throughout North America. In
15 theory, the CAPM is an appropriate model to determine the required return. As
16 shown in Equation [1], the CAPM is defined by four components, each of which
17 must theoretically be a forward-looking estimate:

⁶⁸ See, for example, Régie de l’énergie, Decision in D-2009-156, part [194-195], English translation.

$$[1] \quad K_e = r_f + \beta(r_m - r_f)$$

where:

K_e = the required ROE for a given security;

β = Beta of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return for the market as a whole.

In this specification, the term $(r_m - r_f)$ represents the Market Risk Premium (“MRP”). According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

$$[2] \quad \beta = \frac{\text{Covariance}(r_e, r_m)}{\text{Variance}(r_m)}$$

where:

r_e = the rate of return for the individual security or portfolio.

The variance of the market return, noted in Equation [2], is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the market reflects the extent to which the return on that security will respond to a given change in the market return. Thus, Beta represents the risk of the security relative to the market.

2. CAPM Analysis

Q. What assumptions are necessary to calculate the CAPM?

1 A. In order to calculate the CAPM, one must provide estimates of the risk-free rate of
2 return, the market risk premium and beta. Since the CAPM is forward looking, it is
3 appropriate to use forward-looking estimates for the input variables, if possible.

4 **Q. Does Concentric have concerns with the application of the CAPM under**
5 **current market conditions?**

6 A. Yes. To the extent the inputs to the CAPM do not reflect investors' expectations for
7 the risk-free rate, the beta coefficient, or the market risk premium, the results of the
8 CAPM may not be reliable. In the current market environment, the CAPM is not
9 producing reliable results because those three inputs are affected by current financial
10 market conditions and monetary policy. Consequently, it is not reasonable to place
11 substantial weight on the CAPM results under current market conditions, without
12 making certain adjustments.

13 **a. Risk Free Rate**

14 **Q. What do you assume as a risk-free rate in your CAPM analysis?**

15 A. To estimate the risk free rate, Concentric relies on the 2013 through 2018 *Consensus*
16 *Economics* forecast of the Canadian 10-year government bond and adds the current
17 spread between 10-year and 30-year government debt. Use of the 2013 through
18 2018 forecast allows for some adjustment from near-term bond yields that are near
19 all-time lows, to higher interest rate levels that investors are factoring into their
20 longer-term expectations. Nonetheless, because current bond yields remain at
21 historical lows, the CAPM is unable to produce reasonable results without additional
22 adjustment. The determination of the market-required cost of equity must consider

1 alternative measures or adjustments to the standard CAPM formula, such as those
2 adjustments presented in this evidence.

3 **Table 3: Risk Free Rate**

30-Year Risk Free Yield	CDN\$
October 2012 Consensus Forecast Average 2013-2018 Forecasts	3.62%
Average Daily Spread between 10- year and 30-year government bonds (February 2013)	0.61%
Average	4.23%

4 **b. Beta**

5 **Q. What is the purpose of beta in the CAPM?**

6 A. Beta is a measure of risk and in this case it measures the volatility of a proxy group
7 company's stock price relative to the aggregate market. It is typically calculated using
8 a linear regression of the change in stock price as compared with the change in a
9 general market index. Beta is the slope of the regression line. High betas (greater
10 than 1.0) indicate greater volatility compared to the market, and therefore relatively
11 greater risk. Conversely, low betas (lower than 1.0) indicate lower volatility
12 compared to the market, and therefore relatively lower risk.

13 **Q. What measures of the Beta coefficient did you use in your CAPM analysis?**

14 A. Concentric considered two alternative sources for the Beta coefficient data, and three
15 alternative methods for computing Beta. According to Value Line, the reported
16 historical beta for each company is based on five years of weekly stock returns and
17 uses the New York Stock Exchange as the market index.⁶⁹ The results have been

⁶⁹ http://www.valueline.com/sup_glossb.html

1 rounded to the nearest five hundredths, and no information is reported regarding the
2 statistical significance of the underlying regression. Bloomberg, on the other hand,
3 produces Beta estimates based on parameters entered by the user. Concentric
4 derives the Bloomberg betas based on five years of weekly stock returns using the
5 S&P 500 and the TSX market indices. Bloomberg results are rounded to the nearest
6 one thousandth and include additional information regarding the statistical
7 significance of the underlying regression. Both Value Line and Bloomberg betas are
8 adjusted to compensate for the tendency of beta to revert toward a market mean of
9 1.0 over time.

10 As discussed later in this section, in order to appropriately estimate the cost of equity
11 using the CAPM, it is necessary to adjust raw betas to a common point of
12 convergence. Concentric used the adjusted betas reported by both Value Line and
13 Bloomberg as the first approach, which is standard practice.⁷⁰ As an alternative
14 approach, betas that revert to the industry average mean beta were used to estimate
15 both proxy groups' average beta coefficients. Those estimates rely on raw betas
16 reported by Bloomberg over a five year holding period, using weekly returns.
17 Individual company raw beta coefficients are adjusted toward the industry mean beta
18 (vs. the market mean of 1.0 which is standard practice) over the same time period
19 based on a two-thirds weighting of the raw beta to a one-third weighting of the
20 respective industry mean beta. Finally, Concentric estimated the straight industry

⁷⁰ Value Line adjusted beta = $0.371 + 0.635 * (\text{raw beta})$. Source: Ibbotson Associates, *2012 Yearbook, Valuation Edition*, p. 78; Bloomberg adjusted beta = $0.33 + 0.67 * (\text{raw beta})$. Source: Bloomberg output.

1 average mean beta as a third measure.⁷¹ The relevant market indices and industry
2 averages differed according to whether a company was included in the Canadian
3 proxy group or the U.S. electric utility proxy group.

4 **Q. Why is it necessary to adjust raw betas?**

5 A. There are two primary reasons to adjust raw betas. First, there have been numerous
6 empirical studies providing evidence that an individual company beta is more likely
7 than not to move towards the market average of 1.00 over time. Second, adjusting
8 beta serves a statistical purpose. Because betas are statistically estimated and have
9 associated error terms, betas that are greater than 1.00 tend to have positive
10 estimated errors and thus tend to overestimate future returns, while betas that are
11 below the market average of 1.00 tend to have negative error terms and
12 underestimate future returns. Consequently, it is necessary to adjust betas toward
13 1.00 in an effort to improve forecasts.⁷² Because current stock prices reflect
14 expected risk, one must use an expected beta (adjusted beta) to appropriately reflect
15 investors' expectations. A raw beta reflects only where the stock price has been
16 relative to the market historically and is an inferior proxy for the expected returns
17 when compared to the adjusted beta.

18 **Q. What empirical studies can you cite as evidence and support that company**
19 **betas do regress toward the market average of 1.00?**

⁷¹ The Industry Index Beta is from the Bloomberg Professional average of five years of weekly betas for S&P utilities index.

⁷² Roger A. Morin, *New Regulatory Finance*, at p. 74.

1 A. There have been several studies to support the reversion of beta towards the market
2 mean.⁷³ In 1971, for example, Blume examined all common stocks listed on the
3 NYSE and found a tendency for a regression of betas towards 1.00. He concluded
4 that:

5 ...there is obviously some tendency for the estimated values of the
6 risk parameter to change gradually over time. This tendency is most
7 pronounced in the lowest risk portfolios, for which the estimated risk
8 in the second period is invariably higher than that estimated in the
9 first period. There is some tendency for the high risk portfolios to
10 have lower estimated risk coefficients in the second period than in
11 those estimated in the first. Therefore, the estimated values of the
12 risk coefficients in one period are biased assessments of the future
13 values, and furthermore the values of the risk coefficients as
14 measured by the estimates of β_i tend to regress towards the means
15 with this tendency stronger for the lower risk portfolios than the
16 higher risk portfolios.⁷⁴ (emphasis added)

17 In 1975, Blume revisited the topic, measuring the statistical significance of the
18 regression tendency. He concluded:

19 A comparison of the portfolio betas in the grouping period, even
20 after adjusting for the order bias, to the corresponding betas in the
21 immediately subsequent period discloses a definite regression
22 tendency. This regression tendency is statistically significant at the
23 five percent level for each of the last three grouping periods, 1940-47,
24 1947-54, 1954-61. Thus, this evidence strongly suggests that there is
25 a substantial tendency for the underlying values of beta to regress
26 towards the mean over time.⁷⁵ (emphasis added)

27 **Q. What Beta has the Régie used in previous decisions, and how does that**
28 **compare to other jurisdictions in Canada?**

⁷³ Ibid.

⁷⁴ Marshall E. Blume, *The Journal of Finance*, Vol. 26, No. 1. (Mar., 1971), at p. 7-8.

⁷⁵ Marshall E. Blume, *The Journal of Finance*, Vol. 30, No. 3. (Jun., 1975), at p. 794.

1 A. In its 2012 Gaz Métro Decision, the Régie determined the benchmark utility beta of
2 0.50 to 0.60. Comparing the beta values relied upon by the Régie in past cases to
3 those relied upon by other regulators throughout Canada, the Régie is on the low
4 end of the spectrum. For instance, the BCUC relied on the beta value range of 0.60
5 to 0.66,⁷⁶ the Newfoundland and Labrador Board of Commissioners of Public
6 Utilities relied on a beta of 0.60,⁷⁷ and the Alberta Utility Commission (“AUC”)
7 relied on a beta range of 0.50 to 0.65.⁷⁸

8 **Q. Has the Régie made any adjustments to the CAPM results to account for low**
9 **Beta coefficients?**

10 A. Yes. In the recent past the Régie has not accepted that utility betas move toward the
11 market average of 1.0 but, rather toward an industry mean of 0.50 to 0.60.⁷⁹ Also, as
12 noted by the Régie in a past Decision:

13 Even though it is a determining factor in the application of the
14 CAPM, it remains difficult to objectively infer the value of the beta
15 based on the market data for the enterprises retained in the samples.⁸⁰

16 **Q. What is your conclusion with regard to whether it is appropriate to adjust raw**
17 **Betas?**

18 A. Concentric concludes that it is appropriate and necessary to adjust raw betas.
19 Especially in the current market environment, raw betas are too low to provide a

⁷⁶ Decision G-158-09: In the Matter of Terasen Gas Inc, Return on Equity and Capital Structure, British Columbia Utilities Commission, December 16, 2009, at 45 at p. 60.

⁷⁷ Reason for Decision Order No. P.U.43 (2009), Newfoundland and Labrador Board of Commissioners of Public Utilities, at p. 20.

⁷⁸ Decision No. 2011-474, Alberta Utilities Commission, 2011 Generic Cost of Capital, December 8, 2011, at p. 14.

⁷⁹ Decision 2010-147, Régie de l'énergie, November 26, 2010, at p. 11.

⁸⁰ Decision-2007-116, Régie de l'énergie, Gaz Métro tariffs effective October 1, 2007, October 15, 2007, at p. 6.

1 reasonable determination of the market-required cost of equity that can be
2 corroborated by other models. In summary, after examining the following betas: 1)
3 market-adjusted Betas; 2) industry-adjusted Betas; and 3) industry index Beta,
4 Concentric determined that the most reasonable beta for HQD's and HQT's CAPM
5 is the average of the market-adjusted Betas and the industry-adjusted betas for each
6 respective proxy group. Using an average of those two measures of Beta reflects the
7 statistical and market practice of adjusting beta coefficients to 1.0, while also
8 reflecting the historical practice of the Régie using an industry beta.

9 **c. Market Risk Premium**

10 **Q. How have you computed the Market Risk Premium?**

11 A. Concentric examined two estimates of the MRP, comprised of an historical (ex-post)
12 estimate and a forward-looking (ex-ante) estimate. To develop those estimates,
13 Concentric first relied upon the long-term historical calculation for the relevant
14 market (i.e., Canada, U.S.) as published by Morningstar. Next, we derived a forward-
15 looking estimate of the MRP using forward projections of the return on the relevant
16 market indices less the relevant risk-free rate.⁸¹ Forward return projections were
17 derived by calculating the implied market ROE on a market-capitalization weighted
18 basis for the individual companies comprising a broad market index. The DCF
19 methodology was used to determine the implied expected market return. For the
20 forward-looking estimate for Canada and the U.S., Concentric calculated an MRP of
21 6.14 percent and 8.55 percent, respectively.

⁸¹ See Exhibit JMC-7.

In the U.S., Morningstar/Ibbotson risk premia data are available from 1926-2011 and result in a 6.60 percent risk premium, the arithmetic mean of the premium of the returns on the S&P 500 over long-term government bond income returns. In Canada, the longest period for which risk premia data were available from Morningstar/Ibbotson is from 1936-2011 in Canadian currency, which yields an equity risk premium of 5.38 percent; and from 1939-2011 in U.S. dollars, yielding a 5.99 percent equity risk premium. The Canadian market is represented by the S&P/TSX Composite Index and earlier sources provided by Ibbotson Associates.⁸² After an examination of the four MRP values discussed above, Concentric determined that a reasonable MRP would be the average of those four values, or 6.67 percent, equally weighting both historic and projected MRPs for both Canadian and U.S. markets.

Table 4: Market Risk Premium Values

	Canadian MRP	U.S. MRP
Historical MRP	5.38%	6.60%
Forward-looking MRP	6.14%	8.55%
Average	6.67%	

Q. Why is it appropriate to use the arithmetic mean of the historic market risk premiums?

A. It is appropriate to use the arithmetic mean of the historic MRPs because the arithmetic mean, as opposed to the geometric mean, is the simple average of single

⁸² Ibbotson Associates, *2012 Risk Premia Over Time Report*, Estimates from 1926-2012; Ibbotson - *Canadian Risk Premia over Time Report 2006*; and Morningstar International Equity Risk Premia Report 2012.

1 period rates of return. The geometric mean, in contrast, is the compound rate that
2 equates a beginning value to its ending value. The important distinction between the
3 two methods is that the arithmetic mean treats each periodic return as an
4 independent observation and, therefore, incorporates uncertainty into the calculation
5 of the long-term average. In his review of literature on the topic, Cooper noted the
6 following rationale for using the arithmetic mean:

7 Note that the arithmetic mean, not the geometric mean is the
8 relevant value for this purpose. The quantity desired is the rate of
9 return that investors expect over the next year for the random annual
10 rate of return on the market. The arithmetic mean, or simple
11 average, is the unbiased measure of the expected value of repeated
12 observations of a random variable, not the geometric mean. ...[the]
13 geometric mean underestimates the expected annual rate of return.⁸³

14 For the purposes of the CAPM analysis, therefore, the historic arithmetic mean of
15 the equity market returns over long-term government bond income returns as
16 reported by Ibbotson Associates is used, along with the forward-looking market
17 estimate.

18 3. CAPM Results

19 **Q. How did you apply your CAPM analysis?**

20 A. Concentric relied on the average of the historical and forecasted MRP estimates
21 noted above, the average of the market- and industry-adjusted betas for the U.S.
22 electric utility proxy group of 0.59, and the 4.23 percent projected yield on the
23 Canadian long-term government bond. As indicated earlier, Concentric found that
24 the U.S. electric utility proxy group is more closely comparable to HQD and HQT

⁸³ Ian Cooper, "Arithmetic versus geometric mean estimators: Setting discount rates for capital budgeting," *European Financial Management* 2.2 (1996): 158.

from a risk perspective. As such, it is appropriate to rely on the U.S. electric utility proxy group's average beta coefficient, rather than the Canadian proxy group's Beta in estimating HQD's and HQT's required ROE. The results of the CAPM analysis, including flotation costs, are provided in Table 5 and are shown in detail in Exhibit JMC-6. Finally, we made a further adjustment of 0.75 percent to reconcile the differences between the CAPM results and the DCF model. This adjustment is consistent with the Régie's approach factoring in the adjustment for "Results of Other Models".⁸⁴

Table 5: Reconciled CAPM Results

	Reconciled CAPM (US Proxy Group)
Risk Free Rate	4.23%
Beta	0.59
Market Risk Premium	6.67%
Sub-Total	8.17%
Flotation Cost	0.30%
Sub-Total	8.47%
Adjustment for Other Models	0.75%
Total	9.22%

Q. Have you examined previous Régie Decisions and expert evidence filed in past case where the CAPM was analyzed?

A. Yes. Table 6 compares the Régie's final CAPM determination in the 2011 Gazifere case, inputs of Dr. Roger Morin and Dr. Laurence Booth from the previous two Gaz

⁸⁴ Decision 2010-147, Régie de l'énergie, November 26, 2010, at p. 28. Decision D-2009-156, Régie de l'énergie, December 7, 2009, at p. 27. [English Version]

1 Métro rate cases, as well as the Régie’s final CAPM determination in the 2012 case.
2 Table 7 also includes the range of inputs provided by Dr. Booth in the recent
3 Intragaz, Inc. (“Intragaz”) ROE proceeding and the CAPM inputs filed by
4 Concentric in Gaz Métro’s most recent (2013) ROE evidence.⁸⁵ As shown, there is a
5 wide range of CAPM results based on various assumptions used for the risk free rate,
6 the market risk premium and beta coefficient estimates.

⁸⁵ Intragaz did not file a CAPM analysis in its 2013 return on equity evidence.

1

Table 6: Various CAPM Inputs for Recommended and Allowed ROEs

	Gazifere 2011 Rate Case		Gaz Métro 2012 Rate Case					Intragaz 2013 Rate Case		Gaz Métro 2013 Rate Case
	<u>Régie</u>	<u>Régie</u>	<u>Morin</u>	<u>Booth</u>	<u>Booth</u>	<u>Régie</u>	<u>Régie</u>	<u>Booth</u>	<u>Booth</u>	<u>Coyne CAPM Reconciled</u>
Risk-Free Rate	4.15%	4.50%	4.40%	4.50%	4.50%	3.91%	4.50%	3.00%	3.00%	3.75%
Beta	0.50	0.55	0.70	0.45	0.55	0.50	0.60	0.45	0.55	0.65
x Market Risk Premium	5.50%	5.75%	6.70%	5.00%	6.00%	5.50%	5.75%	5.00%	6.00%	6.94%
Proxy Group Risk Premium	2.75%	3.16%	4.69%	2.25%	3.30%	2.75%	3.45%	2.25%	3.30%	4.54%
Straight CAPM Calculation	6.90%	7.66%	9.09%	6.75%	7.80%	6.66%	7.95%	5.25%	6.30%	8.29%
Flotation Cost	0.50%	0.50%	0.30%	0.50%	0.50%	0.30%	0.40%	0.50%	0.50%	0.30%
"Simple" CAPM	7.40%	8.16%		7.25%	8.30%	6.96%	8.35%	5.75%	6.80%	8.59%
Risk Adjustment	0.25%	0.50%				0.25%	0.35%			
Adjustment for Other Models	0.25%	0.50%				0.25%	0.50%			0.75%
Excess Credit Spreads	0.25%	0.55%		0.25%	0.40%	0.25%	0.40%	0.40%	0.40%	
Operation Twist								0.80%	0.80%	
Total	8.15%	9.71%	9.39%	7.50%	8.70%	7.71%	9.60%	6.95%	8.00%	9.34%
Recommended ROE			9.39%	8.10%				7.50%		9.34%
Allowed ROE	9.10%					8.90%				8.90%

*The 9.34% CAPM result above may not calculate due to rounding.

2
3

1 **Q. Please describe the areas where your analysis diverges from the assumptions and**
2 **determinations shown in Table 6.**

3 A. There are a few key areas where Concentric's analysis diverges from the CAPM assumptions
4 provided in Table 6. Specifically, we disagree with Dr. Booth's beta coefficient estimates, his
5 MRP estimates and his sole reliance on the traditional CAPM analysis. The resulting
6 "Simple CAPM" estimates demonstrate that the traditional CAPM does not work in the
7 current market environment without adjustments. Dr. Booth's adjustments for "Excess
8 Credit Spreads" (Gaz Métro) and combined with "Operation Twist" (Intragaz) are
9 inadequate to overcome the problems with the beta and market risk premium, which are too
10 low to produce reliable ROE estimates.

11 **Q. Why do you disagree with the beta coefficients generally relied upon by Dr. Booth?**

12 A. Dr. Booth's beta coefficient of 0.45 to 0.55 is unsupported by any publicly available beta
13 coefficient estimates that are used by investors on a day-to-day basis. In a data response
14 filed by Dr. Booth in the 2012 Gaz Métro rate case, he cites a study completed by Gombala
15 and Kahl and notes that: "the only paper that Dr. Booth is aware of that applies beta
16 forecasting models to utilities is the Gombala and Kahl paper in Financial
17 Management....This paper shows that utility betas revert to their own grand mean and not
18 the grand mean of all stocks which is 1.0."⁸⁶ In that data response, Dr. Booth did not quote
19 the Gombala paper verbatim. What it actually states is:

20 The results of this study, however, indicate that 1.0 is too high an underlying
21 mean for most utilities. Instead, they should be adjusted toward a value that

⁸⁶ Dr. Booth's answers to Gaz Métro's Information Requests, August, 2011, Data Request No. 16c.

1 is less than one. For Consolidated Edison, an underlying mean of 0.7 would
2 be more appropriate.⁸⁷

3 This study is over 20 years old and is focused on a single utility. Other than this document,
4 Dr. Booth did not cite any other studies, papers or estimates that would confirm that the
5 grand mean of 0.45 to 0.50 is reasonable. It should be further noted that all beta values used
6 by experts for purposes of the CAPM analysis are adjusted in some way, including the betas
7 used by Dr. Booth. What is most troubling about Dr. Booth's beta range of 0.45 to 0.55
8 noted above is that he has not presented any specific analysis to support how he determined
9 that range or how it can be used or relied upon prospectively.

10 **Q. Have regulators also determined that Dr. Booth's beta estimate is not consistent with**
11 **the practices used by financial analysts?**

12 A. Yes, in its 2009 Decision, the BCUC stated:

13 The Commission panel will give weight to the CAPM approach, but
14 considers that the relative risk factor should be adjusted in a manner
15 consistent with the practice generally followed by analysts, so that it yields
16 the result that accords with common sense and is not patently absurd.⁸⁸

17 Further, the Board of Commissioners of Public Utilities for Newfoundland & Labrador also
18 declined to adopt Dr. Booth's beta coefficients:

19 The Board notes that the actual beta has not been within the historical
20 average since 1998. (Transcript, Oct. 22, 2009, pg.19/17-25) While the
21 starting point is the historical average beta (which Ms. McShane refers to as a
22 raw beta) the additional analysis performed by Ms. McShane provides other
23 perspectives suggesting the historic average should be adjusted. The Board
24 agrees with Dr. Booth that utilities are a low beta stock. However, given that
25 betas have not recently been within historical norms and in light of the

⁸⁷ Time Series Processes of Utility Betas: Implications for Forecasting Systematic Risk, Michael J. Gombola and Douglas R. Kahl, Financial Management/Autumn 1990.

⁸⁸ Decision G-158-09: In the Matter of Terasen Gas Inc, Return on Equity and Capital Structure, British Columbia Utilities Commission, December 16, 2009, at p. 45.

financial market conditions, the Board does not expect that the beta will be within historical averages for 2010. In this circumstance the Board relies on the evidence of Ms. McShane that there should be an upward adjustment. The Board believes that, based on the evidence, a reasonable beta for Newfoundland Power is 0.60.⁸⁹

Q. Please explain why you disagree with the market risk premium used by Dr. Booth as noted in Table 6.

A. Dr. Booth's MRP estimate of 5.0 percent to 6.0 percent is based significantly on studies developed by Professor Pablo Fernandez. Those studies can be viewed as problematic because studies based on surveys do not reflect the views of actual market participants. Moreover, Professor Fernandez's 2011 and 2012 surveys provide the following MRPs for the U.S. and Canada:

Table 7: Recent Fernandez MRP Survey Results⁹⁰

	2012	2011
United States	5.5%	5.5%
Canada	5.4%	5.9%

Although Concentric does not agree that these types of survey results should be used in the calculation of the CAPM, these updated survey results would not support Dr. Booth's contention that the MRP in Canada is significantly lower than the MRP in the U.S.

Q. Do you agree with Dr. Booth's sole reliance on the CAPM analysis to estimate a company's return on equity?

⁸⁹ Reason for Decision Order No. P.U.43 (2009), Newfoundland and Labrador Board of Commissioners of Public Utilities, at p. 20.

⁹⁰ Market Risk Premium used in 82 countries in 2012, a survey with 7,192 answers, Pablo Fernandez, Javier Aguirreamalloa and Luis Corres, June 19, 2012, at 3. Market Risk Premium used in 56 countries in 2011: a survey with 6,014 answers, Pablo Fernandez, Javier Aguirreamalloa and Luis Corres, April 25, 2011, at 3.

1 A. No. As discussed earlier in this evidence, regulators in British Columbia recently adopted
2 the DCF analysis as the primary method for determining ROE in a case involving Terasen
3 Gas. Moreover, other jurisdictions in Canada have not limited their ROE determinations to
4 just one method, but rather use two or more methods. The OEB concluded that several
5 analytical tests can provide value: “The Board finds that each of the analytical tests has value
6 as each provides a different perspective on the question of the appropriate ROE.”⁹¹ Finally,
7 it is interesting to note that Professor Fernandez (the same person cited by Dr. Booth in his
8 2011 Gaz Métro evidence) has provided evidence that the CAPM does not work and has
9 concluded that historical betas are useless to estimate the expected return of companies.⁹²

10 **Q. Do you agree with Dr. Booth’s assertion that “the most important thing is to use the**
11 **right estimation technique and not necessarily a variety of techniques”?**⁹³

12 A. No, we do not. As stated previously in our testimony, it is preferable to use multiple
13 methodologies when estimating the cost of equity because each methodology provides a
14 different perspective. Both the DCF method and the CAPM are based on different
15 assumptions, and have strengths and weaknesses depending on the economic and financial
16 market conditions. As such, no individual financial model should be used to estimate the
17 cost of equity on a stand-alone basis without considering the results of other approaches and
18 without applying informed judgment.

⁹¹ Decision with Reasons, Ontario Energy Board, EB-2007-0905, November 3, 2008, at 157.

⁹² Are calculated betas worth for anything?, Pablo Fernandez, IESE Business School, University of Navarra, October 16, 2008, at p. 2 and p. 18.

⁹³ Reason for Decision Order No. P.U.43 (2009), Newfoundland and Labrador Board of Commissioners of Public Utilities, at p. 15.

1 **4. The CAPM Approach and the Régie**

2 **Q. Should the Régie consider modifications such as those it has made in the past**
3 **related to the beta coefficient, the risk-free rate and the MRP?**

4 A. Yes. As shown in Table 6, the adjustments made to the “Simple CAPM,” including the Gaz
5 Métro risk adjustment, the adjustment for “Results of Other Models”, and the adjustments
6 for “Excess Credit Spreads” and for “Operation Twist” are all remedies used to adjust the
7 underlying inputs used in the CAPM calculation.

8 **Q. Please discuss the CAPM adjustments the Régie has made in the past.**

9 A. In its recent Decisions, the Régie retained an MRP of 5.50 percent to 5.75 percent for the
10 “Simple CAPM” and allowed an adjustment between 0.25 percent and 0.55 percent to take
11 into account the effect on the corporate bond yield spread during the financial crisis and
12 directly associated this adjustment with the MRP.⁹⁴ While Concentric’s recommended MRP
13 of 6.67 percent is higher, it is important to note that it does not require an adjustment for
14 “Excess Credit Spreads” since we rely, in part, on forward-looking estimates that account for
15 the higher credit spreads. Also, Concentric has given equal weight to the Canadian and U.S.
16 MRP, consistent with the Régie’s approach in recent Decisions.

17 [217] The Régie also emphasizes that in its decision D-2009-156, for
18 estimating the market risk premium, it used equal proportions of Canadian
19 and American data. The Régie uses the same approach, taking account of the
20 evidence in this case.⁹⁵

⁹⁴ Decision 2011-182, Régie de l’énergie, November 25, 2011, at 76. [English Version] Decision 2010-147, Régie de l’énergie, November 26, 2010, at p. 19. [English Version] Decision D-2009-156, Régie de l’énergie, December 7, 2009, at p. 27. [English Version]

⁹⁵ Decision D-2011-182, Régie de l’énergie, November 25, 2009, at p. 57.

1 Similarly, the Régie has recognized that the CAPM has to be adjusted when the risk-free rate
2 is significantly below its historical average. In one case, it adjusted the final CAPM
3 determination by 40 basis points⁹⁶ and in another case adjusted the CAPM determination by
4 a range of 25 to 50 basis points.⁹⁷ In addition, Dr Booth, in his Intragaz evidence, refers to
5 an 80 basis point adjustment that he justifies by reference to the effects of “Operation
6 Twist”. However, as explained above, the risk-free rate Concentric has used in the CAPM
7 analysis in this testimony relies on the 2013 through 2018 forecast yield for the Canadian
8 long government bond, which reflects the current market reality that near-term bond yields
9 are at all-time lows, and that investors factor higher interest rate levels into their longer-term
10 expectations. As such, there is no need for a specific adjustment for the low level of the
11 risk-free rate, other than the adjustment for the “Results of Other Models” that Concentric
12 has utilized.

13 Finally, in the same Decisions, the Régie adjusted the “Simple CAPM” determination by 25
14 to 35 basis points because it recognized that the beta coefficient did not account for Gaz
15 Métro’s higher business risk in that case.⁹⁸ However, the Beta of 0.59 that Concentric has
16 used in this testimony properly represents HQD’s and HQT’s risk level, which we believe is
17 more comparable to the U.S. electric utility proxy group.

18 **Q. Does your final CAPM recommendation align with the Régie’s previous ROE**
19 **determinations?**

⁹⁶ Decision D-2007-116, Régie de l’énergie, October 15, 2007, at p. 7. [English Version]

⁹⁷ Decision D-2009-156, Régie de l’énergie, December 7, 2009, at 27. [English Version] Decision D-2010-147, Régie de l’énergie, November 26, 2010 at p. 19. [English Version]

⁹⁸ Decision 2011-182, Régie de l’énergie, November 25, 2011, at p. 76. [English Version] Decision D-2009-156, Régie de l’énergie, December 7, 2009, at p. 69. [English Version]

1 A. Yes, it does. But rather than the three separate adjustments made by the Régie, amounting
2 to 75 to 155 basis points (Gazifere) or 75 to 125 basis points (Gaz Métro), Concentric has
3 reconciled the CAPM with a single 75 basis point adjustment. This adjustment is
4 comparable to the Régie's "Results of Other Models" adjustment, as shown in Table 6.

5 **B. Discounted Cash Flow ("DCF") Model**

6 **1. DCF Theory**

7 **Q. Please summarize the theory behind the DCF model.**

8 A. The DCF model evolves from the principle that investors will value a given investment
9 according to the present value of its expected future cash flows over time. This model is
10 widely used in valuing entire companies by discounting the projected cash flows for the
11 enterprise. When valuing the entire enterprise, financial analysts discount the future stream
12 of free cash flows. When considering the common stock of a company, investors consider
13 the future stream of dividends as cash flow from this investment (characterized by the
14 Dividend Discount Model). Efficient markets price a stock according to these expectations,
15 leading to the expression shown in Formula [3]:

$$P = \frac{D_1}{(1+r)^1} + \frac{D_2}{(1+r)^2} + \dots + \frac{D_n}{(1+r)^n} \quad [3]$$

Assuming a constant growth rate in dividends, the model may be rearranged to compute the ROE accordingly, as shown in Formula [4]:

$$r = \frac{D}{P} + g \quad [4]$$

where:

P = the current stock price
 g = the dividend growth rate
 D_n = the dividend in year n
 r = the cost of common equity.

Stated in this manner, the cost of common equity is equal to the dividend yield plus the dividend growth rate.

Q. What are the assumptions underlying the Constant Growth DCF model?

A. The Constant Growth DCF model is based on the following assumptions: (1) a constant average growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate. There are other forms of the DCF model that allow for changes in the growth rate assumption if there is reason to believe that investors do not expect a steady growth rate in perpetuity. The Multi-Stage form of the DCF model, for example, sets the subject company's stock price equal to the present value of future cash flows received over several (e.g., two or three) "stages". Cash flows are defined as projected dividends, which increase at the growth rate specific to each stage.

1 **2. Growth Rate Estimates**

2 **Q. What are the sources of growth in a company's earnings and dividends?**

3 A. The sources of growth in a company's earnings and dividends are influenced by the
4 investment opportunities and strategies that a company pursues. Utilities generally achieve
5 growth through a combination of service territory expansion, financing structure and
6 operating efficiency. All of the expected sources of growth in a company are reflected
7 through its current stock price, and the resulting dividend yield used in the DCF analysis. It
8 is the growth expectation embedded in those dividend yields that an analyst must estimate in
9 conducting a DCF analysis.

10 **Q. Is the growth rate a key assumption in the use of the DCF model?**

11 A. Yes. Estimating investors' expectations of future growth for the proxy companies is an
12 important factor in the DCF model. Since the growth rate used in the DCF model is an
13 estimate of future growth, there is no precise estimation methodology. Investors and
14 analysts consider historical growth rates in their estimation of future growth rates, but past
15 growth rates may be misleading because they may represent circumstances and operations
16 that cannot be repeated in the future. For example, it is highly unlikely that historical
17 averages over periods with widely varying rates of inflation, interest rates and costs of capital,
18 such as have recently been experienced, will be representative of current growth rate
19 expectations. Therefore, historical growth rates are not the best source of growth rates to be
20 used in the DCF model.

21 **Q. Is it reasonable to assume that investors have reviewed historical growth rates in**
22 **developing their estimates of future growth for a company?**

1 A. Yes. For that reason, the use of projected growth rates provides investors' understanding of
2 the historical performance of the company as well as their expectations for the future.
3 Typically, investors rely on expected earnings growth rates for several reasons. First,
4 although the DCF model is based on dividend growth rates, a company's dividend growth is
5 derived from and can only be sustained by earnings growth. Second, in order to reduce the
6 long-term growth rate to a single measure, as is required in the Constant Growth DCF
7 model, it is necessary to assume a constant payout ratio, and constant growth rate in earnings
8 per share, dividends per share and book value per share. Third, since earnings growth rates
9 are least influenced by capital allocation decisions that directly affect near-term dividend
10 payout ratios, estimates of earnings growth are more indicative of long-term investor
11 expectations than are dividend growth estimates. Finally, analysts' forecasts of earnings per
12 share growth are widely available, while dividend and book value growth rates are not
13 generally estimated by analysts.⁹⁹

14 **Q. Are projected earnings growth rates for utility companies generally available?**

15 A. Yes, projected earnings growth rates are generally available. For example, analysts' five-year
16 earnings growth rates are publicly available from Zacks' Investor Services for U.S.
17 companies. Thomson First Call (as reported on Yahoo! Finance), which is a public source,
18 and SNL Financial, a subscription-based service, publish earnings growth rates for both
19 Canadian and U.S. companies. All of these services provide consensus estimates that
20 compile projections of earnings growth from several analysts. Value Line, which is a

⁹⁹ Value Line Investment Survey is the only publication of which Concentric is aware that projects dividend and book value growth rates. Those estimates represent the Value Line analyst's perspective on dividend and book value growth. In contrast, many of the earnings growth rates that are publicly available are consensus estimates with contributions provided by several analysts.

1 subscription based publication, provides three-to-five-year projected earnings, dividend and
2 book value growth rates based on the expectations of an individual analyst.

3 **Q. How long have consensus earnings growth rate forecasts been available for Canadian**
4 **utility companies?**

5 A. SNL Financial began compiling consensus earnings growth estimates for Canadian utility
6 companies in February of 2012. In addition, Thomson First Call also provides long-term
7 growth estimates for Canadian utilities. This is a key change in circumstances from prior
8 cases before the Régie and addresses one of the Régie's previous concerns with using the
9 DCF model. Specifically, in the Régie's 2011 decision concerning Gaz Métro's rate of
10 return, the only significant problem identified with using the DCF method was that: "...it is
11 difficult to obtain a reliable estimator of the dividend growth rate as the financial analysts do
12 not produce growth forecasts for Canadian regulated companies."¹⁰⁰

13 **3. Reliability of Analysts' Growth Rates**

14 **Q. Is there academic support for the use of analysts' earnings growth estimates in the**
15 **DCF model?**

16 A. Yes, there is significant academic support for the use of analyst growth rates. The
17 relationship between various growth rates and stock valuation metrics has been the subject
18 of much academic research. Many published articles specifically support the use of analysts'
19 earnings growth projections in the DCF model in general, as well as for a method of
20 calculating the expected market risk premium in particular. A 1986 article by Dr. Robert
21 Harris, for example, demonstrated that financial analysts' earnings forecasts (referred to in

¹⁰⁰ Decision D-2011-182, Régie de l'énergie, November 25, 2011, at paragraph [193].

1 the article as “FAF”) in a Constant Growth DCF formula are an appropriate method of
2 calculating the expected market risk premium.¹⁰¹ In that regard, Dr. Harris noted that:

3 [...] a growing body of knowledge shows that analysts’ earnings forecasts are
4 indeed reflected in stock prices. Such studies typically employ a consensus
5 measure of FAF calculated as a simple average of forecasts by individual
6 analysts.¹⁰²

7 Dr. Harris further noted that,

8 Given the demonstrated relationship of FAF to equity prices and the direct
9 theoretical appeal of expectational data, it is no surprise that FAF have been
10 used in conjunction with DCF models to estimate equity return
11 requirements.¹⁰³

12 In a 1988 article, Professors Carleton and Vander Weide performed a study to determine
13 whether projected earnings growth rates are superior to historical measures of growth in the
14 implementation of the DCF model.¹⁰⁴ Although the purpose of that study was to
15 “investigate what growth expectation is embodied in the firm’s current stock price,”¹⁰⁵ the
16 authors clearly indicate the importance of earnings projections in the context of the DCF
17 model. Professors Carleton and Vander Weide concluded that:

18 [...] our studies affirm the superiority of analysts’ forecasts over simple
19 historical growth extrapolations in the stock price formation process.
20 Indirectly, this finding lends support to the use of valuation models whose
21 input includes expected growth rates.¹⁰⁶

¹⁰¹ Robert S. Harris, *Using Analysts’ Growth Forecasts to Estimate Shareholder Required Rates of Return*, Financial Management, Spring 1986 at p. 66.

¹⁰² *Ibid.*, at p. 59.

¹⁰³ *Ibid.*, at p. 60.

¹⁰⁴ James H. Vander Weide, Willard T. Carleton, *Investor growth expectations: Analysts vs. history*, The Journal of Portfolio Management, Spring 1988.

¹⁰⁵ *Ibid.*, at p. 78.

¹⁰⁶ *Ibid.*, at p. 82.

1 Similarly, in a 1992 article, Harris and Marston presented “estimates of shareholder required
2 rates of return and risk premia which are derived using forward-looking analysts’ growth
3 forecasts”.¹⁰⁷ In addition to other findings, Harris and Marston reported that,

4 [...] in addition to fitting the theoretical requirement of being forward-
5 looking, the utilization of analysts’ forecasts in estimating return
6 requirements provides reasonable empirical results that can be useful in
7 practical applications.¹⁰⁸

8 More recently (2004), the Carleton and Vander Weide study was updated to determine
9 whether the finding that analysts’ earnings growth forecasts are relevant in the stock
10 valuation process still holds. The results of that updated study continued to demonstrate the
11 importance of analysts’ earnings forecasts, including the application of those forecasts to
12 utility companies.¹⁰⁹ Similarly, Brigham, Shome and Vinson noted that “evidence in the
13 current literature indicates that (1) analysts’ forecasts are superior to forecasts based solely on
14 time series data; and (2) investors do rely on analysts’ forecasts.”¹¹⁰

15 **Q. What is “optimism bias” in the earnings growth rate forecasts of security analysts,**
16 **and how would it affect an estimate of the ROE?**

17 A. Optimism bias is related to the alleged tendency for analysts to forecast earnings growth
18 rates that are higher than are actually achieved. If optimism bias were present in analysts’
19 earnings forecasts, it could create an upward bias in the estimated cost of capital that results
20 from the DCF approach.

¹⁰⁷ Robert S. Harris, Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts’ Growth Forecasts*, Financial Management, Summer 1992.

¹⁰⁸ *Ibid.*, at p. 63.

¹⁰⁹ Advanced Research Center, *Investor Growth Expectations*, Summer, 2004.

¹¹⁰ *The Risk Premium Approach to Measuring a Utility’s Cost of Equity*, Financial Management, Spring 1985.

1 **Q. Is it reasonable to believe that analysts' earnings growth estimates currently may be**
2 **overly optimistic or may represent a conflict of interest?**

3 A. No. Several regulatory changes have been implemented that are designed to provide fair
4 disclosure and eliminate analysts' bias. On August 15, 2000, the U.S. Securities and
5 Exchange Commission ("SEC") adopted Regulation FD to address the selective disclosure
6 of information by publicly traded companies and other issuers. Regulation FD provides that
7 when an issuer discloses material information, the issuer must publicly disclose that
8 information to all investors at the same time. In this way, the new rule aims to promote full
9 and fair disclosure.

10 **Q. Have there been other regulatory changes that affect the interaction between analysts**
11 **and investors?**

12 A. Yes. In 2002 the SEC, the New York Stock Exchange, the New York Attorney General,
13 and other state regulators introduced guidelines regarding the interaction between analysts
14 and investment banks that has become known as the Global Analysts Research Settlement.
15 The Global Settlement outlines the following structural reforms that limit the interaction
16 between analysts and investment banks:

- 17 • The firms will separate research and investment banking, including physical separation,
18 completely separate reporting lines, separate legal and compliance staffs, and separate
19 budgeting processes.
- 20 • Analysts' compensation cannot be based directly or indirectly upon investment banking
21 revenues or input from investment banking personnel.
- 22 • Investment bankers cannot evaluate analysts.

- 1 • An analyst's compensation will be based in significant part on the quality and accuracy of
- 2 the analyst's research.
- 3 • Decisions concerning compensation of analysts will be documented.
- 4 • Investment bankers will have no role in determining what companies are covered by the
- 5 analysts.
- 6 • Research analysts will be prohibited from participating in efforts to solicit investment
- 7 banking business, including pitches and road shows.
- 8 • Firms will implement policies and procedures reasonably designed to assure that their
- 9 personnel do not seek to influence the contents of research reports for purposes of
- 10 obtaining or retaining investment banking business.
- 11 • Firms will create and enforce firewalls between research and investment banking
- 12 reasonably designed to prohibit improper communications between the two.
- 13 Communications should be limited to those enabling research analysts to fulfill a
- 14 “gatekeeper” role.
- 15 • Each firm will retain, at its own expense, an Independent Monitor to conduct a review to
- 16 provide reasonable assurance that the firm is complying with the structural reforms.
- 17 This review will be conducted eighteen months after the date of the entry of the Final
- 18 Judgment, and the Independent Monitor will submit a written report of his or her
- 19 findings to the SEC, NASD, and NYSE within six months after the review begins.¹¹¹

20 **Q. Has any research been conducted to measure whether analyst forecast bias exists**
21 **since the Global Settlement was implemented?**

¹¹¹ U.S. SEC Fact Sheet on the Global Settlement. The Global Settlement was finalized on April 28, 2003; however, the reforms were introduced and discussed prior to being finalized.

1 A. Yes. A 2010 article in Financial Analyst Journal found that analyst forecast bias has declined
2 significantly or disappeared entirely since the Global Settlement:

3 Introduced in 2002, the Global Settlement and related regulations had an
4 even bigger impact than Reg FD on analyst behavior. After the Global
5 Settlement, the mean forecast bias declined significantly, whereas the median
6 forecast bias essentially disappeared. Although disentangling the impact of
7 the Global Settlement from that of related rules and regulations aimed at
8 mitigating analysts' conflicts of interest is impossible, forecast bias clearly
9 declined around the time the Global Settlement was announced. These
10 results suggest that the recent efforts of regulators have helped neutralize
11 analysts' conflicts of interest.¹¹²

12 4. Predominance of DCF Approach in North American Regulatory

13 Decisions

14 **Q. What are the traditional models used in Canada and the U.S. to estimate the cost of**
15 **equity for regulated utilities?**

16 A. While Canadian regulatory agencies have generally favored the CAPM approach, the DCF
17 model is the predominant method relied on in U.S. state and Federal regulatory proceedings.

18 **Q. What forms of the DCF model are relied on by the FERC?**

19 A. Since the 1980s, the FERC has relied on the DCF model for natural gas pipeline companies
20 and electric transmission and wholesale distribution assets.¹¹³ In Opinion No. 486-B, the
21 FERC provided guidance on how each of the assumptions of the Two-Stage DCF model
22 should be specified for natural gas pipeline companies. Specifically, the FERC relies on
23 analysts' projected earnings growth rates in the first stage and a measure of GDP growth as
24 the long-term growth rate. The FERC relies on a similar form of the Two-Stage DCF model

¹¹² Armen Hovakimian and Ekkachai Saenyasiri, *Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation*, Financial Analysts Journal, Volume 66, Number 4, July/August 2010, at p. 105.

¹¹³ Docket No. PL07-2-000, Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity, Policy Statement, April 17, 2008, at p. 2.

1 to estimate the cost of equity for electric transmission and distribution assets. In that model,
2 the FERC relies on an equal weighting of analysts' projected earnings growth rates and the
3 sustainable growth rate in a constant growth model.

4 **Q. Do U.S. state regulatory commissions generally give primary weight to the DCF**
5 **model in estimating the cost of equity?**

6 A. Yes. Many U.S. state regulatory commissions rely exclusively on the DCF model for
7 estimating the cost of capital or have afforded the results of this model considerable weight
8 in ROE determinations. Based on a review of recent state regulatory commission decisions,
9 at least twelve state commissions have primarily relied on the DCF model for estimating the
10 cost of equity. Furthermore, certain states have a long-standing policy of relying on the
11 DCF model.

12 Alaska

13 Although we consider all ROE analyses submitted to us by expert witnesses,
14 in recent cases we have relied most heavily on the constant growth variant of
15 the DCF model and have indicated our preferred ways of calculating it. We
16 continue to give the most weight to constant growth DCF analyses in this
17 case. We believe that weighting is appropriate under current economic
18 conditions.¹¹⁴

19 District of Columbia

20 In its decisions, the Commission has relied primarily on the DCF method to
21 determine a utility's cost of common equity because the Commission
22 consistently has found that the DCF method produces more reasonable
23 results than those of other calculation methods. Nevertheless, the
24 Commissions' preference for the DCF method does not preclude
25 consideration of other methods for calculating the cost of equity. The
26 Commission has taken into account the results of the various approaches
27 (DCF, CAPM, and Risk Premium) in estimating the ROE in this proceeding.

¹¹⁴ Regulatory Commission of Alaska, Docket No. U-10-29, Order No. 15, September 2, 2011, at p. 26.

1 The Commission, however, will focus on the DCF model (relying primarily
2 on forecasted growth rates) to determine the appropriate ROE.¹¹⁵

3 Illinois

4 Historically speaking, the Commission has relied heavily on the constant
5 growth DCF model; however, in recent years the Commission has tended to
6 favor the multi-stage DCF model over the constant growth model due to
7 concerns about the sustainability of analysts' growth rate estimates . . . The
8 Commission would not be surprised if circumstances change such that, at
9 some point in time, it would be appropriate to rely on the constant growth
10 DCF model.¹¹⁶

11 Maryland

12 None of the parties' recommendations for ROE were based purely on the
13 classic DCF analysis, which the Commission has historically preferred and
14 deemed the most reliable basis for estimating return on equity. Consistent
15 with our preference for DCF, we find that the most appropriate estimate of
16 ROE in this case is 9.60, which is the ROE calculated by Staff witness
17 Alvarado using the classic DCF analysis.¹¹⁷

18 New Mexico

19 The DCF model is the traditional method relied on by this Commission to
20 determine return on equity. It has been used by the Commission in the past
21 for many utilities, including PNM Gas Services and its predecessor. See, Final
22 Orders in Case Nos. 2662, 2147, 1787. The DCF methodology is used in a
23 majority of the states and its use by this Commission has been expressly
24 approved by the Supreme Court of New Mexico.¹¹⁸

¹¹⁵ Public Service Commission of the District of Columbia, Docket No. FC-1076, Order No. 15710, March 2, 2010, at p. 25.

¹¹⁶ Illinois Commerce Commission, Docket No. 11-0282, January 10, 2012, at p. 121.

¹¹⁷ Maryland Public Service Commission, Case No. 9267, Order No. 84475, November 14, 2011, at p. 49.

¹¹⁸ New Mexico Public Regulation Commission, Recommended Order in Case No. 06-00210-UT, at p. 19.

1 Utah

2 We continue to place primary reliance upon DCF model results to estimate
3 the cost of common equity. The risk premium models also provide
4 information which can appropriately be considered in determining the cost
5 of common equity in this case.¹¹⁹

6 In contrast, we are not aware of any state regulatory commissions that rely primarily on the
7 CAPM. Furthermore, Massachusetts, for example, has determined that the CAPM has
8 limited or no value in estimating the ROE.

9 The Department has previously found that the traditional CAPM as a basis
10 for determining a utility's cost of equity has limited value and, in some cases
11 no value, because of a number of limitations including questionable
12 assumptions that underlie the model.¹²⁰

13 **Q. Have any public utility commissions in Canada given primary weight to the DCF**
14 **analysis?**

15 A. Yes, the BCUC has given weight to the DCF method in the past and recently adopted the
16 DCF analysis as its primary method for determining ROE in the Terasen Gas case. When
17 determining a fair rate of return in 2006, the BCUC gave weight to both the Equity Risk
18 Premium (“ERP”) and DCF approaches.¹²¹ Again in 2009, the BCUC considered DCF,
19 ERP, and CAPM approaches, but found that the DCF and ERP are the most common
20 approaches and determined “that the DCF approach has more appeal in that it is based on a
21 sound theoretical base, it is forward looking and can be utility specific.”¹²² Overall, the
22 BCUC decided:

¹¹⁹ Utah Public Service Commission, Docket No. D-09-035-023, February 18, 2010, at p. 8-9.

¹²⁰ Massachusetts Department of Public Utilities, Docket Nos. DPU 11-01 and 11-02, August 1, 2011, at p. 414-415.

¹²¹ British Columbia Utilities Commission, In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism, March 2, 2006, at p. 1.

¹²² British Columbia Utilities Commission, In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure, December 16, 2009, at p. 45.

1 Accordingly the Commission Panel determines that in determining a suitable
2 ROE for TGI, it will give the most weight to the DCF approach, some lesser
3 weight to the ERP and CAPM approaches and a very small amount of
4 weight to the CE approach.¹²³

5 For the DCF approach, the BCUC found that U.S. data can act as a proxy for Canadian data
6 and rejected suggestions of analyst bias, noting that no allegations of upward bias have been
7 leveled against utility analysts.

8 Moreover, recently the NEB gave significant weight to a multi-stage DCF model in
9 determining the authorized ROE for TransCanada's Mainline Pipeline, noting:

10 Historically, the Board has not relied on the DCF model to estimate cost of
11 capital, primarily due to the perceived difficulty in accurately estimating
12 growth rates. We note that the recent financial market turmoil generates
13 utility betas lower than their historical average and evidence from both expert
14 witnesses noted that DCF results, in the current environment, were yielding
15 cost of equity estimates higher than those resulting from the CAPM. In the
16 current circumstances, we are of the view it is appropriate to give weight to
17 the multi-stage DCF results in this proceeding. Further, we note that growth
18 rates for relatively stable industry such as utilities are more reliable, which
19 somewhat mitigates concerns about the reliability of analysts' forecasts.

20 ...

21 Both the CAPM and DCF models, in our view, have some shortcomings and
22 some advantages in their application. We believe that giving weight to both
23 models in this case provided a more accurate estimate of the Mainline's cost
24 of capital than would have been provided by the application of either model
25 on its own. We are of the view that by giving weight to both models, the
26 effects of beta decoupling and interest rate sensitivity inherent in the CAPM
27 should be largely accounted for. Further, concerns about the analyst-
28 estimated growth rates used in the DCF model are counterbalanced by lower
29 CAPM results.¹²⁴

30 **5. The DCF Approach and the Régie**

¹²³ Ibid.

¹²⁴ National Energy Board, Reasons for Decision, In the Matter of TransCanada PipeLines Limited, NOVA Gas Transmission Ltd., and Foothills Pipe Lines Ltd. Business and Services Restructuring Proposal and Mainline Final Tolls for 2012 and 2013, RH-003-2011, March 2013, at pp. 182-183.

Q. Has the Régie previously considered multiple methods for determining the cost of equity?

A. Yes. For example, in its Decision D-2011-182 the Régie stated:

[...] as no single method can perfectly reproduce the expected return for investors, the Régie takes into account, for the purposes of assessing the rate of return on Gaz Métro's shareholders' equity, the results from the DCF model [...] [Para. 207]

Similarly, in Decision D-2009-156 the Régie stated:

[...] as no one model can perfectly reproduce investors' return expectations, the Régie is taking into consideration the results of the ECAPM and the DCF model [...] as well as the results of the multi-factor model [...] for its assessment of Gaz Métro's rate of return. [Para. 240]

Q. Has the Régie provided any guidance on the use of the DCF methodology for estimating the ROE?

A. Yes. In the 2011 decision concerning Gaz Métro's rate of return, the Régie declined to consider the DCF methodology, stating "[...] it is difficult to obtain a reliable estimate for the growth rate dividends given the financial analysts do not produce growth forecasts for regulated Canadian utilities."¹²⁵ However, as discussed earlier in our testimony, since that time, both SNL Financial and Thomson First Call now report long-term growth estimates for Canadian utilities, which alleviates the concerns raised previously by the Régie.

6. DCF Analysis and Results

a. Dividend Yield

Q. What is the formula for the dividend yield component of the DCF model?

¹²⁵ D-2011-182, November 25, 2011, at [193].

A. As shown in equation [5] below, the dividend yield component of the DCF model is calculated as follows:

$$[5] \quad Y = \frac{D_0(1+0.5g)^1}{P_0}$$

Q. Why is one half year of growth applied to the dividend in the dividend yield calculation?

A. Since utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. As such, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q. How did you calculate the dividend yields for the companies in your comparison groups?

A. The dividend yields presented were calculated for each company in the Canadian and U.S. proxy groups by dividing the current annualized dividend by the average stock price for each company. The price component of the calculation is based on the average closing prices for the 30-, 90-, and 180-trading days ended February 28, 2013. Those dividend yields are multiplied by the DCF model factor $(1 + 0.5g)$ to reflect expected future dividend increases, to arrive at the dividend yield component of the DCF model.

b. Constant Growth Rate Analysis

Q. Please describe the growth rates used in your Constant Growth DCF analysis.

1 A. The Constant Growth DCF analysis for the Canadian proxy group relies on analysts'
2 forecasts of earnings growth. That DCF analysis recognizes that the consensus of analysts'
3 earnings growth forecasts reflects the most important component of investors' growth rate
4 expectations, and it assumes that the analysts' earnings growth forecasts incorporate all
5 information required to estimate a long-term expected growth rate for a company. As
6 discussed earlier, financial research and empirical literature indicate that analysts' earnings
7 growth forecasts are the best available estimates for future growth rates. Available earnings
8 growth estimates from SNL Financial, Value Line and Thomson First Call for each company
9 in the Canadian proxy group were used.¹²⁶ Those growth rates are shown on Exhibit JMC-9.
10 For the U.S. electric utility proxy group, Concentric used a blended growth rate that
11 combines the analysts' consensus growth rate estimates from Zacks, SNL and First Call and
12 Value Line forecasts. Those growth rates are also shown on Exhibit JMC-9.

13 **c. Retention Growth Rate Analysis**

14 **Q. Did you also consider retention growth rate in your DCF analysis?**

15 A. Yes. For the U.S. electric utility proxy group, Concentric also developed a retention growth
16 DCF estimate. For that model, an average growth rate was developed by blending the
17 average of the earnings growth rates reported by Zacks, SNL Financial, First Call and Value
18 Line with the retention growth rates calculated using data from Value Line. Retention
19 growth is generally a suitable indicator of the minimum level of growth that a company can
20 maintain three to five years in the future. The blended growth rate forecasts that combine
21 those two indicators for the sustainable DCF analysis are shown on Exhibit JMC-10,
22 Schedules 1-3. In the current weak economic environment, it is reasonable to combine

¹²⁶ Zacks growth rates are not available for the Canadian proxy group companies.

retention growth forecasts for the U.S. electric utility proxy group with analysts' earnings forecasts.

Q. How is the retention growth rate calculated?

A. The retention growth rate is based on the premise that future growth in dividends results from a portion of the total return being reinvested into the company, instead of being paid to investors in the form of a dividend. The retention growth rate is calculated based on the following formula:

$$g = (b \times r)$$

Where:

b = the percent of earnings that is retained

r = the book equity of the company

In this formula the “b” and “r” terms should be forward-looking estimates.

Retention of earnings causes an increase in the book value per share and, other factors being equal, increases the amount of earnings that is generated per share of common stock. For example, a company that is expected to earn a return of 9 percent and retain 80 percent of its earnings might be expected to have a growth rate of 7.2 percent, computed as follows:

$$0.80 \times 9\% = 7.2\%$$

On the other hand, another company that is also expected to earn 9 percent but only retains 20 percent of its earnings might be expected to have a growth rate of 1.8 percent, computed as follows:

1 $0.20 \times 9\% = 1.8\%$

2 Thus, the rate of growth in a firm's book value per share is primarily determined by the level
3 of earnings and the proportion of earnings retained in the company.

4 **Q. How did you account for external growth in your retention growth rate calculation?**

5 A. The “br + sv” form of the sustainable growth estimate is meant to reflect growth from both
6 internally generated funds (i.e., the “br” term) and from issuances of equity (i.e., the “sv”
7 term), as shown in Equation [7] below. As noted above, the first term, which is the product
8 of the retention ratio (i.e., “b”) and the expected Return on Equity (i.e., “r”) represents the
9 portion of net income that is “plowed back” into the company as a means of funding
10 growth. The “sv” term, which represents growth from external capital, often is represented
11 as:

12
$$\left(\frac{m}{b} - 1\right) \times \text{Common Shares growth rate [7]}$$

13 where:

14
$$\frac{m}{b} = \text{the market to book ratio.}$$

15 In this form, the “sv” term reflects an element of growth as the product of (1) the growth in
16 shares outstanding, and (2) that portion of the market-to-book ratio that exceeds unity.

17 **Q. What is the data source you relied on to calculate retention growth rates for the U.S.
18 electric utility proxy group in your DCF analysis?**

19 A. Value Line publishes forecasts of data that can be used to calculate retention growth rates for
20 each company three to five years in the future. The derivation of Value Line’s retention
21 growth rates for the U.S. electric utility proxy group is shown on Exhibit JMC-10, Schedule 4.

d. Multi-stage DCF Model

Q. Have you considered any other forms of the DCF model?

A. Yes, in order to address some of the limiting assumptions underlying the Constant Growth form of the DCF model, Concentric also considered the results of a multi-period (three-stage) DCF Model. The Multi-stage DCF model tempers the assumption of constant growth in perpetuity in the Constant Growth DCF model with a three-stage approach: near-term, transitional, and long-term growth.

Q. Please describe your Multi-stage DCF model.

A. The Multi-stage model transitions from near-term growth, (i.e., the average of Value Line, Zacks, SNL Financial and First Call forecasts used in the Constant Growth model) for the first stage (years 1-5) of the analysis, to the long-term forecast of GDP growth for the third stage of the analysis (years 11 and beyond). The second, or transitional stage, connects the near-term growth rate with the long-term growth rate for the transitional period by changing the growth rate each year on a pro rata basis. In the terminal stage, the dividend cash flow then grows at the same rate as nominal GDP into perpetuity. The ROE is the internal rate of return based on the stock price today and the discounted value of all future dividend payments.

The Multi-stage DCF model was applied to both the Canadian and U.S. proxy groups. The assumptions used with respect to the various model inputs are shown in Table 8.

Table 8: Multi-stage DCF Model Assumptions

Model Input		Stage 1	Stage 2	Stage3
Years	Start	1 – 5	6 – 10	>11
Stock Price and Dividend Yields	30, 90 and 180 day average			
Earnings Growth		EPS growth as average of Value Line and First Call, SNL and Zacks (as available) projected growth rates	Transition to long-term GDP growth on arithmetic average basis	Long-term GDP growth

The nominal GDP growth rates for Canada and the U.S. were developed using available data for each country from Consensus Economics, Inc. for the period from 2018-2022. These forecasts are based on real (constant dollar) growth rates and estimates of inflation. The inflation estimate was applied to the estimate of real GDP growth to derive the nominal (post-inflation) GDP growth rate. The estimates of nominal GDP growth that were utilized are summarized in Table 9.

Table 9: Estimates of Nominal GDP Growth¹²⁷

Source	Canada	U.S.
Real GDP Growth	2.0%	2.5%
Inflation	2.0%	2.4%
Nominal GDP Growth	4.04%	4.96%

e. DCF Results

¹²⁷ Consensus Forecasts, for 2018-2022, October 8, 2012, at pp. 3 and 28.

Q. Please summarize your DCF results.

A. The DCF results are summarized on Table 10. As shown on that table, the DCF analyses across all methods indicate an average cost of common equity of 10.71 percent for the Canadian proxy group and 9.41 percent for the U.S. electric utility proxy group, including a 30 basis point adjustment for flotation costs and financial flexibility.

Table 10: DCF Results (including flotation costs)

Market Data Averaging Period	Constant Growth DCF	Sustainable Growth DCF ¹²⁸	Multi-Stage DCF	Average
Canadian Utility Proxy Group				
30-day	11.96%	N/A	9.27%	10.62%
90-day	12.06%	N/A	9.40%	10.73%
180-day	12.12%	N/A	9.47%	10.80%
Average	12.05%		9.38%	10.71%
U.S. Electric Utility Proxy Group				
30-day	9.53%	9.15%	9.38%	9.30%
90-day	9.64%	9.26%	9.50%	9.20%
180-day	9.57%	9.20%	9.43%	9.30%
Average	9.58%	9.20%	9.44%	9.41%

7. Flotation Cost Adjustment

Q. What are flotation costs?

A. Flotation costs are the costs associated with the sale of new issues of common equity. These costs include out-of-pocket expenditures for the preparation, filing, underwriting, and other costs of issuance of common equity.

¹²⁸ Data for the Sustainable Growth model is unavailable from Value Line for Canadian companies.

1 **Q. Does the investor return requirement that is estimated by the CAPM or DCF analysis**
2 **need to be adjusted for flotation costs in order to estimate the cost of equity?**

3 A. Yes. Because the purpose of the allowed rate of return in a regulatory proceeding is to
4 estimate the cost of capital the regulated company would incur to raise money in the
5 “primary” markets, an estimate of the returns required by investors in the “secondary”
6 markets must be adjusted for flotation costs in order to provide an estimate of the cost of
7 capital that the regulated company requires.

8 **Q. Has the Régie typically allowed an adjustment for flotation costs and financial**
9 **flexibility?**

10 A. Yes. The Régie has recently determined that an adjustment of between 30 and 50 basis
11 points constitutes a fair and reasonable adjustment to the results obtained from secondary
12 market information.¹²⁹ Such an adjustment would also apply in this case, in order for
13 HQD’s and HQT’s authorized ROE to reflect the risks associated with issuers of equity in
14 the public markets. Therefore, Concentric has adjusted the CAPM and DCF results by 30
15 basis points for flotation costs.

16 **Q. Is an adjustment for flotation costs reasonable for HQD and HQT despite the**
17 **government ownership structure?**

18 A. Yes. First, from a policy perspective, the HQD and HQT ROEs are established on a stand-
19 alone basis, reflecting the true cost to raise equity capital in the markets. Because companies
20 must pay underwriters a fee to issue new common equity, it is reasonable to reflect that cost
21 in the determination of the market-required ROE for HQD and HQT. Next, because

¹²⁹ See Table 6.

1 regulation is meant to replace competition in terms of price setting, the inclusion of an
2 allowance for flotation costs sends the appropriate price signals to consumers of electricity
3 as to the true cost of electric distribution and transmission service. As such, Concentric has
4 remained consistent with the Régie's historical practice of applying an adjustment for
5 flotation costs and financial flexibility by adjusting the analytical results by 30 basis points.
6 Such an adjustment is at the lower end of the range of flotation cost adjustments historically
7 made by the Régie, which is reasonable considering HQD's and HQT's size and the
8 implications for that size on the cost of issuing new common equity.

9 **X. OVERALL CONCLUSIONS AND RECOMMENDATIONS**

10 **Q. Please summarize the results of your analyses.**

11 A. A summary of our analytical results, including flotation costs, is provided in Table 11.

1

Table 11: ROE Results

Capital Asset Pricing Model				
Inputs		CAPM Reconciled		
Risk Free Rate		4.23%		
Beta		0.59		
Market Risk Premium		6.67%		
Sub-Total		8.17%		
Flotation Cost		0.30%		
Sub-Total		8.47%		
Adjustment for Other Models		0.75%		
Total		9.22%		
Discounted Cash Flow				
Market Averaging Period	Constant Growth	Sustainable Growth	Multi-Stage	Average
Canadian Utility Proxy Group				
Average ROE	11.75%	N/A	9.08%	10.41%
Flotation Cost	0.30%	N/A	0.30%	0.30%
Average ROE with Flotation Cost	12.05%		9.38%	10.71%
U.S. Electric Utility Proxy Group				
Average ROE	9.28%	8.90%	9.14%	9.11%
Flotation Cost	0.30%	0.30%	0.30%	0.30%
Average ROE with Flotation Cost	9.58%	9.20%	9.44%	9.41%

2

1 **Q. Considering the various ROE analyses presented in your testimony, what is your**
2 **recommendation with respect to the appropriate ROE for HQD and HQT?**

3 A. Although the CAPM has been used by experts in the past before the Régie, based on the
4 current capital market conditions and the effect of those conditions on the CAPM at this
5 time, Concentric believes it is now appropriate to place more weight on the DCF model as
6 the basis for the recommended ROE for HQD and HQT. The Régie has previously
7 recognized that the calculation of the ROE required consideration of alternative models.
8 Furthermore, as discussed in greater detail in Section VIII, Concentric has analyzed the risks
9 of a carefully-selected proxy group of U.S. electric utility companies and compared those
10 risks to the risks of HQD and HQT. The results of that comparison demonstrate that the
11 U.S. electric utility proxy group is more comparable to HQD and HQT than the Canadian
12 utility proxy group. Concentric, therefore, places greater weight on the U.S. electric utility
13 proxy group in forming the basis of the recommended ROE.

14 The results produced by the various methods and inputs cover a broad spectrum. This is not
15 surprising given the range of inputs and techniques employed and unprecedented market
16 conditions. All methods are not, however, providing a reasonable estimate for HQD's and
17 HQT's cost of equity at this time. As the Régie has confirmed in the past, consistent with
18 the *Hope* decision, it is the end result and not the method that is determinative of a fair
19 return.

20 Based on the results of the analyses discussed above and throughout our testimony, the
21 ability of the CAPM to produce reliable results is questionable in light of the factors
22 affecting the inputs at this time. Bond yields in Canada and the U.S. have been driven to all-

1 time lows, and most would agree below sustainable levels in the longer term. As a result of
2 the financial crisis and recession, utility betas have also been impacted, and market risk
3 premium estimates cover a broad spectrum. There is a substantial gap between historic
4 equity returns and the higher returns implied in current stock market data. These are
5 problems with the CAPM, and in general, in the current market environment.

6 As shown in Table 11 and described in the CAPM section, we reconcile for these differences
7 using logic employed by the Régie in the past. We begin with a Canadian risk free rate. The
8 Market Risk Premium is a combination of both Canadian and U.S. market inputs, including
9 both historic and forward-looking estimates. The beta is derived from the U.S. electric
10 utility proxy group, based on evidence showing that a carefully selected U.S. proxy group is
11 more representative of HQD and HQT than the Canadian companies; therefore, the beta
12 from the U.S. companies is more representative. Floatation costs are included consistent
13 with the Régie's past decisions, and finally, a 75 basis point adjustment is made for
14 differences between the CAPM results and the DCF models. This reconciliation is
15 consistent with the Régie's approach factoring in "Adjustment for the Result of Other
16 Models" in the 2012 Gaz Métro rate case. The reconciled CAPM result of 9.22 percent
17 offers a view into the required adjustment to inputs to achieve a reasonable result in the
18 current environment.

19 Under current market conditions, Concentric believes greater weight should be given to the
20 DCF model. The average of the DCF method for the U.S. electric utility proxy group
21 produces a relatively tight range of 9.20 percent to 9.58 percent, with an average of 9.41
22 percent. The Canadian DCF produces a range of 9.38 percent to 12.05 percent, averaging

1 10.71 percent. Placing more weight on the analytical results produced by the DCF model
2 with U.S. proxy companies and selecting the lower end of the range due to the lack of
3 generation risk (even though we have not made any offsetting adjustment for higher
4 financial risk), the estimated cost of equity for HQD and HQT is 9.2 percent. This
5 recommended ROE is supported by the range of analytical results produced by DCF
6 analyses for both the Canadian proxy group and the U.S. electric utility proxy group, and can
7 be reconciled with the CAPM with appropriate adjustments.

8 Application of the traditional CAPM formula, not including flotation costs, to the Canadian
9 proxy group would produce a 7.81 percent ROE. This return would not be within the
10 reasonable range of ROE estimates, and in Concentric's view would not meet the measures
11 of a fair return. In addition, it would not be consistent with the stand-alone principle, which
12 requires the allowed ROE for HQD and HQT to be set at a level as if the companies were
13 independently going to the equity markets to raise capital.

14 **Q. Does this conclude your pre-filed Direct Testimony?**

15 **A.** Yes, it does.

APPENDIX A: BUSINESS RISK ANALYSIS

Q. Please describe how your business risk analysis is organized.

A. Each section of the risk analysis begins with a discussion of the particular business risk for HQD and HQT and then examines the relative situation for the Canadian and U.S. proxy group companies. The results of Concentric's business risk analysis are summarized on Exhibit JMC-4, Schedules 1-7. The percentages on that exhibit are weighted based on the number of customers at each operating company. In Concentric's view, that is a fair and reasonable representation of the percentage of utility revenues and costs that are protected against a specific business risk. Among the U.S. electric utility proxy group, Concentric excluded any operating companies that accounted for less than 10 percent of the total distribution customers of the parent company (e.g., the risk analysis was performed for Northern States Power – Minnesota in the State of Minnesota, but not in South Dakota), any operating companies that provided service within the same jurisdiction as a larger entity (e.g., the risk analysis was performed for Consolidated Edison of New York, but not for Orange and Rockland, both of which provide service in the State of New York), and any operating companies that provide regulated natural gas distribution service.

(1) Ownership of Regulated Generation

Q. Please discuss your analysis of the business risk associated with owning regulated generation.

A. Concentric examined the effect that owning regulated generation has on the business risk of the Canadian and U.S. electric utility proxy group companies relative to HQD and HQT. In that regard, HQD owns very limited diesel generation in remote communities, but it is

1 essentially a pure-play distribution company. HQT does not own generation and is a pure-
2 play transmission company. Among the operating companies in the Canadian proxy group,
3 Nova Scotia Power is the only electric utility that owns significant regulated generation,
4 while FortisBC Electric and Newfoundland Power own limited generation. In summary, as
5 shown on Exhibit JMC-4, Schedule 1, 13 percent of the operating companies in the
6 Canadian proxy group (based on number of customers) own regulated generation, and an
7 additional 11 percent of those companies own limited generation, such as renewable
8 resources like solar, wind, and biomass.

9 By comparison, as also shown on Exhibit JMC-4, Schedule 1, 70 percent of the operating
10 utilities in the U.S. proxy group (based on number of customers) own regulated generation,
11 while 18 percent own limited regulated generation, and the remaining 12 percent do not own
12 regulated generation. On this factor, many operating companies in the U.S. electric utility
13 proxy group have more business risk than HQD because they retain the generation function.
14 As discussed in Section VIII of the testimony, from 2004-2012, integrated electric utilities in
15 the U.S. were awarded an ROE approximately 40 basis points higher than transmission and
16 distribution utilities. As also discussed in Section VIII of the testimony, Concentric has
17 determined that the higher business risk of the U.S. electric utility proxy group due to
18 ownership of regulated generation is more than offset by the lower financial risk of the U.S.
19 proxy group. We note that the FERC relies on proxy groups containing both T&D and
20 vertically-integrated electric utilities for the purpose of setting allowed ROEs for electric
21 transmission, without any risk adjustment for generation. Consequently, Concentric does
22 not believe that an adjustment to the U.S. results for ownership of regulated generation is
23 necessary.

1 (2) Fuel and Purchased Power Cost Risk

2 **Q. Please discuss the risk associated with fuel and purchased power costs.**

3 A. Fuel and purchased power costs represent approximately 50 to 65 percent of total operating
4 expenses for a typical electric distribution utility. For that reason, equity investors and credit
5 rating agencies are focused on whether the utility has any risk associated with recovery of
6 those costs. According to Moody's, "both the magnitude and volatility of these costs make
7 fuel adjustment clauses one of the more widely used and effective cost recovery mechanisms
8 in the industry."¹³⁰ For electric utilities that no longer own generation assets after the
9 deregulation of electricity markets, Moody's observes that fuel adjustment clauses, which
10 include purchased power costs, have become critical because many of these companies are
11 responsible for procuring power for their retail customers as part of their "Provider of Last
12 Resort" obligations, and therefore are responsible for procuring their generation
13 requirements in the wholesale power market.¹³¹

14 HQD purchases approximately 97 percent¹³² of its power from the Heritage Pool supplied
15 by Hydro Québec Production ("HQP") at a fixed price per kilowatt hour set by the Québec
16 government, while the remaining three percent of the energy supply is obtained primarily
17 from long-term contracts. As such, HQD faces price fluctuations for approximately three
18 percent of its electricity supply. HQD does not have an automatic fuel adjustment
19 mechanism; any changes in purchased power costs are recovered through the Company's

¹³⁰ "Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality: Evaluating a Utility's Ability to Recover Costs and Earn Returns," Moody's Investors Service, June 18, 2010, at p. 7.

¹³¹ Ibid.

¹³² Source: Hydro Quebec Annual Report 2011. Total electricity sales in 2011 were 170 TWh, and HQD purchased 165 TWh of electricity from HQP.

1 annual rate case filing. Any difference between actual and forecasted purchased power costs
2 is deferred and recovered through a cost variance account.

3 Nova Scotia Power is the only company in the Canadian proxy group that owns significant
4 regulated generation; it has an annual fuel adjustment mechanism that includes an incentive
5 component whereby Nova Scotia Power retains or absorbs ten percent of the over- or
6 under-recovered amount up to a maximum of \$5 million. Both gas distribution utilities
7 (Enbridge Gas Distribution and Gaz Métro) have purchased gas adjustment (“PGA”)
8 mechanisms that allow them to pass through the cost of natural gas. Similarly, all of the
9 operating utilities in the U.S. electric utility proxy group have fuel cost recovery mechanisms
10 that allow them to pass through fuel and purchased power costs to customers, where
11 applicable. As such, the operating companies in the Canadian and U.S. proxy groups are not
12 at risk for differences between the projected and actual cost of fuel with the exception of
13 those electric utilities in Wisconsin which are exposed to risk for two percent of fuel costs¹³³
14 and Nova Scotia Power, which has cost recovery risk for ten percent of its fuel and
15 purchased power costs. While HQD has more protection with respect to the price stability
16 of its electricity supply, the Canadian and U.S. proxy group companies have protection with
17 regard to recovery of fuel or purchased power costs.

18 Concentric also examined the frequency of the fuel cost recovery mechanisms in order to
19 determine whether certain companies have more timely recovery of changes in fuel supply
20 costs. In its risk assessment of the utilities sector, DBRS differentiates its ranking on energy

¹³³ The Wisconsin Public Service Commission adopted new fuel cost rules that became effective January 1, 2011. Under these new rules, electric utilities forecast fuel and purchased power costs, which are included in base rates. Any variations from the forecast are deferred for future recovery, with the exception of +/- 2%, which is retained or absorbed by the utility.

1 cost recovery, in part, based on how often the utility is allowed to adjust fuel costs in retail
2 rates, as well as whether the adjustment is automatic or subject to regulatory review.¹³⁴

3 As noted above, HQD does not have an automatic adjustment mechanism for purchased
4 power costs so the Company recovers any changes in those costs through its annual rate
5 case filing. As shown on Exhibit JMC-4, Schedule 2, among the operating companies in the
6 Canadian proxy group, Nova Scotia Power has an annual fuel cost recovery mechanism,
7 while Enbridge Gas Distribution has a quarterly PGA mechanism and Gaz Métro has a
8 monthly PGA mechanism. The other electric operating companies in the Canadian proxy
9 group are not responsible for the generation function. Among the operating companies in
10 the U.S. electric utility proxy group that have fuel cost recovery risk, approximately 44
11 percent (based on number of customers) are allowed to adjust fuel and purchased power
12 costs at least twice each year, while 56 percent have annual or “periodic” adjustment
13 mechanisms.

14 Since HQD has little risk associated with variations in fuel or purchased power costs, and
15 since many of the operating companies in the Canadian and U.S. proxy groups are allowed
16 to adjust for changes in fuel costs on at least a semi-annual basis, Concentric concludes that
17 investors do not perceive any material difference between HQD and the operating
18 companies in the Canadian and U.S. proxy groups in terms of the frequency of fuel cost
19 recovery adjustments.

20 (3) Volume/Demand Risk

¹³⁴ Dominion Bond Rating Service, “Assessing Regulatory Risks in the Utility Sector,” May 2012, at p. 7.

1 **Q. Please discuss the risks associated with changes in customer demand as compared**
2 **to test year volume for electric distribution companies.**

3 A. The primary business risk associated with changes in customer demand is that rates are set
4 under the assumption that customers will purchase a certain volume of electricity during the
5 test year. To the extent the customer's actual usage is different than forecasted demand, the
6 utility may be unable to earn its allowed return, especially if a large percentage of its fixed
7 costs are recovered through volumetric charges. There are many different sources of risk
8 related to changes in demand/volume, including: (1) weather conditions; (2) economic
9 conditions; (3) electricity prices; and (4) energy efficiency and conservation programs.

10 Several Canadian regulators have mitigated volume/demand risk attributable to weather
11 variations by approving variance accounts to allow the utility to recover the difference
12 between forecast and actual demand. HQD has a weather-related variance account, as does
13 Newfoundland Power and Gaz Métro. None of these weather variance accounts, however,
14 take into consideration changes in demand that are caused by economic conditions,
15 electricity prices, or energy efficiency and conservation programs. In those circumstances,
16 regulators in both the U.S. and Canada have addressed volumetric risk in a variety of ways,
17 including (1) revenue decoupling mechanisms ("RDM"), which break the link between
18 volume and fixed cost recovery whether the change in demand is caused by weather,
19 economic conditions, or energy efficiency and conservation programs, (2) lost revenue
20 adjustment mechanisms ("LRAM"), which allow the utility to recover revenues that were
21 lost due to conservation and energy efficiency programs, and (3) formula rate plans (also
22 known as rate stabilization plans), which allow the utility to adjust rates annually up to a
23 specified percentage if it did not earn its authorized return.

1 As shown on Exhibit JMC-4, Schedule 3, approximately 62 percent (based on the number of
2 customers) of the operating companies in the Canadian proxy group have RDMs or LRAMs,
3 and 11 percent have weather normalization adjustment clauses or variance accounts that
4 protect against volume/demand risk. Among the operating companies in the U.S. electric
5 utility proxy group, approximately 26 percent are protected against volumetric risk through
6 RDMs or formula rate plans that adjust rates annually to account for changes in
7 volume/demand, and 18 percent have weather normalization adjustment clauses that protect
8 against volume/demand risk. In summary, HQD has somewhat less protection against
9 changes in volume/demand than the operating companies in the Canadian proxy group,
10 most of which have broader protection against volume risk through RDMs or LRAMs than
11 HQD, which only has a weather variance account. Similarly, HQD has somewhat less
12 protection against volume risk than the operating companies in the U.S. electric utility proxy
13 group, approximately 44 percent of which have RDMs or operate under formula rate plans,
14 or have weather normalization adjustment clauses.

15 **Q. Did Concentric also consider the risk associated with changes in demand/volume**
16 **for electric transmission companies?**

17 A. Yes. HQT is not exposed to risks associated with changes in demand. Specifically, HQT's
18 transmission revenue requirement is allocated to native load and point-to-point service on
19 the basis of their total capacity needs. HQT provides capacity to native load at a price that is
20 fixed at the beginning of the year, based on HQD's peak demand for that year. Residual
21 capacity becomes available to other transmission customers. Most of HQT's transmission
22 capacity available for point-to-point service is contracted via long-term agreements, and
23 point-to-point customers must pay for the capacity they reserve whether they use it or not.

1 HQD pays HQT a fixed monthly demand charge equal to one twelfth of HQT's annual
2 revenue requirement for native-load transmission service. In 2007, the Régie established a
3 new variance account corresponding to the difference between revenue forecasts for point-
4 to-point transmission services recognized by the Régie for rate-setting purposes and actual
5 point-to-point transmission service revenue.

6 Other transmission companies in the Canadian proxy group also have little risk with respect
7 to fluctuations in demand. For example, ATCO Electric Transmission collects its approved
8 revenue requirement from the Alberta Electric System Operator in twelve equal monthly
9 installments, and thus is not dependent on the price or volume of electricity transmitted
10 through its system. Among government-owned transmission companies in Canada, Hydro
11 One Networks has congestion pricing of transmission rather than a "take-or-pay"
12 arrangement like HQT. Under this pricing arrangement, Hydro One Networks has slightly
13 more risk associated with its transmission operations than HQT. The OEB approves Hydro
14 One Networks' transmission and distribution rates based on projected electricity load and
15 consumption levels. If actual load or consumption falls below projected levels, the
16 company's rate of return for either, or both, of these businesses could be materially adversely
17 affected.

18 Among companies in the U.S. proxy group, some are located within a region with an
19 Independent System Operator ("ISO") or Regional Transmission Operator ("RTO"), while
20 others are not. In regions with ISOs or RTOs, the cost of transmission service over the
21 pool transmission facilities (usually classified at 115kW or above) is based on the revenue
22 requirements of the transmission owners in the region. To determine the transmission

1 service rate, each transmission owner must calculate its annual revenue requirement for its
2 eligible facilities pursuant to a revenue requirement formula contained in the ISO or RTO
3 Tariff. This formula generally includes the operation and maintenance costs associated with
4 the eligible facilities, as well as a return on rate base. Every year, each transmission owner
5 populates this pro-forma formula with its own company-specific costs for the year. These
6 individual revenue requirements are then aggregated by the ISO into a single revenue
7 requirement and divided by a similarly aggregated monthly coincident peak demand in order
8 to calculate the transmission service rate. Because the transmission owners can neither over-
9 recover nor under-recover their costs, they must “true-up” their previous year’s revenue
10 requirement, if necessary, to reflect any over or under collections from the previous year. In
11 this way, they are not exposed to demand risk since they are guaranteed full cost recovery.

12 In regions without an ISO or RTO, the calculation of the transmission revenue requirement
13 is the same, with the only difference between regions being who collects the revenues. In
14 these non-ISO/RTO regions, each transmission owner calculates its own transmission
15 service rate based on its costs and its demand forecast in its service territory. Each
16 transmission owner also collects the transmission service revenues from the customers using
17 its transmission system. These customers must pay the applicable transmission rate over the
18 system(s) they are using to service their customer load. Similar to the ISO/RTO regions, the
19 transmission owners in non-ISO/RTO regions are guaranteed full cost recovery and update
20 their transmission rate each year to reflect any over or under recovery from the previous
21 year. As a result, these transmission owners are not exposed to demand risk.

22 (4) Capital Cost Recovery Risk

1 **Q. Please explain the risk associated with capital cost recovery.**

2 A. Capital spending is a two-edged sword for utilities. On the one hand, capital spending
3 supports dividend growth and share price appreciation; on the other, it can increase the need
4 for external financing and place pressure on cash flows and credit metrics without ongoing
5 accommodation in rates for system expansion. Capital cost recovery has been identified by
6 credit rating agencies as a significant business and regulatory risk. For example, in discussing
7 the importance of cost recovery provisions to credit quality for utilities, Moody's states:

8 The utilities industry is in the midst of a substantial capital expenditure
9 program, with significant investment planned in all aspects of its business,
10 including generation, transmission, and distribution, as well as for substantial
11 environmental compliance expenditures. Because of the size and complexity
12 of many of these projects, Moody's places a high degree of emphasis on the
13 regulatory certainty for the recovery of such costs, which is critical for the
14 maintenance of utility credit quality. For some of these projects, especially
15 when considering added uncertainty related to the economy and the timing
16 of future laws and regulation related to carbon, it will be viewed as a
17 significant credit positive if utilities are able to obtain regulatory support for
18 recovery in advance. This would serve to limit regulatory risk associated with
19 eventual disallowance or nonrecovery of already expended costs.¹³⁵

20 **Q. What are the different ways that utility regulators have reduced the risk of capital**
21 **cost recovery?**

22 A. Utility regulators have reduced the risk of capital cost recovery in the following ways: (1)
23 pre-approval of capital budgets or major capital construction projects; (2) allowing the utility
24 to earn a cash return on Construction Work in Progress ("CWIP"); and (3) approving cost
25 tracking mechanisms that allow the utility to recover capital costs for replacing aging
26 infrastructure.

¹³⁵ "Cost Recovery Provisions Key to Investor Owned Utility Rating and Credit Quality: Evaluating a Utility's Ability to Recover Costs and Earn Returns," Moody's Investors Service, June 18, 2010, at p. 8.

1 **Q. Are HQD and HQT granted pre-approval of capital budgets or major capital**
2 **construction projects?**

3 A. Yes. The Régie annually approves the capital budget for smaller projects on a dollar amount
4 basis and approves individual major projects with an estimated cost in excess of \$25 million
5 for HQT and \$10 million for HQD. Projects within that approved capital budget are
6 included in HQT's and HQD's forecasted test year and added to rate base for cost recovery
7 if they are expected to be commissioned into service that year. While pre-approval of
8 construction projects allows HQT and HQD to recover capital costs once the plant is placed
9 in service, it does not allow them to earn a cash return on the project during construction.

10 As shown on Exhibit JMC-4, Schedule 4, 22 percent of the operating companies (based on
11 number of customers) in the Canadian proxy group receive pre-approval for specific capital
12 projects, while 68 percent of the operating companies in the U.S. electric utility proxy group
13 may request Commission pre-approval of construction costs.

14 **Q. Why do equity investors and credit rating agencies prefer utilities that are allowed to**
15 **earn a cash return on CWIP rather than AFUDC?**

16 A. Investors may be concerned that (1) multiple capital projects will place pressure on the
17 company's cash flows and credit metrics during construction, (2) any project delays will
18 further postpone cost recovery, and (3) some portion of costs in excess of any pre-approved
19 amounts may be deemed imprudent. For example, Moody's states:

20 Similarly, the inclusion of CWIP in rate base provides greater regulatory
21 certainty, reduces the chance of rate shock or regulatory disallowance at the
22 end of the construction period, and helps moderate financial pressure on a
23 utility during a capital build cycle. Some of these concepts require a
24 significant departure from the mindset of traditional rate regulation, where

1 costs are typically recovered in rates only after a project is completed and
2 placed into service.¹³⁶

3 Therefore, from an investment and cash flow perspective, the opportunity to earn a cash
4 return on CWIP is favorable, especially for large capital projects that are not expected to be
5 completed for several years because it (1) provides more immediate cost recovery, (2)
6 reduces pressure on cash flows and credit profiles during construction, and (3) reduces
7 concerns about rate shock. This regulatory treatment is consistent with annual rate cases
8 that allow a return on assets under construction but not yet in service. The alternative
9 approach is Allowance for Funds Used During Construction (“AFUDC”), where the full
10 return is delayed until the plant is placed in service. The book earnings under AFUDC are
11 comparable to those with CWIP or annual rate cases, but a utility with AFUDC has reduced
12 cash flows and lower financial integrity during construction, which increases uncertainty for
13 investors and potentially raises the cost of future borrowings.

14 As shown on Exhibit JMC-4, Schedule 4, ATCO Electric Transmission is the only operating
15 company in the Canadian proxy group that has been allowed to place CWIP in rate base for
16 transmission projects directly assigned from the AESO.¹³⁷ Enbridge Gas Distribution has
17 the possibility to earn a cash return on CWIP, although there is no evidence that it has
18 requested approval to place CWIP in rate base. By comparison, 45 percent of the operating
19 companies (based on number of customers) in the U.S. electric utility proxy group have
20 received approval to place CWIP in rate base for major capital projects during construction.

¹³⁶ Ibid., at p. 2.

¹³⁷ Alberta Utilities Commission, ATCO Electric Ltd, 2011-2012 Phase I Distribution Tariff and 2011-2012 Transmission Facility Owner Tariff, Decision 2011-134, April 13, 2011, at pp. 10-11.

1 **Q. Why are capital cost tracking mechanisms important to utilities, customers and**
2 **investors?**

3 A. Another important aspect of capital cost recovery for electric distribution and transmission
4 utilities is related to the repair and replacement of aging infrastructure, and compliance with
5 environmental regulations, energy efficiency requirements, and renewable portfolio
6 standards.¹³⁸ In response, some regulators have allowed electric utilities to implement cost
7 tracking mechanisms or rate riders to recover the costs associated with these investments
8 over a specified period of time.

9 HQD and HQT do not have capital cost tracking mechanisms. Rather, both units are
10 allowed to recover costs of projects related to replacement or repair of aging infrastructure,
11 compliance with environmental regulations, and improvement of service quality through the
12 traditional regulatory process. The cost of these projects, if they are expected to be
13 commissioned into service in that year, is added to rate base for recovery through
14 transmission and distribution rates. As shown on Exhibit JMC-4, Schedule 4, among
15 operating companies in the Canadian proxy group, 76 percent are allowed to recover these
16 types of capital costs through either variance/deferral accounts or cost tracking mechanisms,
17 while 64 percent of the operating companies in the U.S. electric utility proxy group have
18 capital cost trackers or rate riders for purposes of recovering these types of capital
19 investments.

¹³⁸ Although Québec has not implemented renewable portfolio standards, mostly because of Hydro-Québec's major hydro-electric renewable source of energy, this is an important consideration in other Canadian provinces and U.S. states which have implemented these standards.

1 **Q. What are your conclusions regarding capital cost recovery for HQD and HQT**
2 **relative to the Canadian and U.S. proxy groups?**

3 A. Based on Concentric's research and analysis, our view is that HQD and HQT generally have
4 comparable risk mitigation for capital cost recovery as the Canadian proxy group because
5 regulated utilities in Canada file rate cases on a more frequent basis, meaning that utility
6 companies are able to include capital investments in rate base once they are placed into
7 service and start earning a return on those investments without significant regulatory lag. In
8 addition, HQD and HQT receive pre-approval of capital expenditures (including specific
9 approval for major projects), whereas many of the Canadian utilities do not. With respect to
10 the operating companies in the U.S. electric utility proxy group, Concentric concludes that
11 even though those U.S. companies generally do not file rate cases as frequently as those in
12 Canada, they have similar or better risk protection on this factor as HQD or HQT through
13 either approval of CWIP in rate base while the plant is under construction, or
14 implementation of cost tracking mechanisms that provide accelerated recovery of capital
15 costs for replacing aging infrastructure.

16 (5) Rate Regulation and Earnings Sharing

17 **Q. Please describe the risk associated with how the utility recovers its revenue**
18 **requirement.**

19 A. Utilities traditionally recovered their revenue requirement by setting rates based on the
20 allowable expenses and the level of useful assets during the specified test year. In an effort
21 to provide utilities with an incentive to achieve operating efficiencies and cost savings, some
22 regulators have approved incentive regulation mechanisms ("IRM") or performance-based
23 regulation ("PBR") plans, many of which allow the utility to retain a percentage of any cost

savings achieved as long as the utility continues to meet service quality standards. Those IRMs, however, can create additional risk for the utility. In assessing regulatory risk for the utilities sector, DBRS recently indicated that it views cost-of-service regulation as lower risk than incentive regulation. In addition, DBRS considers the length of an incentive regulation period, and gives a higher score for a shorter IRM period.¹³⁹ Table 12 shows how DBRS assigns rankings based on the method of rate regulation (i.e., cost of service vs. incentive regulation).

Table 12: DBRS Ranking Criteria: Cost of Service vs. Incentive Regulation¹⁴⁰

Score	Item	Definition
Outstanding	Cost of Service	• COS regime allowing utilities to recover prudently and reasonably incurred operating costs • Capital expenditures are reviewed and approved by the regulator through an annual COS filing • There is a good mechanism for a utility to recover extraordinary operating costs
Excellent	IRM (3 years or shorter)	• IRM regime with maximum three years between COS years • Regulator sets a reasonable productivity factor • There is a reasonable mechanism to consider incremental capital expenditures
Very Good	IRM (4-5 year framework)	• The IRM period is four to five years • Regulator sets a reasonable productivity factor • There is a reasonable mechanism to consider incremental capital expenditures
Good	IRM (6-10 year framework)	• The IRM period is six to ten years • Regulator sets a reasonable productivity factor • There is a reasonable mechanism to consider incremental capital expenditures
Satisfactory	IRM (10+ years)	• The IRM period is over ten years • Regulator sets a reasonable productivity factor • There is a reasonable mechanism to consider incremental capital expenditures

¹³⁹ DBRS, “Assessing Regulatory Risk in the Utility Sector,” May 2012, at p. 8.

¹⁴⁰ Ibid.

1 Neither HQD nor HQT has historically operated under an IRM. Among the operating
2 utilities in the Canadian proxy group, Enbridge Gas Distribution operated under a five-year
3 IRM that expired on December 31, 2012, and plans to file a new IRM plan with the OEB
4 which would become effective for the 2014 rate year; ATCO Electric Distribution and Fortis
5 Alberta were scheduled to begin operating under an IRM on January 1, 2013, subject to
6 approval of compliance filings with the AUC; and Gaz Métro is currently in the midst of a
7 proceeding before the Régie that would establish a new IRM for the 2014 rate year, however,
8 the company will operate under cost-of-service regulation for the 2013 rate year. As shown
9 on Exhibit JMC-4, Schedule 5, 76 percent (based on number of customers) of the operating
10 companies in the Canadian proxy group are subject to an IRM with a multi-year rate plan,
11 while the remaining 24 percent are under traditional cost of service regulation. Among the
12 operating companies in the U.S. electric utility proxy group, 58 percent (based on number of
13 customers) are subject to an IRM (50 percent with a multi-year rate plan and eight percent
14 with formula rate plans) and 42 percent operate under traditional cost of service regulation.

15 Neither HQD nor HQT has historically been required to share over-earnings with
16 customers or allowed to recover under-earnings from customers. Among the operating
17 companies in the Canadian proxy group, Enbridge Gas Distribution and Newfoundland
18 Power are both required to share a percentage of earnings above their authorized return;
19 however, the recently-approved IRM for ATCO Electric Distribution and Fortis Alberta did
20 not include an earnings sharing component. As shown on Exhibit JMC-4, Schedule 5, 64
21 percent (based on number of customers) of the operating companies in the Canadian proxy

1 group and 58 percent of the operating companies in the U.S. electric utility proxy group have
2 an ESM, either as part of a multi-year rate plan or a formula rate plan.

3 If HQD and HQT were to begin operating under either an ESM or an IRM, any change in
4 business risk of the two companies would depend on the design and parameters of the
5 specific plan that is implemented. Important parameters would include (1) the term of the
6 plan, (2) the level of any productivity factor, (3) the provisions for recovering incremental
7 capital costs, and (4) whether any ESM was symmetric or asymmetric, the deadbands, and
8 the sharing percentages. In general, as observed by DBRS, any change from cost-of-service
9 regulation is considered an increase in risk for the utility. A reasonably balanced ESM should
10 not, however, materially impact the level of risk faced by HQD and HQT.

11 (6) Regulatory Lag

12 **Q. What is regulatory lag, and how does it affect the business risk of electric distribution**
13 **and transmission companies?**

14 A. Regulatory lag refers to the delay between the time when a utility incurs costs to serve its
15 customers and when it recovers those costs through rates. Regulatory lag differs by
16 jurisdiction based on the timing of test period data and the duration of the rate case process.
17 For example, absent offsetting growth in revenues or a reduction in other expenses, when a
18 utility places into service an infrastructure investment necessary for safe and reliable service
19 and that cost is not reflected in rate base until a subsequent rate case, there is regulatory lag
20 with a real cost in foregone earnings. Regulatory lag results in earnings attrition when a
21 utility's earnings systematically fall below authorized levels.

Q. How have you measured the risk associated with regulatory lag?

A. There are a variety of factors that influence the extent to which a utility is experiencing regulatory lag. Those factors include: (1) the test year convention; (2) the use of interim rates while a rate case is pending; and (3) rate case lag.

a) Test Year Convention

A forecasted test year gives a utility the ability to recover forecasted rather than historical expenses, thereby reducing regulatory lag and earnings attrition. The Régie uses a forecasted test year to set the revenue requirements for HQD and HQT; likewise, as shown on Exhibit JMC-4, Schedule 6, all of the operating companies in the Canadian proxy group and 82 percent of the operating companies (based on number of customers) in the U.S. electric utility proxy group operate in jurisdictions that use fully or partially forecasted test years, while 18 percent of operating companies in the U.S. electric utility proxy group use historical test years adjusted for known and measurable changes.

b) Interim Rates

Interim rates allow a utility to increase current rates to recover higher test year costs while a rate case is pending, subject generally to refund once final rates are adopted, whereas suspended rates maintain the currently effective rates until a new rate decision is issued. Some regulatory authorities approve interim rates on a routine basis, while other jurisdictions only approve interim rates when the utility can demonstrate that its financial integrity would be impaired without interim rates. HQD continues to charge the currently effective rates until the Régie issues final rates for the new rate year, whereas HQT applies interim rates, as approved by the Régie, subject to adjustment in customer invoices once final rates are

1 adopted. As shown on Exhibit JMC-4, Schedule 6, 29 percent of the operating companies in
2 the Canadian proxy group and 55 percent of the operating companies in the U.S. electric
3 utility proxy group operate in jurisdictions that allow interim rates under all circumstances,
4 while 37 percent of the operating companies in the U.S. proxy group are allowed to
5 implement interim rates in a financial emergency.¹⁴¹

6 **c) Rate Case Lag**

7 Rate case lag refers to the time between when a rate case is filed and when the decision is
8 issued. Rate case lag is important especially for utilities that use a historical test year because
9 it means that by the time new rates become effective, they may not be representative of the
10 utility's allowable expenses. In recent years, the time to complete a rate case has generally
11 been slightly more than one month longer for the Canadian operating companies, including
12 HQD and HQT, than for the companies in the U.S. proxy group (i.e., 9.9 months in Canada
13 and 8.7 months in the U.S.)

14 **Q. What is your conclusion concerning the effect of regulatory lag on HQD and HQT**
15 **compared to the Canadian and U.S. proxy groups?**

16 A. Based on this evidence, Concentric finds that HQD and HQT have comparable regulatory
17 protection with regard to the use of forecasted test years as the operating companies in the
18 Canadian proxy group, and slightly less risk than the companies in the U.S. electric utility
19 proxy group, where fully forecasted test years are less common. With respect to interim
20 rates, HQD has somewhat more risk than the operating companies in the Canadian proxy
21 group, and more risk than the operating companies in the U.S. electric utility proxy group,

¹⁴¹ These percentages do not include Enbridge Gas Distribution or Gaz Métro, both of which have been under incentive regulation plans, or Alabama Power and Mississippi Power, both of which are under formula rate plans.

1 the vast majority of which have the ability to request interim rates. HQT has somewhat less
2 risk than the operating companies in the Canadian proxy group and similar risk to the
3 operating companies in the U.S. electric utility proxy group on this factor. Finally, HQD
4 and HQT have similar risk to the Canadian proxy group in terms of rate case lag, and slightly
5 higher risk than the operating companies in the U.S. proxy group, which have somewhat
6 shorter times between the application and the rate decision.

7 (7) Cost Recovery Mechanisms

8 **Q. Please explain the risk associated with recovery of costs that tend to fluctuate**
9 **substantially from year to year compared with the amount recovered in rates.**

10 A. Cost recovery mechanisms are one of the most significant factors that determine whether a
11 utility is able to earn its authorized ROE. Concentric examined several categories of costs
12 that (1) tend to fluctuate substantially from year to year, (2) are significant in magnitude, and
13 (3) are generally beyond the control of utility management. Among those cost categories for
14 regulated utilities, Concentric considered the following: (1) pension expenses; (2) bad debt
15 expense; (3) storm cost recovery; (4) changes in interest rates; and (5) energy efficiency and
16 demand side management costs.

17 **Q. Have regulatory authorities in Canada and the U.S. used the same cost recovery**
18 **mechanisms for these types of costs?**

19 A. No, they have not. When there have been variations between actual costs and test year costs
20 in Canada, regulators have typically addressed these fluctuations through the approval of
21 variance accounts, which are designed to reduce the volatility in earnings and cash flows due
22 to fluctuations in costs and revenues. U.S. regulators have taken a slightly different

1 approach. Specifically, U.S. utility regulators have typically approved rate riders/surcharges
2 and cost tracking mechanisms to recover costs that tend to fluctuate. The rate
3 rider/surcharge is a temporary adjustment to the customer bill that raises or lowers rates for
4 a limited time by a specified amount. A cost tracking mechanism is an adjustment clause
5 that allows a utility's rates to fluctuate in response to changes in costs or conditions.
6 Regardless of the specific method regulators have chosen to mitigate the risk of cost
7 recovery, the end result is that the vast majority of utility companies in both Canada and the
8 U.S. have recovery mechanisms to protect them and their customers against significant
9 fluctuations in costs and events that are beyond the control of utility management.

10 **Q. Please discuss the results of your analysis of cost recovery mechanisms for HQD and**
11 **HQT and the Canadian and U.S. proxy groups.**

12 A. Exhibit JMC-4, Schedule 7, presents the cost recovery mechanisms that are in place at HQD
13 and HQT and the operating companies in the Canadian and U.S. proxy groups for the cost
14 categories identified above. Table 13 summarizes the percentage of operating companies
15 (based on number of customers) in the Canadian and U.S. proxy groups that has some form
16 of cost recovery mechanism for each of these costs.

Table 13: Cost Recovery Mechanisms

Cost	HQD	HQT	Canadian Proxy Group	U.S. Proxy Group
Pension expenses	Yes	Yes	69%	36%
Bad Debt expenses	No	No	5%	13%
Storm Cost Recovery	Limited ¹⁴²	No	0%	79%
Interest Rate Change	No	No	9%	17%
Energy Efficiency/DSM	No	N/A	81%	76%

Based on this analysis, Concentric concludes that, on balance, HQD and HQT have similar regulatory protections as the companies in the Canadian and U.S. proxy groups against specific categories of costs that tend to fluctuate significantly from year to year, are material in nature, and are beyond the control of utility management. As shown in Table 13, however, HQD and HQT have higher risk associated with storm cost recovery than the majority of operating companies in the U.S. proxy group, but more protection against variations in pension expenses.

(8) Longer Term Risks

Q. Did you consider any additional longer-term risks that differentiate HQD and HQT from the companies in the Canadian and U.S. proxy groups?

A. Yes, Concentric considered several additional factors. First, HQD faces more competitive risk due to its high concentration of industrial customers in Québec, which makes HQD more vulnerable to longer-term risks associated with an economic downturn that could

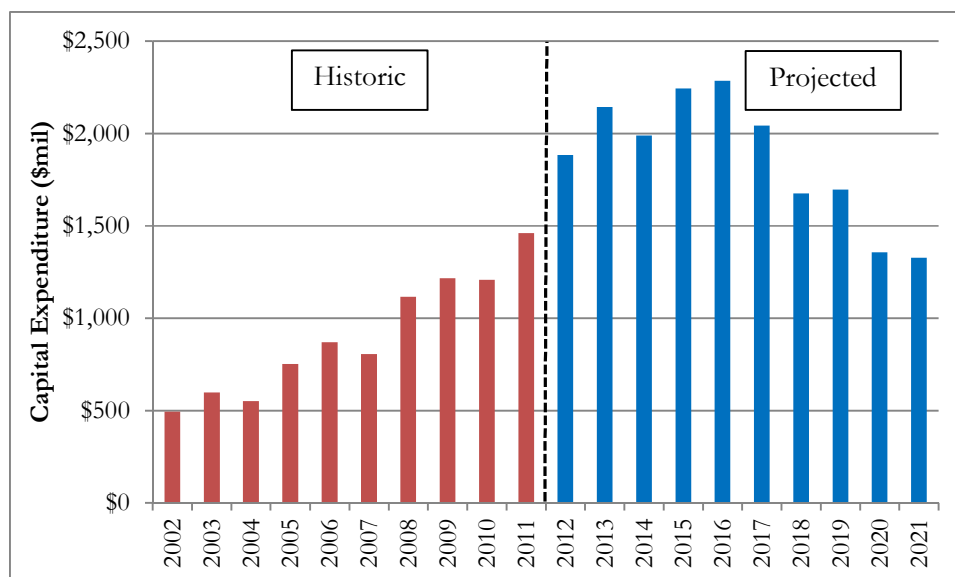
¹⁴² Pursuant to decision D-2009-016, HQD has a mechanism in place which allows the Company to recover a portion of operating costs related to a major breakdown. Specifically, HQD can take a provision in rates for up to \$8 million per year and has a variance account for operating costs that exceed \$16 million. HQD is at risk for any amounts between \$8 million and \$16 million related to operating costs from storm. The mechanism does not pertain to capital costs for assets that were damaged during the storm.

1 cause those industrial customers to reduce their demand for electricity, as well as economic
2 bypass or self-generation if the industrial customers determine those options are more
3 economical. As shown on Exhibit JMC-3, Schedule 2, approximately 31 percent of HQD's
4 2011 distribution revenues were derived from sales to industrial customers; this percentage is
5 considerably higher than the other electric distributors in the Canadian and U.S. proxy
6 groups with the exception of ATCO Electric Distribution at 36 percent.

7 Second, HQD has higher business risk than it did when the Régie issued its previous ROE
8 determination due to the relative competitiveness of electricity and natural gas in Québec.
9 This is especially important for HQD because of the number of residential and commercial
10 customers in Québec that use electricity for heating. As the price of natural gas has declined
11 over the past few years, that fuel source has become more competitive with the low price of
12 electricity in Québec.

13 Third, HQT is in the midst of a significant capital spending program under which it will
14 spend approximately \$17 billion over the next nine years (2013-2021) for growth response
15 and to upgrade existing infrastructure and replace aging transmission lines and equipment.
16 As shown on Chart 6, the annual projected capital spending from 2013-2017 for HQT is
17 substantially higher than historical levels from 2002-2011. Specifically, annual capital
18 spending for HQT from 2013-2017 is projected at \$2,140.7 million compared with historical
19 annual capital spending from 2002-2011 of \$906.3 million. This represents an increase of
20 136 percent.

Chart 6: Historic and Projected Capital Spending for HQT



HQT's capital spending requirements will require continued access to capital markets at reasonable terms in order to maintain the financial integrity and the credit metrics of the Company during this period. Timely cost recovery of these capital expenditures represents a substantial business and financial risk for HQT over the next ten years.

APPENDIX B: FINANCIAL RISK ANALYSIS

Q. Please compare the financial risk of Canadian and U.S. utilities generally.

A. In general, regulators in Canada have tended to approve lower deemed equity ratios for regulated utilities than in the U.S. Concentric believes this practice has evolved for two principal reasons: (1) there is a history of government ownership of utilities in Canada particularly in the electric sector, and similar to municipal and state-owned utilities in the U.S., these utilities enjoy explicit or implicit government support, enabling higher debt ratios; and (2) Canadian regulators deem utility debt ratios with a focus on the minimum requirements for investment grade credit standards. Regulators in the U.S. more typically assess the reasonableness of capital structure based on a combination of credit metrics and reference to the proxy group range to test comparability. Regulated utilities in Canada generally have higher financial leverage than those in the U.S., and therefore more financial risk on a stand-alone basis.

Q. What are HQD's and HQT's current deemed equity ratios?

A. The current deemed equity ratios for HQD and HQT are 35.0 percent and 30.0 percent, respectively.

Q. Please compare the financial risk of HQD and HQT to the companies in the Canadian proxy group.

A. As shown in Table 14, the average deemed equity ratio in 2012 of the Canadian companies included in Concentric's risk analysis was 39.3 percent. The lowest deemed equity ratio for an electric transmission company was 37 percent (ATCO Electric Transmission), which is seven percent higher than HQT. Similarly, the lowest deemed equity ratio for an electric

distribution company was 39 percent (ATCO Electric Distribution), which is four percent higher than HQD.

Table 14: Canadian Proxy Group Deemed Common Equity Ratio

Company	Common Equity Ratio
ATCO Electric Distribution	39.00%
ATCO Electric Transmission	37.00%
Nova Scotia Power Inc.	37.50%
Enbridge Gas Distribution	36.00%
Fortis Alberta	41.00%
Fortis BC Power	40.00%
Newfoundland Power	44.69%
Gaz Métro	38.50%
TransCanada Pipelines	40.00%
Mean	39.30%

Q. How do HQD's and HQT's equity ratios compare to the average equity ratio for the U.S. electric utility proxy group?

A. The most notable risk difference between HQD and HQT and the operating utilities in the U.S. electric utility proxy group is the percentage of debt in the capital structure. As shown in Table 15, the U.S. electric utility proxy group average authorized common equity ratio is 50.2 percent, which is 15.2 percent higher than HQD's current deemed equity ratio of 35.0 percent, and 20.2 percent higher than HQT's current deemed equity ratio of 30.0 percent.

Table 15: U.S. Electric Utility Proxy Group
Average Authorized Common Equity Ratio¹⁴³

Company	Authorized Common Equity Ratio
ConEdison of New York	48.00%
Florida Power and Light	N/A
Connecticut Light and Power	49.20%
NSTAR Electric	N/A
Public Service of New Hampshire	52.40%
Western Mass Electric	50.70%
Alabama Power	N/A
Georgia Power	N/A
Gulf Power	38.50%
Mississippi Power	N/A
Wisconsin Electric	52.09%
NSP – Minnesota	52.56%
NSP – Wisconsin	52.37%
Public Service of Colorado	56.00%
Southwestern Public Service - TX	N/A
Mean	50.20%

Q. How does the capital structure affect the cost of equity?

A. The capital structure relates to a company's financial risk, which represents the risk that a company may not have adequate cash flows to meet its financial obligations, and is a function of the percentage of debt (or financial leverage) in the capital structure. In that regard, as the percentage of debt and preferred equity in the capital structure increases, so do the fixed obligations for the repayment of that debt. Consequently, as the degree of financial

¹⁴³ For utilities with operations in multiple jurisdictions, the authorized equity ratios shown are those for the jurisdiction in which the utility predominantly operates. Those utilities marked "N/A" did not have an authorized common equity ratio in their most recent rate case decision. In most instances those cases were resolved through a settlement agreement that did not specify the authorized equity ratio.

1 leverage increases, the risk of financial distress for common equity holders (i.e., financial
2 risk) also increases.¹⁴⁴ Since the capital structure can affect the subject company's overall
3 level of risk, it is an important consideration in establishing a fair return.

4 **Q. How do HQD's and HQT's capital structure impact their ability to raise capital on**
5 **reasonable terms?**

6 A. While the Canadian regulators' approach to capital structure may seek to reduce the
7 weighted-average cost of capital (due to more debt in the capital structure), it may also place
8 downward pressure on credit metrics. This could potentially raise the cost of debt, which
9 ultimately flows through to rate payers in the form of higher rates, and limit the financial
10 flexibility of the utility. Further, if more debt is deemed than that of comparable risk
11 utilities, the cost of equity must increase to compensate investors for that additional risk.
12 We note that HQD and HQT benefit from a government debt guarantee, but capital
13 structure should be considered on a stand-alone basis in order to send the proper price
14 signals, and avoid cross-subsidization between Québec's citizens and its electric consumers.

15 **Q. Other than the percentage of financial leverage in the capital structure, what other**
16 **ways do investors measure financial risk?**

17 A. Financial risk may also be measured through other credit metrics, such as the ratio of Funds
18 From Operations ("FFO") to debt, as well as the interest coverage ratios that compare
19 Earnings Before Interest and Taxes ("EBIT") and FFO to interest payments on long-term
20 debt.

¹⁴⁴ See Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at pp. 45-46.

1 **Q. How do HQD's and HQT's credit metrics in 2011 compare to the companies in the**
2 **Canadian and U.S. proxy groups?**

3 A. As shown on Exhibit JMC-5, the credit metrics for HQD and HQT in 2011 were much
4 weaker than for the companies in the Canadian and U.S. proxy groups. Specifically, HQD
5 and HQT have a higher debt to capital ratio, weaker interest coverage ratios, a weaker cash
6 flow to debt ratio, and higher debt to EBITDA ratios than the averages for both the
7 Canadian and U.S. proxy group.

8 **Q. What other factors affect the financial risk and credit metrics of HQD and HQT?**

9 A. HQD and HQT do not issue their own debt and do not have their own credit ratings.
10 Rather, the debt is issued by Hydro-Québec, and the credit rating is the same as that
11 assigned to the Province of Québec. The credit metrics shown on Exhibit JMC-5 indicate
12 that the allowed ROEs and deemed equity ratios for HQD and HQT, respectively, are not
13 sufficient to support Hydro-Québec's current A+ rating from S&P or Aa2 rating from
14 Moody's without the government debt guarantee. This supports the need for a higher ROE
15 for HQD and HQT in order to maintain the financial integrity of the utility on a stand-alone
16 basis. Absent a higher ROE, Hydro-Québec's credit metrics do not support the current
17 rating and could ultimately cause an increase to the cost for the government debt guarantee.

18 **Q. What would be the effect on HQD's and HQT's credit metrics if they were to begin**
19 **operating under an ESM?**

20 A. If HQD and HQT were to begin operating under an ESM, the credit metrics for those two
21 entities would be lower than they have been in the past few years. For example, if HQD and

HQT had only earned their allowed ROE in 2011, their credit metrics would have been weaker as shown on Table 16.

Table 16: Credit Metrics for HQD and HQT at Earned ROE

Utility	Debt to Capital Ratio	EBIT to Interest Coverage	FFO to Interest Coverage	FFO/Debt Ratio	Debt to EBITDA
HQD - Actual	65%	1.88	3.46	0.24	3.98
HQD - Adjusted	65%	1.66	3.24	0.23	4.24
HQT – Actual	70%	1.62	2.66	0.19	5.20
HQT - Adjusted	70%	1.53	2.58	0.18	5.37

This suggests that, in order to maintain the financial integrity of HQD and HQT under an ESM, it would be necessary to allow a higher ROE and/or a higher deemed equity ratio so that HQD and HQT would be able to maintain credit metrics on a going-forward basis consistent with the assigned rating.

Q. Has Concentric calculated what the projected credit metrics would be for HQD and HQT if the Régie were to accept the recommended ROE of 9.20% for both units?

A. Yes. The projected credit metrics for HQD and HQT with an ROE of 9.20% are shown in Table 17.

Table 17: Projected Credit Metrics for HQD and HQT at 9.20% ROE

Utility	Debt to Capital Ratio	EBIT to Interest Coverage	FFO to Interest Coverage	FFO/Debt Ratio	Debt to EBITDA
HQD - Actual	65%	1.88	3.46	0.24	3.98
HQD – Projected	65%	1.81	3.38	0.24	4.07
HQT – Actual	70%	1.62	2.66	0.19	5.20
HQT - Projected	70%	1.66	2.70	0.19	5.13

These projected metrics demonstrate that raising the allowed ROE for HQD and HQT to 9.20 percent would be directionally beneficial, but would not alleviate concerns that the credit metrics are not adequate to support the assigned credit rating, absent the government debt guarantee.

2011 % Regulated Operating Income and Revenues

Utility	% Operating Income	% Revenues
Consolidated Edison	98%	88%
Northeast Utilities	101%	99%
NextEra Energy	64%	69%
Southern Co.	93%	95%
Wisconsin Energy	61%	99%
Xcel Energy	100%	99%
U.S. Proxy Group Average	86%	92%

Utility	% Operating Income	% Revenues
Canadian Utilities Ltd.	60%	56%
Emera, Inc.	94%	92%
Enbridge Inc. (1)	22%	13%
Fortis Inc.	91%	93%
TransCanada Corp. (2)	0%	0%
Valener	98%	97%
Canadian Proxy Group Average	61%	59%

Note: Percentage of operating income may exceed 100% due to losses at affiliates.

(1) Does not include operating income or revenues from gas transmission.

(2) TransCanada has no income or revenues from regulated utility service. Gas transmission income and revenue was not considered in our analysis.

Canadian & U.S. Macroeconomic Factors

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[11]	[12]	[13]	[14]
	Total Return on:		Total Return on:		Real GDP Growth		CPI		10-year Gov't Bond		Exports		Unemployment		Currency
	S&P/TSX	S&P 500	S&P/TSX Utilities	S&P 500 Utilities	Canada	U.S.	Canada	U.S.	Canada	U.S.	Canada to U.S. / Canadian GDP	U.S. to Canada / U.S. GDP	Canada	U.S.	Exchange Rate (USD / CAD)
1988	11.08	16.61	--	--	4.8	4.1	3.9	4.1	9.83	8.85	16.87	2.23	7.4	5.5	1.23
1989	21.37	31.69	--	--	2.4	3.6	5.1	4.8	9.80	8.49	16.15	2.1	7.1	5.3	1.18
1990	-14.8	-3.11	--	--	0.1	1.9	4.8	5.4	10.76	8.55	16.12	1.96	7.7	5.6	1.17
1991	12.02	30.47	--	--	-2.1	-0.2	5.6	4.2	9.42	7.86	15.55	1.86	9.8	6.8	1.15
1992	-1.43	7.62	--	--	0.9	3.4	1.4	3.0	8.05	7.01	17.28	2.10	10.7	7.5	1.21
1993	32.55	10.08	--	--	2.6	2.9	1.9	3.0	7.22	5.87	20.04	2.51	10.8	6.9	1.29
1994	-0.18	1.32	--	--	4.6	4.1	0.1	2.6	8.42	7.09	22.95	3.00	9.6	6.1	1.37
1995	14.53	37.58	--	--	2.7	2.5	2.2	2.8	8.08	6.57	24.82	3.19	8.6	5.6	1.37
1996	28.35	22.96	--	--	1.7	3.7	1.5	3.0	7.20	6.44	25.94	3.13	8.8	5.4	1.36
1997	14.98	33.36	--	--	4.3	4.5	1.7	2.3	6.11	6.35	26.82	3.51	8.4	4.9	1.38
1998	-1.58	28.58	--	--	4.2	4.4	1.0	1.6	5.30	5.26	28.67	3.94	7.7	4.5	1.48
1999	31.71	21.04	--	--	5.2	4.8	1.8	2.2	5.55	5.65	30.75	3.96	7.0	4.2	1.49
2000	7.41	-9.11	--	--	5.1	4.1	2.7	3.4	5.89	6.03	32.57	3.97	6.1	4.0	1.49
2001	-12.57	-11.89	--	--	1.7	1.1	2.5	2.8	5.47	5.02	30.90	3.82	6.5	4.7	1.55
2002	-12.44	-22.10	--	--	2.8	1.8	2.2	1.6	5.29	4.61	29.26	3.76	7.0	5.8	1.57
2003	26.72	28.68	24.96	26.27	2.0	2.5	2.8	2.3	4.79	4.01	26.34	3.02	6.9	6.0	1.40
2004	14.48	10.88	9.42	24.28	3.2	3.5	1.8	2.7	4.59	4.27	26.36	2.74	6.4	5.5	1.30
2005	24.13	4.91	38.30	16.83	3.1	3.1	2.2	3.4	4.05	4.29	26.01	2.49	6.0	5.1	1.21
2006	17.26	15.79	7.01	21.00	2.7	2.7	2.0	3.2	4.22	4.80	24.23	2.25	5.5	4.6	1.13
2007	9.83	5.49	11.80	19.38	2.1	1.9	2.2	2.8	4.28	4.63	22.64	2.07	5.2	4.6	1.07
2008	-33.00	-37.00	-20.46	-28.98	1.1	-0.3	2.3	3.8	3.58	3.66	22.41	2.10	5.3	5.8	1.07
2009	35.05	26.46	19.00	11.92	-2.8	-3.1	0.3	-0.4	3.29	3.26	17.25	1.93	7.3	9.3	1.14
2010	17.61	15.06	18.42	5.46	3.2	2.4	1.8	1.6	3.20	3.22	17.75	1.85	7.1	9.6	1.03
2011	-8.71	2.10	6.47	19.95	2.6	1.8	2.9	3.2	2.78	2.78	18.72	1.84	6.5	8.9	0.99
2012	7.19	16.00	4.00	0.47	1.8	2.2	1.5	2.1	1.85	1.80	18.59	1.89	6.3	8.1	1.00
25-year Avg.	9.66	11.34	--	--	2.40	2.54	2.33	2.86	5.96	5.45	23.00	2.69	7.4	6.0	1.27
10-year Avg.	11.06	8.84	11.89	11.66	1.90	1.67	1.98	2.47	3.66	3.67	22.03	2.22	6.3	6.8	1.13
5-year Avg.	3.63	4.52	5.49	1.76	1.18	0.60	1.76	2.06	2.94	2.94	18.94	1.92	6.5	8.3	1.05
Correlation	0.73		0.69		0.85		0.77		0.98		0.90		0.23		--
2008-2012															
Correlation	0.95		0.84		0.96		0.92		1.00		0.84		0.96		--
Consensus Forecasts [15]															
2013					2.00	2.00	1.90	2.00	2.20	2.20			7.20	7.70	0.99
2014					2.30	2.80	2.00	2.30	2.70	2.90			7.00	7.20	1.02
2015					2.50	3.10	2.00	2.30	3.60	3.90					

Notes:

- [1] Source: Morningstar and Bloomberg Professional; includes price appreciation and dividend yield
[2] Source: Morningstar and Bloomberg Professional; includes price appreciation and dividend yield
[3] Source: Bloomberg Professional; includes price appreciation and dividend yield, however dividend data for S&P/TSX Utilities not available prior to 2003
[4] Source: Bloomberg Professional; includes price appreciation and dividend yield
[5] Source: Statistics Canada; expenditure-based GDP at market prices, chained 2007 prices, seasonally adjusted
[6] Source: U.S. Bureau of Economic Analysis
[7] Source: Statistics Canada; not seasonally adjusted
[8] Source: U.S. Bureau of Labor Statistics; not seasonally adjusted, U.S. city average, all items
[9] Source: Statistics Canada
[10] Source: Federal Reserve Economic Data
[11] Source: Statistics Canada (exports, merchandise only), U.S. Bureau of Economic Analysis (U.S. GDP), and Federal Reserve Economic Data (currency exchange rate)
[12] Source: U.S. Bureau of Labor Statistics, International Unemployment Rates and Employment Indexes, Seasonally Adjusted
[13] Source: U.S. Bureau of Labor Statistics, International Unemployment Rates and Employment Indexes, Seasonally Adjusted
[14] Source: Federal Reserve Economic Data
[15] Source: Consensus Forecasts, Survey Dates January 14, 2013 (unemployment forecasts) and October 8, 2012 (all other forecasts)

Canadian Utility Proxy Group

Parent Company	S&P Rating	Bloomberg Beta	Operating Company	Authorized ROE	Deemed Equity Ratio
Canadian Utilities	A	0.59	ATCO Electric Distribution	8.75%	39.00%
			ATCO Electric Transmission	8.75%	37.00%
Emera Corp.	BBB+	0.63	Nova Scotia Power Inc.	9.00%	37.50%
Enbridge, Inc.	A-	0.63	Enbridge Gas Distribution, Inc.	8.39%	36.00%
Fortis, Inc.	A-	0.68	Fortis Alberta	8.75%	41.00%
			Fortis BC Power	9.90%	40.00%
			Newfoundland Power	8.80%	44.69%
TransCanada	A-	0.60	TransCanada Pipeline	11.50%	40.00%
Valener, Inc.	A-	0.49	Gaz Metro	8.90%	38.50%
Canadian Proxy Group Avg	A-	0.60		9.19%	39.30%

U.S. Electric Utility Proxy Group

Parent Company	S&P Rating	Bloomberg Beta	Operating Company	Authorized ROE	Deemed Equity Ratio
Consolidated Edison	A-	0.62	ConEdison of New York	10.15%	48.00%
NextEra Energy, Inc.	A-	0.77	Florida Power and Light	10.50%	N/A (1)
Northeast Utilities	A-	0.73	Connecticut Light and Power	9.40%	49.20%
			NSTAR Electric	N/A (1)	N/A (1)
			Public Service of New Hampshire	9.67%	52.40%
			Western Mass. Electric	9.60%	50.70%
Southern Co.	A	0.56	Alabama Power	13.75%	N/A (2)
			Georgia Power	11.15%	N/A (1)
			Gulf Power	10.25%	38.50%
			Mississippi Power	10.63%	N/A (2)
Wisconsin Energy	A-	0.65	Wisconsin Electric	10.40%	52.09%
Xcel Energy Inc.	A-	0.64	NSP - MN	10.37%	52.56%
			NSP - WI	10.40%	52.37%
			Public Service of Colorado	10.00%	56.00%
			Southwestern Public Service	N/A (1)	N/A (1)
U.S. Proxy Group Avg.	A-	0.66		10.48%	50.20%

Notes:

(1) Not specified in most recent rate case, which was resolved through settlement agreement.

(2) Not specified in formula rate plan.

Operating Stats

U.S. Proxy Group Company		Utility	State	S&P Credit Rating	2011 Regulated Electric Revenues (million)	% Industrial Sales	Retail Customers	Notes
Consolidated Edison	ED	Consolidated Edison of New York	NY	A-	8,280	7%	3,329,304	
NextEra Energy	NEE	Florida Power and Light	FL	A-	10,613	2%	4,547,052	
Northeast Utilities	NU	Connecticut Light and Power	CT	A-	2,548	5%	1,212,306	
		NSTAR Electric	MA	A-	2,487	28%	1,163,077	
		Public Service of New Hampshire	NH	A-	1,013	9%	498,216	
		Western Massachusetts Electric	MA	A-	417	10%	206,295	
Southern Co.	SO	Alabama Power	AL	A	5,702	24%	1,434,487	
		Georgia Power	GA	A	8,800	18%	2,360,489	
		Gulf Power	FL	A	1,520	11%	432,403	
		Mississippi Power	MS	A	1,113	25%	186,002	
Wisconsin Energy Corp.	WEC	Wisconsin Electric Power	WI	A-	3,211	24%	1,120,990	
Xcel Energy Inc.	XEL	Northern States Power - Minnesota	MN	A-	3,773	20%	1,399,830	
		Northern States Power - Wisconsin	WI	A-	755	19%	250,133	
		Public Service Company of Colorado	CO	A-	3,114	14%	1,372,919	
		Southwestern Public Service	TX	A-	1,707	25%	376,196	
Canadian Proxy Group		Utility	Province					
Canadian Utilities Ltd.	CU	ATCO Electric Distribution	AB	A	553	36%	213,000	[1]
		ATCO Electric Transmission	AB	A	314	N/A	N/A	[1]
Emera, Inc.	EMA	Nova Scotia Power	NS	BBB+	1,232	22%	490,000	
Enbridge	ENB	Enbridge Gas Distribution	ON	A-	2,574	4%	1,997,481	[2]
Fortis, Inc.	FTS	Fortis Alberta	AB	A-	409	21%	499,000	
		Fortis BC Electric	BC	A-	296	8%	162,000	[3]
		Newfoundland Power	NL	A-	573	0%	243,000	[3]
TransCanada Corp	TRP	TransCanada PipeLine	NEB	A-	5,327	N/A	N/A	[4]
Valener, Inc.	VNR	Gaz Metro	QC	A-	1,501	23%	189,000	
Hydro Quebec		Hydro Quebec Distribution	QC	A+	10,751	31%	4,060,195	[5]
		Hydro Quebec TransEnergie	QC	A+	3,089	N/A	N/A	[5]

Notes

[1] S&P credit rating is for Canadian Utilities.

[2] Regulated revenues are revenues from gas distribution operations.

[3] S&P credit rating is for Fortis Inc.

[3] Regulated revenues are revenues from oil and natural gas pipelines per SNL Financial.

[4] S&P credit rating is the senior unsecured rating for Hydro Québec.

Regulated Generation and Stranded Cost Recovery

U.S. Proxy Group Company		Operating Utility	State	Regulated Generation	# of Customers
Consolidated Edison	ED	Consolidated Edison of New York	NY	Limited	3,329,304
NextEra Energy	NEE	Florida Power and Light	FL	Yes	4,547,052
Northeast Utilities	NU	Connecticut Light and Power	CT	No	1,212,306
		NSTAR Electric	MA	No	1,163,077
		Public Service of New Hampshire	NH	Yes	498,216
		Western Massachusetts Electric	MA	Limited	206,295
Southern Co.	SO	Alabama Power	AL	Yes	1,434,487
		Georgia Power	GA	Yes	2,360,489
		Gulf Power	FL	Yes	432,403
		Mississippi Power	MS	Yes	186,002
Wisconsin Energy Corp.	WEC	Wisconsin Electric Power	WI	Yes	1,120,990
Xcel Energy Inc.	XEL	Northern States Power - Minnesota	MN	Yes	1,399,830
		Northern States Power - Wisconsin	WI	Yes	250,133
		Public Service Company of Colorado	CO	Yes	1,372,919
		Southwestern Public Service	TX	Yes	376,196
Canadian Proxy Group		Utility	Province		
Canadian Utilities Ltd.	CU	ATCO Electric Distribution	AB	No	213,000
		ATCO Electric Transmission	AB	No	N/A
Emera, Inc.	EMA	Nova Scotia Power	NS	Yes	490,000
Enbridge	ENB	Enbridge Gas Distribution	ON	N/A	1,997,481
Fortis, Inc.	FTS	Fortis Alberta	AB	No	499,000
		Fortis BC Electric	BC	Limited	162,000
		Newfoundland Power	NL	Limited	243,000
TransCanada Corp	TRP	TransCanada PipeLine	NEB	N/A	N/A
Valener, Inc.	VNR	Gaz Metro	QC	N/A	189,000
Hydro Quebec		Hydro Quebec Distribution	QC	No	4,060,195
		Hydro Quebec TransEnergie	QC	No	N/A

	U.S.	Canada
Total Number of Customers	19,889,699	3,793,481
Percent that own Regulated Generation	70.28%	12.92%
Percent that own Limited Generation	17.78%	10.68%

Fuel Cost Recovery Risk

U.S. Proxy Group Company		Operating Utility	State	Fuel/PP Costs	PGA	# of Customers
Consolidated Edison	ED	Consolidated Edison of New York	NY	Monthly	N/A	3,329,304
NextEra Energy	NEE	Florida Power and Light	FL	Annually	N/A	4,547,052
Northeast Utilities	NU	Connecticut Light and Power	CT	Bi-Annual	N/A	1,212,306
		NSTAR Electric	MA	Bi-Annual	N/A	1,163,077
		Public Service of New Hampshire	NH	Annually	N/A	498,216
		Western Massachusetts Electric	MA	Bi-Annual	N/A	206,295
Southern Co.	SO	Alabama Power	AL	Periodic	N/A	1,434,487
		Georgia Power	GA	Periodic	N/A	2,360,489
		Gulf Power	FL	Annually	N/A	432,403
		Mississippi Power	MS	Annually	N/A	186,002
Wisconsin Energy Corp.	WEC	Wisconsin Electric Power	WI	Annually	N/A	1,120,990
Xcel Energy Inc.	XEL	Northern States Power - Minnesota	MN	Monthly	N/A	1,399,830
		Northern States Power - Wisconsin	WI	Annually	N/A	250,133
		Public Service Company of Colorado	CO	Quarterly	N/A	1,372,919
		Southwestern Public Service	TX	Periodic	N/A	376,196
Canadian Proxy Group		Utility	Province			
Canadian Utilities Ltd.	CU	ATCO Electric Distribution	AB	N/A	N/A	213,000
		ATCO Electric Transmission	AB	N/A	N/A	N/A
Emera, Inc.	EMA	Nova Scotia Power	NS	Annually	N/A	490,000
Enbridge	ENB	Enbridge Gas Distribution	ON	N/A	Quarterly	1,997,481
Fortis, Inc.	FTS	Fortis Alberta	AB	N/A	N/A	499,000
		Fortis BC Electric	BC	N/A	N/A	162,000
		Newfoundland Power	NL	N/A	N/A	243,000
TransCanada Corp	TRP	TransCanada PipeLine	NEB	N/A	N/A	N/A
Valener, Inc.	VNR	Gaz Metro	QC	N/A	Monthly	189,000
Hydro Quebec		Hydro Quebec Distribution	QC	Annually	N/A	4,060,195
		Hydro Quebec TransEnergie	QC	N/A	N/A	N/A

	U.S.	Canada
Total Number of Customers	19,889,699	3,793,481
Percent with Monthly Fuel Cost Recovery	23.78%	0.00%
Percent with Quarterly Cost Recovery	6.90%	0.00%
Percent with Bi-Annual Fuel Cost Recovery	12.98%	0.00%
Percent with Annual Fuel Cost Recovery	35.37%	12.92%
Percent with Periodic Fuel Cost Recovery	20.97%	0.00%
Percent with Monthly PGA	0.00%	4.98%
Percent with Quarterly PGA	0.00%	52.66%

Volume/Demand Risk

U.S. Proxy Group Company		Operating Utility	State	Decoupling	LRAM	Weather Norm	# of Customers
Consolidated Edison	ED	Consolidated Edison of New York	NY	Yes	N/A	Yes	3,329,304
NextEra Energy	NEE	Florida Power and Light	FL	No	N/A	No	4,547,052
Northeast Utilities	NU	Connecticut Light and Power	CT	No	N/A	No	1,212,306
		NSTAR Electric	MA	No	N/A	No	1,163,077
		Public Service of New Hampshire	NH	No	N/A	No	498,216
		Western Massachusetts Electric	MA	Yes	N/A	Yes	206,295
Southern Co.	SO	Alabama Power [1]	AL	Yes	N/A	No	1,434,487
		Georgia Power	GA	No	N/A	No	2,360,489
		Gulf Power	FL	No	N/A	No	432,403
		Mississippi Power [1]	MS	Yes	N/A	No	186,002
Wisconsin Energy Corp.	WEC	Wisconsin Electric Power	WI	No	N/A	No	1,120,990
Xcel Energy Inc.	XEL	Northern States Power - Minnesota	MN	No	N/A	No	1,399,830
		Northern States Power - Wisconsin	WI	No	N/A	No	250,133
		Public Service Company of Colorado	CO	No	N/A	No	1,372,919
		Southwestern Public Service	TX	No	N/A	No	376,196
Canadian Proxy Group		Utility	Province				
Canadian Utilities Ltd.	CU	ATCO Electric Distribution	AB	No	N/A	No	213,000
		ATCO Electric Transmission	AB	Yes	N/A	No	N/A
Emera, Inc.	EMA	Nova Scotia Power	NS	No	N/A	No	490,000
Enbridge	ENB	Enbridge Gas Distribution	ON	No	Yes	No	1,997,481
Fortis, Inc.	FTS	Fortis Alberta	AB	No	N/A	No	499,000
		Fortis BC Electric	BC	Yes	N/A	No	162,000
		Newfoundland Power	NL	No	N/A	Yes	243,000
TransCanada Corp	TRP	TransCanada PipeLine	NEB	No	N/A	No	N/A
Valener, Inc.	VNR	Gaz Metro	QC	Yes	N/A	Yes	189,000
Hydro Quebec		Hydro Quebec Distribution	QC	No	N/A	Yes	4,060,195
		Hydro Quebec TransEnergie	QC	No	N/A	No	N/A

	U.S.	Canada
Total Number of Customers	19,889,699	3,793,481
Percent with Decoupling	25.92%	9.25%
Percent with LRAM	0.00%	52.66%
Percent with Weather Normalization	17.78%	11.39%

[1] The company has a formula rate plan or revenue stabilization plan that includes protection against volumetric risk.

Capital Cost Recovery Risk

U.S. Proxy Group Company		Operating Utility	State	Pre-Approval	CWIP	AFUDC	Cost Tracking Mechanism	# of Customers
Consolidated Edison	ED	Consolidated Edison of New York	NY	Yes	No	Yes	No	3,329,304
NextEra Energy	NEE	Florida Power and Light	FL	Yes	Yes	Yes	Yes	4,547,052
Northeast Utilities	NU	Connecticut Light and Power	CT	Yes	No	Yes	Yes	1,212,306
		NSTAR Electric	MA	No	No	Yes	Yes	1,163,077
		Public Service of New Hampshire	NH	No	No	Yes	Yes	498,216
		Western Massachusetts Electric	MA	No	No	Yes	Yes	206,295
Southern Co.	SO	Alabama Power	AL	No	No	Yes	Yes	1,434,487
		Georgia Power	GA	Yes	Yes	Yes	No	2,360,489
		Gulf Power	FL	Yes	Yes	Yes	Yes	432,403
		Mississippi Power	MS	Yes	Yes	Yes	No	186,002
Wisconsin Energy Corp.	WEC	Wisconsin Electric Power	WI	Yes	Yes [1]	Yes	No	1,120,990
Xcel Energy Inc.	XEL	Northern States Power - Minnesota	MN	No	Limited	Yes	Yes	1,399,830
		Northern States Power - Wisconsin	WI	Yes	Yes [1]	Yes	No	250,133
		Public Service Company of Colorado	CO	No	Yes	Yes	Yes	1,372,919
		Southwestern Public Service	TX	No	No	Yes	Yes	376,196
Canadian Proxy Group		Utility	Province					
Canadian Utilities Ltd.	CU	ATCO Electric Distribution	AB	No	No	Yes	Yes	213,000
		ATCO Electric Transmission	AB	No	Yes	Yes	Yes	N/A
Emera, Inc.	EMA	Nova Scotia Power	NS	Yes	No	Yes	No	490,000
Enbridge	ENB	Enbridge Gas Distribution	ON	No	No	Yes	Yes	1,997,481
Fortis, Inc.	FTS	Fortis Alberta	AB	No	No	Yes	Yes	499,000
		Fortis BC Electric	BC	Yes	No	Yes	Yes	162,000
		Newfoundland Power	NL	No	No	Yes	No	243,000
TransCanada Corp	TRP	TransCanada PipeLine	NEB	No	No	Yes	No	N/A
Valener, Inc.	VNR	Gaz Metro	QC	Yes	No	Yes	No	189,000
Hydro Quebec		Hydro Quebec Distribution	QC	Yes	No	Yes	No	4,060,195
		Hydro Quebec TransEnergie	QC	Yes	No	Yes	No	N/A

	U.S.	Canada
Total Number of Customers	19,889,699	3,793,481
Percent with Pre-Approval of Capital Projects	67.57%	22.17%
Percent with CWIP in Rate Base	44.74%	0.00%
Percent with AFUDC	100.00%	100.00%
Percent with Cost Tracking Mechanism	63.56%	75.70%

Notes:

[1] CWIP is not included in rate base, but Wisconsin PSC allows recovery of 50% of CWIP through adder to return on rate base.

Rate Regulation and Earnings Sharing

U.S. Proxy Group Company		Operating Utility	State	Cost of Svc	Incentive Reg	Multi-Year Rate	Formula Rate	ESM	# of Customers
Consolidated Edison	ED	Consolidated Edison of New York	NY	No	Yes	Yes	No	Yes	3,329,304
NextEra Energy	NEE	Florida Power and Light	FL	Yes	No	No	No	No	4,547,052
Northeast Utilities	NU	Connecticut Light and Power	CT	No	Yes	Yes	No	Yes	1,212,306
		NSTAR Electric	MA	No	Yes	Yes	No	Yes	1,163,077
		Public Service of New Hampshire	NH	No	Yes	Yes	No	Yes	498,216
		Western Massachusetts Electric	MA	Yes	No	No	No	No	206,295
Southern Co.	SO	Alabama Power	AL	No	Yes	No	Yes	Yes	1,434,487
		Georgia Power	GA	No	Yes	Yes	No	Yes	2,360,489
		Gulf Power	FL	Yes	No	No	No	No	432,403
		Mississippi Power	MS	No	Yes	No	Yes	Yes	186,002
Wisconsin Energy Corp.	WEC	Wisconsin Electric Power	WI	Yes	No	No	No	No	1,120,990
Xcel Energy Inc.	XEL	Northern States Power - Minnesota	MN	Yes	No	No	No	No	1,399,830
		Northern States Power - Wisconsin	WI	Yes	No	No	No	No	250,133
		Public Service Company of Colorado	CO	No	Yes	Yes	No	Yes	1,372,919
		Southwestern Public Service	TX	Yes	No	No	No	No	376,196
Canadian Proxy Group		Utility	Province						
Canadian Utilities Ltd.	CU	ATCO Electric Distribution	AB	No	Yes	Yes	No	No	213,000
		ATCO Electric Transmission	AB	Yes	No	No	No	No	N/A
Emera, Inc.	EMA	Nova Scotia Power	NS	Yes	No	No	No	No	490,000
Enbridge	ENB	Enbridge Gas Distribution	ON	No	Yes	Yes	No	Yes	1,997,481
Fortis, Inc.	FTS	Fortis Alberta	AB	No	Yes	Yes	No	No	499,000
		Fortis BC Electric	BC	Yes	No	No	No	No	162,000
		Newfoundland Power	NL	Yes	No	No	No	Yes	243,000
TransCanada Corp	TRP	TransCanada PipeLine	NEB	No	Yes	No	No	No	N/A
Valener, Inc.	VNR	Gaz Metro	QC	No	Yes	Yes	No	Yes	189,000
Hydro Quebec		Hydro Quebec Distribution	QC	Yes	No	No	No	No	4,060,195
		Hydro Quebec TransEnergie	QC	Yes	No	No	No	No	N/A

	U.S.	Canada
Total Number of Customers	19,889,699	3,793,481
Percent with Cost of Service Regulation	41.90%	23.59%
Percent with Incentive Regulation Plan	58.10%	76.41%
Percent with Multi-year Rate Plan	49.96%	76.41%
Percent with Formula Rates	8.15%	0.00%
Percent with Earnings Sharing	58.10%	64.04%

Notes:

[1] Company is under cost of service regulation for 2013 rate year, but has filed incentive regulation plan that will take effect in 2014 rate year, if approved. Company previously operated under incentive regulation plan that expired in 2012.

Regulatory Lag

U.S. Proxy Group Company		Operating Utility	State	Test Year	Interim Rates	Rate Case Lag	# of Customers
Consolidated Edison	ED	Consolidated Edison of New York	NY	Forecast	Emergency	10.5	3,329,304
NextEra Energy	NEE	Florida Power and Light	FL	Forecast	Y	9	4,547,052
Northeast Utilities	NU	Connecticut Light and Power	CT	HKM	Emergency	6	1,212,306
		NSTAR Electric	MA	HKM	Emergency	N/A	1,163,077
		Public Service of New Hampshire	NH	HKM	Y	12	498,216
		Western Massachusetts Electric	MA	HKM	Emergency	6.5	206,295
Southern Co.	SO	Alabama Power	AL	Forecast	N/A	N/A	1,434,487
		Georgia Power	GA	Forecast	Y	6	2,360,489
		Gulf Power	FL	Forecast	Y	8	432,403
		Mississippi Power	MS	Forecast	N/A	N/A	186,002
Wisconsin Energy Corp.	WEC	Wisconsin Electric Power	WI	Forecast	Y	8	1,120,990
Xcel Energy Inc.	XEL	Northern States Power - Minnesota	MN	Partial	Y	17	1,399,830
		Northern States Power - Wisconsin	WI	Forecast	Y	6.5	250,133
		Public Service Company of Colorado	CO	Forecast	Emergency	5	1,372,919
		Southwestern Public Service	TX	HKM	Y	10	376,196
Canadian Proxy Group		Utility	Province				
Canadian Utilities Ltd.	CU	ATCO Electric Distribution	AB	Forecast	Y	11	213,000
		ATCO Electric Transmission	AB	Forecast	Y	11	N/A
Emera, Inc.	EMA	Nova Scotia Power	NS	Forecast	N	6.5	490,000
Enbridge	ENB	Enbridge Gas Distribution	ON	Forecast	N/A	N/A	1,997,481
Fortis, Inc.	FTS	Fortis Alberta	AB	Forecast	Y	11	499,000
		Fortis BC Electric	BC	Forecast	Y	12	162,000
		Newfoundland Power	NL	Forecast	Y	6	243,000
TransCanada Corp	TRP	TransCanada PipeLine	NEB	Forecast	Y	12	N/A
Valener, Inc.	VNR	Gaz Metro	QC	Forecast	N	N/A	189,000
Hydro Quebec		Hydro Quebec Distribution	QC	Forecast	N	8	4,060,195
		Hydro Quebec TransEnergie	QC	Forecast	Y	10	N/A

	U.S.	Canada
Total Number of Customers	19,889,699	3,793,481
Percent with Forecasted Test Year	75.59%	100.00%
Percent with Partially Forecasted Test Year	7.04%	0.00%
Percent with Historical Adjusted Test Year	17.38%	0.00%
Percent with Interim Rates	55.23%	29.45%
Percent with Interim Rates in Financial Emergency	36.62%	0.00%
Rate Case Lag in Months	8.71	9.93

Other Cost Recovery

				Pension	Bad Debt	Storm Cost	Interest Rate	Energy	
U.S. Proxy Group Company		Operating Utility	State	Expense	Expense	Recovery	Tracker	Efficiency	# of
								Cost	Customers
Consolidated Edison	ED	Consolidated Edison of New York	NY	Yes	No	Yes	Yes	Yes	3,329,304
NextEra Energy	NEE	Florida Power and Light	FL	No	No	Yes	No	Yes	4,547,052
Northeast Utilities	NU	Connecticut Light and Power	CT	No	No	Yes	No	No	1,212,306
		NSTAR Electric	MA	Yes	Yes	Yes	No	Yes	1,163,077
		Public Service of New Hampshire	NH	No	No	Yes	No	No	498,216
		Western Massachusetts Electric	MA	Yes	Yes	Yes	No	Yes	206,295
Southern Co.	SO	Alabama Power	AL	No	No	Yes	No	No	1,434,487
		Georgia Power	GA	No	No	Yes	No	Yes	2,360,489
		Gulf Power	FL	No	No	Yes	No	Yes	432,403
		Mississippi Power	MS	No	No	Yes	No	No	186,002
Wisconsin Energy Corp.	WEC	Wisconsin Electric Power	WI	Yes	Yes	No	No	No	1,120,990
Xcel Energy Inc.	XEL	Northern States Power - Minnesota	MN	Yes	No	No	No	Yes	1,399,830
		Northern States Power - Wisconsin	WI	No	No	No	No	No	250,133
		Public Service Company of Colorado	CO	No	No	No	No	Yes	1,372,919
		Southwestern Public Service	TX	No	No	Yes	No	Yes	376,196
Canadian Proxy Group		Utility	Province						
Canadian Utilities Ltd.	CU	ATCO Electric Distribution	AB	Yes	No	No	No	No	213,000
		ATCO Electric Transmission	AB	Yes	No	No	No	No	N/A
Emera, Inc.	EMA	Nova Scotia Power	NS	No	No	No	No	Yes	490,000
Enbridge	ENB	Enbridge Gas Distribution	ON	Yes	No	No	No	Yes	1,997,481
Fortis, Inc.	FTS	Fortis Alberta	AB	No	No	No	No	No	499,000
		Fortis BC Electric	BC	Yes	No	No	Yes	Yes	162,000
		Newfoundland Power	NL	Yes	No	No	No	Yes	243,000
TransCanada Corp	TRP	TransCanada PipeLine	NEB	No	No	No	Yes	No	N/A
Valener, Inc.	VNR	Gaz Metro	QC	No	Yes	No	Yes	Yes	189,000
Hydro Quebec		Hydro Quebec Distribution	QC	Yes	No	Limited	No	No	4,060,195
		Hydro Quebec TransEnergie	QC	Yes	No	No	No	No	N/A

	U.S.	Canada
Total Number of Customers	19,889,699	3,793,481
Percent with Pension Expense Cost Recovery	36.30%	68.95%
Percent with Bad Debt Expense Cost Recovery	12.52%	4.98%
Percent with Storm Cost Recovery	79.17%	0.00%
Percent with Interest Rate Tracker for Change in Interest Rates	16.74%	9.25%
Percent with Energy Efficiency and DSM Cost Recovery	76.36%	81.23%

Company Name	Ticker	Debt to Capital Ratio	EBIT to Interest Coverage	FFO to Interest Coverage	FFO / Debt Ratio	Debt to EBITDA
Hydro Quebec Distribution		65%	1.88	3.46	0.24	3.98
Hydro Quebec TransEnergie		70%	1.62	2.66	0.19	5.20
U.S. Proxy Group						
Consolidated Edison	ED	48%	3.80	5.10	0.28	3.40
NextEra Energy	NEE	61%	3.37	5.17	0.24	4.11
Northeast Utilities	NU	57%	3.28	4.58	0.22	4.69
Southern Co.	SO	53%	5.07	7.38	0.30	3.28
Wisconsin Energy Corp	WEC	57%	4.29	6.43	0.29	3.85
Xcel Energy Inc.	XEL	54%	3.33	5.11	0.29	3.45
U.S. Proxy Group		55%	3.86	5.63	0.27	3.80
Canadian Proxy Group						
Canadian Utilities Limited	CU	53%	4.07	5.23	0.29	3.14
Emera Incorporated	EMA	66%	2.23	4.03	0.22	5.04
Enbridge Inc.	ENB	64%	3.19	4.22	0.20	4.80
Fortis Inc.	FTS	56%	2.24	3.34	0.19	5.22
TransCanada Corporation	TRP	54%	3.30	4.63	0.21	4.59
Valener, Inc.	VNR [1]	63%	2.67	3.83	0.22	4.42
Canadian Proxy Group		60%	2.95	4.21	0.22	4.54

Notes & Sources:

Unless otherwise noted, all values are based on holding-company financial data downloaded from SNL Financial.

[1] Credit metrics shown are those for Gaz Métro Limited Partnership.

Capital Asset Pricing Model
Reconciled Approach

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
					Industry- Adjusted Beta	Industry Index Beta	Mean Market- Adjusted Beta	Average Beta	Risk Free Rate	Average Market Risk Premium	Straight CAPM Calculation	Flotation Cost	"Simple" CAPM	Adjustment for Other Models	Total CAPM
US Proxy Group	Ticker	Raw Beta	Bloomberg	Value Line											
Consolidated Edison	ED	0.44	0.62	0.60	0.50	0.63	0.61	0.56	4.23%	6.67%	7.94%	0.30%	8.24%	0.75%	8.99%
NextEra Energy, Inc.	NEE	0.65	0.77	0.70	0.65	0.63	0.73	0.69	4.23%	6.67%	8.83%	0.30%	9.13%	0.75%	9.88%
Northeast Utilities	NU	0.59	0.73	0.70	0.61	0.63	0.71	0.66	4.23%	6.67%	8.62%	0.30%	8.92%	0.75%	9.67%
Southern Co.	SO	0.34	0.56	0.55	0.44	0.63	0.56	0.50	4.23%	6.67%	7.55%	0.30%	7.85%	0.75%	8.60%
Wisconsin Energy	WEC	0.47	0.65	0.60	0.52	0.63	0.62	0.57	4.23%	6.67%	8.05%	0.30%	8.35%	0.75%	9.10%
Xcel Energy, Inc.	XEL	0.47	0.64	0.60	0.52	0.63	0.62	0.57	4.23%	6.67%	8.05%	0.30%	8.35%	0.75%	9.10%
MEAN		0.49	0.66	0.63	0.54	0.63	0.64	0.59			8.17%		8.47%		9.22%

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
					Industry- Adjusted Beta	Industry Index Beta	Mean Market- Adjusted Beta	Average Beta	Risk Free Rate	Average Market Risk Premium	Straight CAPM Calculation	Flotation Cost	"Simple" CAPM	Adjustment for Other Models	Total CAPM
Canada Proxy Group	Ticker	Raw Beta	Bloomberg	Value Line											
Canadian Utilities Limited	CU	0.38	0.59		0.44	0.56	0.59	0.52	4.23%	6.67%	7.67%	0.30%	7.97%	0.75%	8.72%
Emera Inc.	EMA	0.44	0.63		0.48	0.56	0.63	0.56	4.23%	6.67%	7.93%	0.30%	8.23%	0.75%	8.98%
Enbridge Inc.	ENB	0.45	0.63	0.60	0.49	0.56	0.62	0.55	4.23%	6.67%	7.91%	0.30%	8.21%	0.75%	8.96%
Fortis Inc.	FTS	0.52	0.68	0.60	0.53	0.56	0.64	0.59	4.23%	6.67%	8.14%	0.30%	8.44%	0.75%	9.19%
TransCanada Corporation	TRP	0.41	0.60	0.85	0.46	0.56	0.73	0.59	4.23%	6.67%	8.18%	0.30%	8.48%	0.75%	9.23%
Valener Inc.	VNR	0.24	0.49		0.35	0.56	0.49	0.42	4.23%	6.67%	7.04%	0.30%	7.34%	0.75%	8.09%
MEAN		0.41	0.60	0.68	0.46	0.56	0.62	0.54			7.81%		8.11%		8.86%

Notes:

- [1] Source: Bloomberg Professional; average of five years of weekly raw betas as of February 28, 2013
[2] Source: Bloomberg Professional; average of five years of weekly market-adjusted betas
[3] Source: Value Line as of February 28, 2013
[4] Equals $(2/3) \times [1] + (1/3) \times [5]$
[5] Source: Bloomberg Professional; average of five years of weekly betas for S&P utilities index
[6] Equals mean of [2] and [3]
[7] Equals Average of [4],[6]
[8] Source: Equals average long-term Consensus Forecast of 10-year Canadian government bond yield for the period 2013-2022 plus the 30-day average spread between 10- and 30-year bond ending February 28, 2013.
[9] Source: Average of the Ibbotson Canada historcal risk premium (1936-2012), Ibbotson US historcal risk premium (1926-2012), Bloomberg; TSX total return less [8] as of March 1, 2013, Bloomberg; S&P 500 total return less [8] as of March 1, 2013
[10] Equals $[8] + [7] \times [9]$
[11] Flotation Costs Allowed by the Regie in Past Rate Cases
[12] Equals $[10] + [11]$
[13] Adjustment for Results of Other Models as Noted by Regie in 2012 Rate Case
[14] Equals $[12] + [13]$

Foward-Looking Market Risk Premium -- U.S.

[1] Estimated Weighted Average Dividend Yield	2.28%
[2] Estimated Weighted Average Long-Term Growth Rate	10.39%
[3] S&P 500 Estimated Required Market Return	12.78%
[4] 10-Year Government Bond Yield Forecast (2013-2022)	3.62%
[5] Credit Spread between 10- and 30-Year Bond Yield	0.61%
[6] Risk-Free Rate	4.23%
[7] Implied Market Risk Premium	8.55%

Company Name	Ticker	[8] Shares Outstanding	[9] Price	[10] Market Cap.	[11] Weight	[12] Div. Yld.	[13] Earnings Growth	[14] Div. Yld. x Weight	[15] Earn. Gr. x Weight
3M Co	MMM	690.0	103.68	71,538.2	0.51%	2.44%	9.67%	0.01%	0.05%
Abbott Laboratories	ABT	1,570.7	33.60	52,774.7	0.38%	1.68%	10.61%	0.01%	0.04%
AbbVie Inc	ABBV	1,570.7	37.96	59,622.9	0.43%	4.21%	5.77%	0.02%	0.02%
Abercrombie & Fitch Co	ANF	79.6	46.22	3,677.4	0.03%	1.64%	16.14%	0.00%	0.00%
Accenture PLC	ACN	644.3	74.77	48,176.9	0.35%	2.18%	12.32%	0.01%	0.04%
ACE Ltd	ACE	340.3	85.54	29,111.1	0.21%	2.24%	8.33%	0.00%	0.02%
Actavis Inc	ACT	127.8	85.50	10,929.7	0.08%	0.00%	12.04%	0.00%	0.01%
Adobe Systems Inc	ADBE	498.8	39.84	19,871.8	0.14%	0.00%	10.20%	0.00%	0.01%
ADT Corp/The	ADT	232.2	48.00	11,146.9	0.08%	1.00%	10.50%	0.00%	0.01%
Advanced Micro Devices Inc	AMD	714.1	2.43	1,735.2	0.01%	0.00%	12.50%	0.00%	0.00%
AES Corp/VA	AES	745.8	11.88	8,859.7	0.06%	1.01%	8.00%	0.00%	0.01%
Aetna Inc	AET	328.0	47.41	15,550.5	0.11%	1.53%	10.40%	0.00%	0.01%
Aflac Inc	AFL	467.7	50.19	23,475.9	0.17%	2.86%	10.67%	0.00%	0.02%
Agilent Technologies Inc	A	347.9	41.89	14,575.0	0.10%	1.05%	8.71%	0.00%	0.01%
AGL Resources Inc	GAS	117.9	40.05	4,721.0	0.03%	4.66%	5.50%	0.00%	0.00%
Air Products & Chemicals Inc	APD	212.9	86.20	18,347.7	0.13%	3.10%	9.40%	0.00%	0.01%
Airgas Inc	ARG	75.9	100.84	7,655.5	0.05%	1.43%	12.87%	0.00%	0.01%
Akamai Technologies Inc	AKAM	177.5	36.59	6,493.5	0.05%	0.00%	15.40%	0.00%	0.01%
Alcoa Inc	AA	1,069.3	8.42	9,003.7	0.06%	1.43%	6.50%	0.00%	0.00%
Alexion Pharmaceuticals Inc	ALXN	195.2	86.69	16,922.7	0.12%	0.00%	40.57%	0.00%	0.05%
Allegheny Technologies Inc	ATI	107.5	30.25	3,251.1	0.02%	2.38%	15.00%	0.00%	0.00%
Allergan Inc/United States	AGN	307.5	108.75	33,446.0	0.24%	0.19%	13.58%	0.00%	0.03%
Allstate Corp/The	ALL	477.4	46.26	22,086.7	0.16%	2.12%	8.33%	0.00%	0.01%
Altera Corp	ALTR	319.8	35.41	11,322.4	0.08%	1.16%	13.50%	0.00%	0.01%
Altria Group Inc	MO	2,009.9	33.49	67,310.0	0.48%	5.51%	7.52%	0.03%	0.04%
Amazon.com Inc	AMZN	454.6	266.18	120,992.4	0.87%	0.00%	34.70%	0.00%	0.30%
Ameren Corp	AEE	242.6	33.84	8,210.8	0.06%	4.78%	-4.00%	0.00%	0.00%
American Electric Power Co Inc	AEP	485.7	46.66	22,661.3	0.16%	4.15%	4.40%	0.01%	0.01%
American Express Co	AXP	1,104.7	62.40	68,930.2	0.49%	1.37%	10.07%	0.01%	0.05%
American International Group Inc	AIG	1,476.3	37.79	55,790.2	0.40%	0.22%	10.75%	0.00%	0.04%
American Tower Corp	AMT	395.1	78.00	30,818.0	0.22%	1.40%	24.63%	0.00%	0.05%
Ameriprise Financial Inc	AMP	203.5	67.98	13,832.0	0.10%	2.54%	12.00%	0.00%	0.01%
AmerisourceBergen Corp	ABC	230.2	48.01	11,050.6	0.08%	1.61%	11.50%	0.00%	0.01%
Amgen Inc	AMGN	748.4	92.56	69,274.7	0.50%	2.01%	8.69%	0.01%	0.04%
Amphenol Corp	APH	159.7	71.68	11,447.2	0.08%	0.62%	18.50%	0.00%	0.02%
Anadarko Petroleum Corp	APC	500.6	79.72	39,905.1	0.29%	0.46%	14.09%	0.00%	0.04%
Analog Devices Inc	ADI	306.0	45.16	13,818.3	0.10%	2.92%	12.50%	0.00%	0.01%
Aon PLC	AON	311.6	60.91	18,977.9	0.14%	1.04%	10.00%	0.00%	0.01%
Apache Corp	APA	392.0	73.69	28,886.5	0.21%	1.03%	6.34%	0.00%	0.01%
Apartment Investment & Management Co	AIV	145.8	29.71	4,332.3	0.03%	3.10%	9.54%	0.00%	0.00%
Apollo Group Inc	APOL	112.1	16.60	1,860.3	0.01%	0.00%	9.26%	0.00%	0.00%
Apple Inc	AAPL	939.1	431.23	404,950.0	2.90%	2.51%	17.63%	0.07%	0.51%
Applied Materials Inc	AMAT	1,200.0	13.61	16,332.6	0.12%	2.56%	9.67%	0.00%	0.01%
Archer-Daniels-Midland Co	ADM	658.6	31.89	21,002.5	0.15%	2.10%	n/a	0.00%	n/a
Assurant Inc	AIZ	78.8	41.68	3,284.8	0.02%	2.21%	9.67%	0.00%	0.00%
AT&T Inc	T	5,491.6	35.99	197,643.0	1.42%	5.03%	5.75%	0.07%	0.08%
Autodesk Inc	ADSK	224.7	37.50	8,426.3	0.06%	0.00%	15.33%	0.00%	0.01%
Automatic Data Processing Inc	ADP	485.0	61.60	29,877.1	0.21%	2.71%	9.57%	0.01%	0.02%

Foward-Looking Market Risk Premium -- U.S.

AutoNation Inc	AN	121.0	43.32	5,241.2	0.04%	n/a	20.48%	n/a	0.01%
AutoZone Inc	AZO	36.1	376.95	13,600.0	0.10%	0.00%	16.47%	0.00%	0.02%
AvalonBay Communities Inc	AVB	114.4	125.84	14,396.8	0.10%	3.36%	8.57%	0.00%	0.01%
Avery Dennison Corp	AVY	100.1	40.84	4,088.3	0.03%	2.67%	7.00%	0.00%	0.00%
Avon Products Inc	AVP	432.2	19.68	8,505.0	0.06%	1.21%	15.29%	0.00%	0.01%
Baker Hughes Inc	BHI	441.8	44.30	19,572.1	0.14%	1.36%	13.00%	0.00%	0.02%
Ball Corp	BLL	149.4	44.16	6,599.2	0.05%	1.13%	10.00%	0.00%	0.00%
Bank of America Corp	BAC	10,778.3	11.36	122,441.0	0.88%	0.93%	8.67%	0.01%	0.08%
Bank of New York Mellon Corp/The	BK	1,162.0	27.15	31,547.0	0.23%	2.19%	12.67%	0.00%	0.03%
Baxter International Inc	BAX	545.9	68.84	37,581.7	0.27%	2.46%	8.68%	0.01%	0.02%
BB&T Corp	BBT	699.8	30.62	21,428.7	0.15%	2.97%	6.50%	0.00%	0.01%
Beam Inc	BEAM	160.3	60.92	9,767.1	0.07%	1.49%	11.92%	0.00%	0.01%
Becton Dickinson and Co	BDX	194.0	88.62	17,188.8	0.12%	2.20%	7.85%	0.00%	0.01%
Bed Bath & Beyond Inc	BBBY	226.1	56.83	12,851.3	0.09%	0.00%	13.78%	0.00%	0.01%
Bemis Co Inc	BMS	103.0	37.42	3,854.2	0.03%	2.74%	7.00%	0.00%	0.00%
Berkshire Hathaway Inc	BRK/B	1,099.8	102.08	112,266.9	0.80%	n/a	n/a	n/a	n/a
Best Buy Co Inc	BBY	338.1	16.84	5,693.4	0.04%	3.86%	1.50%	0.00%	0.00%
Biogen Idec Inc	BIIB	236.3	168.24	39,757.2	0.28%	0.00%	18.38%	0.00%	0.05%
BlackRock Inc	BLK	170.0	236.70	40,229.8	0.29%	2.86%	11.94%	0.01%	0.03%
BMC Software Inc	BMC	142.9	40.49	5,785.6	0.04%	0.00%	15.00%	0.00%	0.01%
Boeing Co/The	BA	756.2	77.19	58,368.4	0.42%	2.43%	11.48%	0.01%	0.05%
BorgWarner Inc	BWA	115.6	74.92	8,663.7	0.06%	0.10%	15.00%	0.00%	0.01%
Boston Properties Inc	BXP	151.6	103.21	15,650.7	0.11%	2.53%	4.84%	0.00%	0.01%
Boston Scientific Corp	BSX	1,357.4	7.37	10,004.2	0.07%	0.00%	7.78%	0.00%	0.01%
Bristol-Myers Squibb Co	BMJ	1,637.4	37.17	60,860.5	0.44%	3.75%	7.19%	0.02%	0.03%
Broadcom Corp	BRCM	518.0	33.85	17,531.7	0.13%	1.30%	14.43%	0.00%	0.02%
Brown-Forman Corp	BF/B	129.0	65.55	8,457.5	0.06%	1.50%	12.50%	0.00%	0.01%
CA Inc	CA	455.9	24.44	11,140.5	0.08%	4.11%	10.00%	0.00%	0.01%
Cablevision Systems Corp	CVC	209.0	13.78	2,880.3	0.02%	4.43%	2.00%	0.00%	0.00%
Cabot Oil & Gas Corp	COG	210.2	63.19	13,285.2	0.10%	0.14%	n/a	0.00%	n/a
Cameron International Corp	CAM	247.9	62.85	15,577.6	0.11%	0.00%	17.00%	0.00%	0.02%
Campbell Soup Co	CPB	314.4	42.09	13,233.8	0.09%	2.89%	6.00%	0.00%	0.01%
Capital One Financial Corp	COF	582.2	51.75	30,131.4	0.22%	1.53%	8.00%	0.00%	0.02%
Cardinal Health Inc	CAH	340.9	46.45	15,832.9	0.11%	2.17%	11.40%	0.00%	0.01%
CareFusion Corp	CFN	222.6	32.90	7,323.2	0.05%	0.00%	10.58%	0.00%	0.01%
CarMax Inc	KMX	228.2	38.33	8,747.5	0.06%	n/a	12.78%	n/a	0.01%
Carnival Corp	CCL	594.5	35.81	21,288.5	0.15%	3.37%	15.85%	0.01%	0.02%
Caterpillar Inc	CAT	655.0	91.27	59,786.3	0.43%	2.23%	9.75%	0.01%	0.04%
CBRE Group Inc	CBG	329.2	24.39	8,030.0	0.06%	n/a	11.67%	n/a	0.01%
CBS Corp	CBS	586.4	43.50	25,510.5	0.18%	1.14%	9.69%	0.00%	0.02%
Celgene Corp	CELG	418.7	105.71	44,265.5	0.32%	0.00%	22.42%	0.00%	0.07%
CenterPoint Energy Inc	CNP	427.7	21.48	9,186.4	0.07%	3.86%	5.67%	0.00%	0.00%
CenturyLink Inc	CTL	624.3	34.84	21,749.4	0.16%	6.20%	3.30%	0.01%	0.01%
Cerner Corp	CERN	172.2	89.15	15,352.3	0.11%	0.00%	18.00%	0.00%	0.02%
CF Industries Holdings Inc	CF	63.0	200.97	12,662.0	0.09%	0.80%	10.00%	0.00%	0.01%
CH Robinson Worldwide Inc	CHRW	161.2	57.05	9,196.0	0.07%	2.50%	14.80%	0.00%	0.01%
Charles Schwab Corp/The	SCHW	1,278.0	16.41	20,971.8	0.15%	1.51%	18.39%	0.00%	0.03%
Chesapeake Energy Corp	CHK	664.7	19.64	13,053.8	0.09%	1.73%	22.42%	0.00%	0.02%
Chevron Corp	CVX	1,942.7	116.88	227,062.5	1.63%	3.19%	4.76%	0.05%	0.08%
Chipotle Mexican Grill Inc	CMG	31.0	318.48	9,883.1	0.07%	0.00%	19.34%	0.00%	0.01%
Chubb Corp/The	CB	261.8	84.54	22,132.6	0.16%	2.00%	9.00%	0.00%	0.01%
Cigna Corp	CI	286.0	58.26	16,659.7	0.12%	0.07%	9.87%	0.00%	0.01%
Cincinnati Financial Corp	CINF	163.2	45.08	7,358.3	0.05%	3.62%	5.00%	0.00%	0.00%
Cintas Corp	CTAS	123.3	43.67	5,383.9	0.04%	1.44%	11.17%	0.00%	0.00%
Cisco Systems Inc	CSCO	5,332.0	20.81	110,958.4	0.79%	2.71%	9.88%	0.02%	0.08%
Citigroup Inc	C	3,038.8	42.04	127,749.4	0.91%	0.83%	9.80%	0.01%	0.09%
Citrix Systems Inc	CTXS	186.4	71.41	13,311.1	0.10%	0.00%	15.44%	0.00%	0.01%
Cliffs Natural Resources Inc	CLF	158.2	25.19	3,984.9	0.03%	2.38%	7.50%	0.00%	0.00%
Clorox Co/The	CLX	131.0	83.99	10,999.5	0.08%	3.07%	8.68%	0.00%	0.01%
CME Group Inc/IL	CME	333.4	59.78	19,929.7	0.14%	3.85%	13.68%	0.01%	0.02%
CMS Energy Corp	CMS	265.9	26.40	7,020.7	0.05%	3.86%	6.00%	0.00%	0.00%
Coach Inc	COH	280.8	48.11	13,508.5	0.10%	2.57%	13.51%	0.00%	0.01%

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Coca-Cola Co/The	KO	4,456.7	38.66	172,296.7	1.23%	2.89%	8.23%	0.04%	0.10%
Coca-Cola Enterprises Inc	CCE	279.2	35.58	9,932.8	0.07%	2.25%	8.72%	0.00%	0.01%
Cognizant Technology Solutions Corp	CTSH	301.8	77.94	23,520.9	0.17%	0.00%	18.09%	0.00%	0.03%
Colgate-Palmolive Co	CL	472.5	114.01	53,867.6	0.39%	2.34%	9.02%	0.01%	0.03%
Comcast Corp	CMCSA	2,122.3	39.99	84,869.9	0.61%	1.93%	18.84%	0.01%	0.11%
Comerica Inc	CMA	187.7	34.45	6,465.2	0.05%	1.97%	6.64%	0.00%	0.00%
Computer Sciences Corp	CSC	155.2	48.24	7,486.9	0.05%	1.66%	8.00%	0.00%	0.00%
ConAgra Foods Inc	CAG	413.1	34.25	14,147.1	0.10%	2.90%	6.50%	0.00%	0.01%
ConocoPhillips	COP	1,221.0	58.17	71,025.2	0.51%	4.61%	5.48%	0.02%	0.03%
CONSOL Energy Inc	CNX	228.1	30.47	6,951.2	0.05%	1.64%	12.00%	0.00%	0.01%
Consolidated Edison Inc	ED	292.9	58.89	17,247.6	0.12%	4.17%	3.49%	0.01%	0.00%
Constellation Brands Inc	STZ	160.1	43.80	7,013.9	0.05%	0.00%	11.20%	0.00%	0.01%
Corning Inc	GLW	1,472.4	12.51	18,419.7	0.13%	2.90%	11.50%	0.00%	0.02%
Costco Wholesale Corp	COST	435.6	101.17	44,073.3	0.32%	6.37%	13.40%	0.02%	0.04%
Coventry Health Care Inc	CVH	134.6	45.54	6,129.9	0.04%	1.10%	12.33%	0.00%	0.01%
Covidien PLC	COV	472.0	63.51	29,979.5	0.21%	1.67%	8.65%	0.00%	0.02%
CR Bard Inc	BCR	81.8	98.84	8,084.5	0.06%	0.84%	8.50%	0.00%	0.00%
Crown Castle International Corp	CCI	293.2	70.14	20,562.2	0.15%	0.00%	36.45%	0.00%	0.05%
CSX Corp	CSX	1,020.8	22.95	23,427.3	0.17%	2.56%	12.67%	0.00%	0.02%
Cummins Inc	CMI	189.8	114.97	21,826.5	0.16%	1.81%	10.00%	0.00%	0.02%
CVS Caremark Corp	CVS	1,231.2	51.51	63,418.8	0.45%	1.66%	11.81%	0.01%	0.05%
Danaher Corp	DHR	690.2	61.52	42,463.9	0.30%	0.20%	14.50%	0.00%	0.04%
Darden Restaurants Inc	DRI	129.4	46.06	5,958.2	0.04%	4.41%	12.25%	0.00%	0.01%
DaVita HealthCare Partners Inc	DVA	95.4	119.96	11,444.2	0.08%	0.00%	12.29%	0.00%	0.01%
Dean Foods Co	DF	185.9	16.96	3,153.2	0.02%	0.00%	9.13%	0.00%	0.00%
Deere & Co	DE	389.6	87.83	34,214.7	0.25%	2.13%	9.25%	0.01%	0.02%
Dell Inc	DELL	1,738.6	14.00	24,331.7	0.17%	2.34%	8.33%	0.00%	0.01%
Delphi Automotive PLC	DLPH	315.3	42.21	13,308.8	0.10%	0.81%	12.88%	0.00%	0.01%
Denbury Resources Inc	DNR	387.0	17.92	6,935.0	0.05%	0.00%	9.10%	0.00%	0.00%
DENTSPLY International Inc	XRAY	142.8	41.12	5,874.0	0.04%	0.55%	11.50%	0.00%	0.00%
Devon Energy Corp	DVN	406.0	53.89	21,879.3	0.16%	1.35%	6.80%	0.00%	0.01%
Diamond Offshore Drilling Inc	DO	139.0	69.27	9,630.7	0.07%	5.05%	20.93%	0.00%	0.01%
DIRECTV	DTV	573.1	48.49	27,790.5	0.20%	0.00%	15.90%	0.00%	0.03%
Discover Financial Services	DFS	497.5	39.07	19,437.5	0.14%	1.42%	11.00%	0.00%	0.02%
Discovery Communications Inc	DISCA	145.1	74.75	10,847.4	0.08%	0.00%	19.70%	0.00%	0.02%
Dollar General Corp	DG	328.7	47.42	15,587.5	0.11%	0.00%	16.99%	0.00%	0.02%
Dollar Tree Inc	DLTR	227.2	45.98	10,446.9	0.07%	0.00%	15.98%	0.00%	0.01%
Dominion Resources Inc/VA	D	576.3	56.25	32,417.4	0.23%	3.97%	6.00%	0.01%	0.01%
Dover Corp	DOV	174.7	72.95	12,742.9	0.09%	1.98%	14.25%	0.00%	0.01%
Dow Chemical Co/The	DOW	1,204.4	31.77	38,262.6	0.27%	4.10%	6.50%	0.01%	0.02%
DR Horton Inc	DHI	321.3	22.50	7,229.8	0.05%	0.67%	7.67%	0.00%	0.00%
Dr Pepper Snapple Group Inc	DPS	203.6	43.75	8,908.9	0.06%	3.45%	7.38%	0.00%	0.00%
DTE Energy Co	DTE	172.5	66.33	11,445.0	0.08%	3.86%	5.00%	0.00%	0.00%
Duke Energy Corp	DUK	704.7	68.96	48,592.9	0.35%	4.49%	4.50%	0.02%	0.02%
Dun & Bradstreet Corp/The	DNB	40.9	80.44	3,287.9	0.02%	1.96%	n/a	0.00%	n/a
E*TRADE Financial Corp	ETFC	286.6	10.61	3,041.1	0.02%	0.00%	26.00%	0.00%	0.01%
Eastman Chemical Co	EMN	153.4	69.63	10,679.0	0.08%	1.58%	7.67%	0.00%	0.01%
Eaton Corp PLC	ETN	465.3	62.57	29,114.8	0.21%	2.70%	10.00%	0.01%	0.02%
eBay Inc	EBAY	1,296.5	54.96	71,256.3	0.51%	0.00%	13.38%	0.00%	0.07%
Ecolab Inc	ECL	295.0	76.74	22,634.8	0.16%	1.16%	13.50%	0.00%	0.02%
Edison International	EIX	325.8	48.49	15,798.6	0.11%	2.80%	7.22%	0.00%	0.01%
Edwards Lifesciences Corp	EW	114.1	85.70	9,778.4	0.07%	0.00%	17.68%	0.00%	0.01%
EI du Pont de Nemours & Co	DD	934.3	48.09	44,929.9	0.32%	3.59%	6.26%	0.01%	0.02%
Electronic Arts Inc	EA	300.1	18.06	5,417.9	0.04%	0.00%	14.80%	0.00%	0.01%
Eli Lilly & Co	LLY	1,134.4	54.83	62,199.8	0.45%	3.57%	1.00%	0.02%	0.00%
EMC Corp/MA	EMC	2,104.4	23.26	48,949.0	0.35%	0.00%	13.67%	0.00%	0.05%
Emerson Electric Co	EMR	722.1	56.00	40,436.1	0.29%	2.92%	10.17%	0.01%	0.03%
Ensco PLC	ESV	232.7	59.71	13,895.1	0.10%	2.74%	20.07%	0.00%	0.02%
Entergy Corp	ETR	178.1	62.04	11,048.9	0.08%	5.37%	4.67%	0.00%	0.00%
EOG Resources Inc	EOG	271.7	123.05	33,438.4	0.24%	0.58%	11.86%	0.00%	0.03%
EQT Corp	EQT	150.3	63.87	9,602.7	0.07%	0.49%	30.00%	0.00%	0.02%
Equifax Inc	EFX	120.5	55.86	6,728.5	0.05%	1.58%	11.00%	0.00%	0.01%

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Equity Residential	EQR	325.5	55.31	18,001.3	0.13%	3.42%	6.75%	0.00%	0.01%
Estee Lauder Cos Inc/The	EL	237.2	64.40	15,273.7	0.11%	1.54%	14.02%	0.00%	0.02%
Exelon Corp	EXC	855.0	30.93	26,445.7	0.19%	4.92%	-0.52%	0.01%	0.00%
Expedia Inc	EXPE	122.6	63.87	7,829.7	0.06%	0.69%	13.64%	0.00%	0.01%
Expeditors International of Washington Inc	EXPD	206.5	38.77	8,004.9	0.06%	1.58%	9.33%	0.00%	0.01%
Express Scripts Holding Co	ESRX	818.5	57.36	46,949.1	0.34%	0.00%	16.67%	0.00%	0.06%
Exxon Mobil Corp	XOM	4,480.5	89.34	400,283.4	2.87%	2.65%	3.08%	0.08%	0.09%
F5 Networks Inc	FFIV	78.6	93.62	7,357.7	0.05%	0.00%	18.43%	0.00%	0.01%
Family Dollar Stores Inc	FDO	115.8	58.58	6,783.9	0.05%	1.53%	10.79%	0.00%	0.01%
Fastenal Co	FAST	296.6	51.73	15,341.3	0.11%	0.95%	18.77%	0.00%	0.02%
FedEx Corp	FDX	314.5	105.37	33,134.8	0.24%	0.53%	11.14%	0.00%	0.03%
Fidelity National Information Services Inc	FIS	294.5	37.62	11,078.7	0.08%	2.34%	13.00%	0.00%	0.01%
Fifth Third Bancorp	FITB	882.2	15.84	13,968.9	0.10%	2.83%	7.84%	0.00%	0.01%
First Horizon National Corp	FHN	243.4	10.67	2,597.1	0.02%	1.41%	8.33%	0.00%	0.00%
First Solar Inc	FSLR	87.2	25.33	2,207.7	0.02%	0.00%	9.50%	0.00%	0.00%
FirstEnergy Corp	FE	418.2	39.42	16,486.1	0.12%	5.58%	2.20%	0.01%	0.00%
Fiserv Inc	FISV	133.5	81.41	10,868.5	0.08%	0.00%	11.71%	0.00%	0.01%
FLIR Systems Inc	FLIR	150.0	26.20	3,930.7	0.03%	1.37%	12.50%	0.00%	0.00%
Flowserve Corp	FLS	48.1	161.25	7,759.8	0.06%	1.02%	12.33%	0.00%	0.01%
Fluor Corp	FLR	162.5	60.50	9,831.7	0.07%	0.93%	13.43%	0.00%	0.01%
FMC Corp	FMC	137.7	59.76	8,227.2	0.06%	0.94%	11.57%	0.00%	0.01%
FMC Technologies Inc	FTI	237.5	51.48	12,225.4	0.09%	0.00%	15.33%	0.00%	0.01%
Ford Motor Co	F	3,851.4	12.60	48,527.6	0.35%	3.00%	8.62%	0.01%	0.03%
Forest Laboratories Inc	FRX	266.3	36.73	9,780.6	0.07%	0.00%	10.43%	0.00%	0.01%
Fossil Inc	FOSL	59.3	103.46	6,139.7	0.04%	0.00%	17.05%	0.00%	0.01%
Franklin Resources Inc	BEN	212.5	140.66	29,894.2	0.21%	2.96%	14.68%	0.01%	0.03%
Freeport-McMoRan Copper & Gold Inc	FCX	949.5	31.37	29,786.8	0.21%	3.98%	n/a	0.01%	n/a
Frontier Communications Corp	FTR	998.3	4.18	4,167.8	0.03%	9.58%	-2.22%	0.00%	0.00%
GameStop Corp	GME	121.2	23.97	2,904.7	0.02%	1.14%	11.80%	0.00%	0.00%
Gannett Co Inc	GCI	229.6	20.14	4,624.7	0.03%	4.17%	4.50%	0.00%	0.00%
Gap Inc/The	GPS	479.4	33.81	16,209.2	0.12%	1.50%	12.95%	0.00%	0.02%
Garmin Ltd	GRMN	208.1	35.12	7,307.7	0.05%	5.09%	7.39%	0.00%	0.00%
General Dynamics Corp	GD	353.7	67.69	23,940.2	0.17%	3.12%	5.56%	0.01%	0.01%
General Electric Co	GE	10,398.3	23.14	240,616.0	1.72%	3.36%	9.75%	0.06%	0.17%
General Mills Inc	GIS	646.6	46.35	29,969.7	0.21%	2.83%	8.00%	0.01%	0.02%
Genuine Parts Co	GPC	154.9	70.87	10,975.5	0.08%	3.03%	8.44%	0.00%	0.01%
Genworth Financial Inc	GNW	492.7	8.52	4,197.9	0.03%	0.00%	5.00%	0.00%	0.00%
Gilead Sciences Inc	GILD	1,522.4	43.43	66,117.5	0.47%	0.00%	22.85%	0.00%	0.11%
Goldman Sachs Group Inc/The	GS	465.5	150.31	69,969.8	0.50%	1.31%	10.57%	0.01%	0.05%
Goodyear Tire & Rubber Co/The	GT	245.4	12.95	3,176.7	0.02%	0.00%	24.04%	0.00%	0.01%
Google Inc	GOOG	267.5	805.82	215,556.9	1.54%	0.00%	14.76%	0.00%	0.23%
H&R Block Inc	HRB	271.3	24.76	6,717.2	0.05%	3.23%	11.00%	0.00%	0.01%
Halliburton Co	HAL	928.0	40.56	37,639.1	0.27%	1.17%	16.33%	0.00%	0.04%
Harley-Davidson Inc	HOG	226.2	52.04	11,774.0	0.08%	1.25%	13.00%	0.00%	0.01%
Harman International Industries Inc	HAR	67.9	42.44	2,883.2	0.02%	1.30%	17.50%	0.00%	0.00%
Harris Corp	HRS	112.8	47.72	5,385.2	0.04%	3.11%	4.00%	0.00%	0.00%
Hartford Financial Services Group Inc	HIG	436.3	23.65	10,318.7	0.07%	2.00%	9.00%	0.00%	0.01%
Hasbro Inc	HAS	128.7	40.01	5,151.1	0.04%	3.55%	9.00%	0.00%	0.00%
HCP Inc	HCP	453.4	48.88	22,161.2	0.16%	4.30%	3.66%	0.01%	0.01%
Health Care REIT Inc	HCN	260.4	64.60	16,824.0	0.12%	4.78%	5.48%	0.01%	0.01%
Helmerich & Payne Inc	HP	106.3	65.95	7,008.4	0.05%	0.78%	9.00%	0.00%	0.00%
Hershey Co/The	HSY	163.5	83.42	13,635.7	0.10%	2.00%	7.90%	0.00%	0.01%
Hess Corp	HES	341.5	66.27	22,634.3	0.16%	0.60%	6.31%	0.00%	0.01%
Hewlett-Packard Co	HPQ	1,948.1	20.20	39,352.6	0.28%	2.55%	5.33%	0.01%	0.02%
HJ Heinz Co	HNZ	320.7	72.47	23,237.6	0.17%	2.85%	7.00%	0.00%	0.01%
Home Depot Inc/The	HD	1,495.2	68.97	103,122.5	0.74%	2.28%	15.44%	0.02%	0.11%
Honeywell International Inc	HON	783.8	70.02	54,880.8	0.39%	2.36%	11.00%	0.01%	0.04%
Hormel Foods Corp	HRL	263.6	37.40	9,859.1	0.07%	1.70%	8.50%	0.00%	0.01%
Hospira Inc	HSP	165.2	29.45	4,865.7	0.03%	0.00%	8.92%	0.00%	0.00%
Host Hotels & Resorts Inc	HST	726.7	16.58	12,048.7	0.09%	2.50%	9.97%	0.00%	0.01%
Hudson City Bancorp Inc	HCBK	528.2	8.56	4,518.8	0.03%	3.74%	n/a	0.00%	n/a
Humana Inc	HUM	158.4	67.83	10,741.3	0.08%	1.57%	9.92%	0.00%	0.01%

Foward-Looking Market Risk Premium -- U.S.

Huntington Bancshares Inc/OH	HBAN	842.0	7.08	5,957.2	0.04%	2.60%	5.25%	0.00%	0.00%
Illinois Tool Works Inc	ITW	451.4	61.54	27,781.4	0.20%	2.43%	7.63%	0.00%	0.02%
Ingersoll-Rand PLC	IR	296.3	51.90	15,378.9	0.11%	1.64%	11.00%	0.00%	0.01%
Integrus Energy Group Inc	TEG	78.3	55.97	4,381.8	0.03%	4.86%	5.33%	0.00%	0.00%
Intel Corp	INTC	4,946.0	21.04	104,039.1	0.75%	4.34%	11.33%	0.03%	0.08%
IntercontinentalExchange Inc	ICE	72.7	153.81	11,174.7	0.08%	0.00%	13.45%	0.00%	0.01%
International Business Machines Corp	IBM	1,114.5	202.72	225,933.5	1.62%	1.69%	9.25%	0.03%	0.15%
International Flavors & Fragrances Inc	IFF	81.5	73.22	5,966.7	0.04%	1.85%	6.50%	0.00%	0.00%
International Game Technology	IGT	264.4	16.20	4,283.3	0.03%	1.60%	14.00%	0.00%	0.00%
International Paper Co	IP	441.2	44.23	19,514.6	0.14%	2.73%	5.50%	0.00%	0.01%
Interpublic Group of Cos Inc/The	IPG	413.9	12.79	5,293.9	0.04%	2.21%	9.67%	0.00%	0.00%
Intuit Inc	INTU	296.1	64.99	19,240.5	0.14%	1.04%	13.00%	0.00%	0.02%
Intuitive Surgical Inc	ISRG	40.1	551.96	22,148.5	0.16%	n/a	17.89%	n/a	0.03%
Invesco Ltd	IVZ	440.9	26.76	11,799.4	0.08%	2.84%	13.23%	0.00%	0.01%
Iron Mountain Inc	IRM	189.9	34.58	6,565.6	0.05%	3.17%	12.75%	0.00%	0.01%
Jabil Circuit Inc	JBL	202.1	18.49	3,737.6	0.03%	1.74%	12.00%	0.00%	0.00%
Jacobs Engineering Group Inc	JEC	130.4	47.93	6,247.8	0.04%	0.00%	10.23%	0.00%	0.00%
JC Penney Co Inc	JCP	219.4	17.73	3,890.0	0.03%	0.00%	17.10%	0.00%	0.00%
JDS Uniphase Corp	JDSU	229.8	14.10	3,240.3	0.02%	0.00%	12.00%	0.00%	0.00%
JM Smucker Co/The	SJM	108.5	96.14	10,427.7	0.07%	2.14%	7.33%	0.00%	0.01%
Johnson & Johnson	JNJ	2,795.3	76.67	214,317.1	1.53%	3.24%	6.88%	0.05%	0.11%
Johnson Controls Inc	JCI	684.3	31.48	21,542.4	0.15%	2.36%	12.79%	0.00%	0.02%
Joy Global Inc	JOY	106.0	61.99	6,570.6	0.05%	1.13%	9.43%	0.00%	0.00%
JPMorgan Chase & Co	JPM	3,804.0	48.92	186,091.7	1.33%	2.85%	6.69%	0.04%	0.09%
Juniper Networks Inc	JNPR	509.4	20.48	10,433.1	0.07%	0.00%	13.50%	0.00%	0.01%
Kellogg Co	K	361.9	60.46	21,879.9	0.16%	2.99%	7.93%	0.00%	0.01%
KeyCorp	KEY	923.9	9.35	8,638.1	0.06%	2.64%	5.00%	0.00%	0.00%
Kimberly-Clark Corp	KMB	387.6	94.39	36,587.6	0.26%	3.34%	7.91%	0.01%	0.02%
Kimco Realty Corp	KIM	407.9	21.76	8,875.5	0.06%	3.84%	6.45%	0.00%	0.00%
Kinder Morgan Inc/DE	KMI	1,036.7	37.18	38,545.0	0.28%	4.24%	7.00%	0.01%	0.02%
KLA-Tencor Corp	KLAC	166.1	54.47	9,049.9	0.06%	2.88%	10.00%	0.00%	0.01%
Kohl's Corp	KSS	230.0	46.09	10,601.2	0.08%	2.91%	9.08%	0.00%	0.01%
Kraft Foods Group Inc	KRFT	592.5	48.50	28,738.3	0.21%	3.43%	3.50%	0.01%	0.01%
Kroger Co/The	KR	518.4	29.46	15,273.1	0.11%	1.77%	10.05%	0.00%	0.01%
L-3 Communications Holdings Inc	LLL	89.9	76.34	6,862.7	0.05%	2.82%	0.63%	0.00%	0.00%
Laboratory Corp of America Holdings	LH	94.6	89.06	8,425.1	0.06%	0.00%	11.50%	0.00%	0.01%
Lam Research Corp	LRCX	162.3	42.70	6,932.2	0.05%	0.00%	11.00%	0.00%	0.01%
Legg Mason Inc	LM	129.0	28.25	3,643.0	0.03%	1.58%	14.63%	0.00%	0.00%
Leggett & Platt Inc	LEG	142.1	30.66	4,356.8	0.03%	3.65%	15.00%	0.00%	0.00%
Lennar Corp	LEN	160.7	38.74	6,224.6	0.04%	0.37%	8.00%	0.00%	0.00%
Leucadia National Corp	LUK	244.6	26.51	6,483.9	0.05%	n/a	n/a	n/a	n/a
Life Technologies Corp	LIFE	170.4	59.78	10,185.7	0.07%	0.00%	8.68%	0.00%	0.01%
Lincoln National Corp	LNC	275.0	29.70	8,168.0	0.06%	1.57%	10.00%	0.00%	0.01%
Linear Technology Corp	LLTC	232.6	37.92	8,818.9	0.06%	2.69%	10.07%	0.00%	0.01%
Lockheed Martin Corp	LMT	322.6	88.07	28,409.9	0.20%	5.27%	6.60%	0.01%	0.01%
Loews Corp	L	391.9	43.10	16,890.3	0.12%	0.58%	n/a	0.00%	n/a
Lorillard Inc	LO	379.4	38.25	14,510.5	0.10%	5.65%	9.32%	0.01%	0.01%
Lowe's Cos Inc	LOW	1,110.0	38.47	42,701.7	0.31%	1.82%	16.38%	0.01%	0.05%
LSI Corp	LSI	549.7	6.88	3,779.5	0.03%	n/a	15.33%	n/a	0.00%
Ltd Brands Inc	LTD	288.4	44.95	12,962.3	0.09%	3.27%	10.75%	0.00%	0.01%
LyondellBasell Industries NV	LYB	575.3	59.43	34,190.3	0.24%	2.76%	9.50%	0.01%	0.02%
M&T Bank Corp	MTB	128.7	102.57	13,203.6	0.09%	2.75%	16.54%	0.00%	0.02%
Macy's Inc	M	387.7	40.64	15,756.1	0.11%	2.09%	9.43%	0.00%	0.01%
Marathon Oil Corp	MRO	707.7	32.94	23,311.9	0.17%	2.11%	17.64%	0.00%	0.03%
Marathon Petroleum Corp	MPC	331.4	84.91	28,142.1	0.20%	1.85%	7.59%	0.00%	0.02%
Marriott International Inc/DE	MAR	315.5	39.53	12,473.3	0.09%	1.37%	14.73%	0.00%	0.01%
Marsh & McLennan Cos Inc	MMC	548.4	37.15	20,372.1	0.15%	2.49%	12.00%	0.00%	0.02%
Masco Corp	MAS	356.6	19.17	6,835.4	0.05%	1.58%	10.00%	0.00%	0.00%
Mastercard Inc	MA	118.0	518.08	61,113.6	0.44%	0.26%	19.00%	0.00%	0.08%
Mattel Inc	MAT	344.5	40.45	13,935.5	0.10%	3.40%	9.00%	0.00%	0.01%
McCormick & Co Inc/MD	MKC	120.2	68.35	8,217.8	0.06%	1.99%	n/a	0.00%	n/a
McDonald's Corp	MCD	1,002.8	95.55	95,816.8	0.69%	3.30%	9.89%	0.02%	0.07%

Foward-Looking Market Risk Premium -- U.S.

McGraw-Hill Cos Inc/The	MHP	280.8	47.19	13,251.0	0.09%	2.30%	8.50%	0.00%	0.01%
McKesson Corp	MCK	232.9	107.40	25,012.3	0.18%	0.72%	13.25%	0.00%	0.02%
Mead Johnson Nutrition Co	MJN	203.0	75.17	15,261.3	0.11%	1.79%	10.80%	0.00%	0.01%
MeadWestvaco Corp	MWV	175.7	35.62	6,257.3	0.04%	2.85%	10.00%	0.00%	0.00%
Medtronic Inc	MDT	1,011.4	45.18	45,693.2	0.33%	2.34%	7.73%	0.01%	0.03%
Merck & Co Inc	MRK	3,022.4	42.61	128,783.1	0.92%	4.00%	4.50%	0.04%	0.04%
MetLife Inc	MET	1,093.6	35.29	38,592.8	0.28%	2.90%	8.00%	0.01%	0.02%
MetroPCS Communications Inc	PCS	364.5	9.82	3,579.3	0.03%	0.00%	15.79%	0.00%	0.00%
Microchip Technology Inc	MCHP	195.4	36.44	7,119.0	0.05%	3.87%	n/a	0.00%	n/a
Micron Technology Inc	MU	1,021.8	8.26	8,434.8	0.06%	0.00%	14.04%	0.00%	0.01%
Microsoft Corp	MSFT	8,376.2	27.96	234,157.9	1.68%	3.25%	9.17%	0.05%	0.15%
Molex Inc	MOLX	95.6	27.73	2,649.9	0.02%	3.20%	12.50%	0.00%	0.00%
Molson Coors Brewing Co	TAP	156.8	45.16	7,079.9	0.05%	3.04%	7.67%	0.00%	0.00%
Mondelez International Inc	MDLZ	1,778.3	27.80	49,436.4	0.35%	1.90%	9.87%	0.01%	0.03%
Monsanto Co	MON	535.8	101.58	54,427.9	0.39%	1.27%	12.16%	0.00%	0.05%
Monster Beverage Corp	MNST	165.5	50.58	8,373.3	0.06%	0.00%	17.00%	0.00%	0.01%
Moody's Corp	MCO	223.6	48.88	10,929.6	0.08%	1.64%	15.00%	0.00%	0.01%
Morgan Stanley	MS	1,961.3	22.38	43,893.0	0.31%	1.09%	11.67%	0.00%	0.04%
Mosaic Co/The	MOS	296.9	58.39	17,337.8	0.12%	1.71%	6.32%	0.00%	0.01%
Motorola Solutions Inc	MSI	276.0	62.01	17,113.7	0.12%	1.86%	12.00%	0.00%	0.01%
Murphy Oil Corp	MUR	190.7	60.41	11,518.1	0.08%	2.06%	20.00%	0.00%	0.02%
Mylan Inc/PA	MYL	395.6	30.13	11,916.0	0.09%	0.00%	10.52%	0.00%	0.01%
Nabors Industries Ltd	NBR	290.4	16.45	4,776.8	0.03%	0.00%	9.00%	0.00%	0.00%
NASDAQ OMX Group Inc/The	NDAQ	165.7	31.52	5,222.2	0.04%	1.68%	11.52%	0.00%	0.00%
National Oilwell Varco Inc	NOV	426.6	66.95	28,563.5	0.20%	0.75%	11.33%	0.00%	0.02%
NetApp Inc	NTAP	360.4	33.97	12,243.0	0.09%	0.00%	12.83%	0.00%	0.01%
Netflix Inc	NFLX	56.0	189.13	10,590.0	0.08%	0.00%	25.20%	0.00%	0.02%
Newell Rubbermaid Inc	NWL	287.6	23.32	6,706.8	0.05%	2.62%	8.87%	0.00%	0.00%
Newfield Exploration Co	NFX	135.4	23.16	3,136.7	0.02%	0.00%	11.50%	0.00%	0.00%
Newmont Mining Corp	NEM	491.8	39.65	19,501.4	0.14%	4.59%	1.00%	0.01%	0.00%
News Corp	NWSA	1,568.8	29.11	45,668.2	0.33%	0.56%	13.00%	0.00%	0.04%
NextEra Energy Inc	NEE	423.2	72.23	30,568.2	0.22%	3.63%	5.33%	0.01%	0.01%
NIKE Inc	NKE	721.3	54.75	39,492.3	0.28%	1.48%	12.30%	0.00%	0.03%
NiSource Inc	NI	311.2	27.89	8,679.0	0.06%	3.54%	n/a	0.00%	n/a
Noble Corp	NE	253.2	35.39	8,961.7	0.06%	1.74%	13.67%	0.00%	0.01%
Noble Energy Inc	NBL	178.7	110.02	19,662.2	0.14%	0.86%	7.00%	0.00%	0.01%
Nordstrom Inc	JWN	197.0	54.05	10,647.9	0.08%	1.96%	12.25%	0.00%	0.01%
Norfolk Southern Corp	NSC	314.5	73.78	23,205.0	0.17%	2.73%	15.00%	0.00%	0.02%
Northeast Utilities	NU	314.3	41.74	13,120.5	0.09%	3.48%	7.82%	0.00%	0.01%
Northern Trust Corp	NTRS	239.2	53.20	12,723.2	0.09%	2.39%	14.63%	0.00%	0.01%
Northrop Grumman Corp	NOC	237.1	65.38	15,503.3	0.11%	3.57%	3.33%	0.00%	0.00%
NRG Energy Inc	NRG	323.2	23.95	7,739.8	0.06%	1.33%	n/a	0.00%	n/a
Nucor Corp	NUE	317.7	44.34	14,085.9	0.10%	3.31%	7.33%	0.00%	0.01%
NVIDIA Corp	NVDA	624.9	12.69	7,929.4	0.06%	2.39%	13.00%	0.00%	0.01%
NYSE Euronext	NYX	243.0	37.14	9,025.0	0.06%	3.23%	10.00%	0.00%	0.01%
O'Reilly Automotive Inc	ORLY	113.0	102.72	11,603.6	0.08%	0.00%	16.68%	0.00%	0.01%
Occidental Petroleum Corp	OXY	805.5	82.60	66,535.6	0.48%	2.82%	8.00%	0.01%	0.04%
Omnicom Group Inc	OMC	261.4	57.23	14,960.2	0.11%	2.69%	6.00%	0.00%	0.01%
ONEOK Inc	OKE	205.0	44.62	9,146.8	0.07%	3.38%	10.00%	0.00%	0.01%
Oracle Corp	ORCL	4,734.3	34.65	164,043.4	1.17%	0.74%	13.56%	0.01%	0.16%
Owens-Illinois Inc	OI	164.1	25.29	4,149.5	0.03%	0.00%	7.00%	0.00%	0.00%
PACCAR Inc	PCAR	353.5	46.87	16,567.1	0.12%	2.72%	10.25%	0.00%	0.01%
Pall Corp	PLL	111.1	67.46	7,494.2	0.05%	1.36%	14.26%	0.00%	0.01%
Parker Hannifin Corp	PH	149.2	94.34	14,071.6	0.10%	1.78%	7.57%	0.00%	0.01%
Patterson Cos Inc	PDCO	108.6	36.36	3,949.9	0.03%	1.56%	12.00%	0.00%	0.00%
Paychex Inc	PAYX	363.7	33.37	12,137.2	0.09%	3.90%	9.57%	0.00%	0.01%
Peabody Energy Corp	BTU	269.6	20.49	5,524.7	0.04%	1.68%	12.00%	0.00%	0.00%
Pentair Ltd	PNR	206.1	52.22	10,764.5	0.08%	1.78%	12.50%	0.00%	0.01%
People's United Financial Inc	PBCT	331.3	13.21	4,374.4	0.03%	4.85%	7.00%	0.00%	0.00%
Pepco Holdings Inc	POM	230.1	20.44	4,702.7	0.03%	5.28%	6.00%	0.00%	0.00%
PepsiCo Inc	PEP	1,542.8	75.81	116,958.4	0.84%	2.96%	7.66%	0.02%	0.06%
PerkinElmer Inc	PKI	113.7	34.62	3,937.5	0.03%	0.81%	10.65%	0.00%	0.00%

Foward-Looking Market Risk Premium -- U.S.

Perrigo Co	PRGO	93.5	113.00	10,570.8	0.08%	0.26%	11.86%	0.00%	0.01%
PetSmart Inc	PETM	107.5	64.66	6,949.3	0.05%	0.96%	18.08%	0.00%	0.01%
Pfizer Inc	PFE	7,189.1	27.40	196,980.3	1.41%	3.48%	3.81%	0.05%	0.05%
PG&E Corp	PCG	438.7	42.81	18,782.7	0.13%	4.28%	3.05%	0.01%	0.00%
Philip Morris International Inc	PM	1,647.8	91.55	150,855.1	1.08%	3.95%	11.51%	0.04%	0.12%
Phillips 66	PSX	625.8	63.73	39,882.6	0.29%	1.95%	7.50%	0.01%	0.02%
Pinnacle West Capital Corp	PNW	109.8	55.97	6,143.1	0.04%	3.95%	4.39%	0.00%	0.00%
Pioneer Natural Resources Co	PXD	133.7	123.84	16,558.7	0.12%	0.08%	15.98%	0.00%	0.02%
Pitney Bowes Inc	PBI	201.3	13.01	2,619.5	0.02%	11.45%	n/a	0.00%	n/a
Plum Creek Timber Co Inc	PCL	162.3	48.64	7,895.6	0.06%	3.45%	5.00%	0.00%	0.00%
PNC Financial Services Group Inc	PNC	528.0	62.66	33,084.5	0.24%	2.83%	3.64%	0.01%	0.01%
PPG Industries Inc	PPG	142.8	134.72	19,244.2	0.14%	1.78%	8.00%	0.00%	0.01%
PPL Corp	PPL	581.7	30.82	17,928.2	0.13%	4.75%	0.33%	0.01%	0.00%
Praxair Inc	PX	296.2	113.41	33,590.8	0.24%	2.11%	10.25%	0.01%	0.02%
Precision Castparts Corp	PCP	146.5	185.69	27,194.8	0.19%	0.07%	13.96%	0.00%	0.03%
priceline.com Inc	PCLN	49.9	694.94	34,657.3	0.25%	0.00%	18.17%	0.00%	0.05%
Principal Financial Group Inc	PFG	293.4	31.51	9,245.1	0.07%	2.86%	11.50%	0.00%	0.01%
Procter & Gamble Co/The	PG	2,731.7	76.48	208,916.7	1.50%	2.97%	8.83%	0.04%	0.13%
Progressive Corp/The	PGR	603.9	24.37	14,717.5	0.11%	1.58%	8.25%	0.00%	0.01%
Prologis Inc	PLD	462.8	39.23	18,155.9	0.13%	2.90%	4.83%	0.00%	0.01%
Prudential Financial Inc	PRU	463.0	54.96	25,446.5	0.18%	3.19%	12.00%	0.01%	0.02%
Public Service Enterprise Group Inc	PEG	506.0	32.75	16,570.2	0.12%	4.41%	0.67%	0.01%	0.00%
Public Storage	PSA	171.7	151.80	26,068.3	0.19%	3.18%	5.56%	0.01%	0.01%
PulteGroup Inc	PHM	386.6	19.21	7,426.6	0.05%	0.00%	10.00%	0.00%	0.01%
PVH Corp	PVH	81.0	121.80	9,865.8	0.07%	0.12%	14.18%	0.00%	0.01%
QEP Resources Inc	QEP	178.6	29.88	5,335.1	0.04%	0.27%	15.00%	0.00%	0.01%
QUALCOMM Inc	QCOM	1,718.1	66.41	114,101.0	0.82%	1.44%	15.14%	0.01%	0.12%
Quanta Services Inc	PWR	209.3	28.10	5,882.3	0.04%	n/a	20.67%	n/a	0.01%
Quest Diagnostics Inc	DGX	158.2	56.09	8,874.4	0.06%	1.88%	10.56%	0.00%	0.01%
Ralph Lauren Corp	RL	60.8	173.79	10,572.5	0.08%	0.88%	12.25%	0.00%	0.01%
Range Resources Corp	RRC	162.8	77.36	12,597.5	0.09%	0.19%	10.00%	0.00%	0.01%
Raytheon Co	RTN	326.4	54.63	17,828.8	0.13%	4.04%	9.00%	0.01%	0.01%
Red Hat Inc	RHT	193.2	51.63	9,974.6	0.07%	0.00%	17.00%	0.00%	0.01%
Regions Financial Corp	RF	1,413.4	7.69	10,869.0	0.08%	1.69%	8.00%	0.00%	0.01%
Republic Services Inc	RSG	362.6	31.13	11,287.6	0.08%	3.03%	2.30%	0.00%	0.00%
Reynolds American Inc	RAI	552.9	43.33	23,959.2	0.17%	5.77%	7.32%	0.01%	0.01%
Robert Half International Inc	RHI	139.6	35.11	4,899.6	0.04%	1.84%	14.33%	0.00%	0.01%
Rockwell Automation Inc	ROK	139.8	89.34	12,490.1	0.09%	2.13%	10.33%	0.00%	0.01%
Rockwell Collins Inc	COL	136.6	59.96	8,188.7	0.06%	2.01%	8.90%	0.00%	0.01%
Roper Industries Inc	ROP	98.9	124.81	12,342.6	0.09%	0.60%	15.00%	0.00%	0.01%
Ross Stores Inc	ROST	222.4	58.17	12,935.9	0.09%	1.02%	13.20%	0.00%	0.01%
Rowan Cos Plc	RDC	124.2	34.93	4,338.1	0.03%	0.03%	25.53%	0.00%	0.01%
Ryder System Inc	R	51.5	55.42	2,852.9	0.02%	2.21%	9.90%	0.00%	0.00%
Safeway Inc	SWY	239.6	23.96	5,740.8	0.04%	3.00%	10.60%	0.00%	0.00%
SAIC Inc	SAI	341.9	11.95	4,085.4	0.03%	4.04%	7.00%	0.00%	0.00%
Salesforce.com Inc	CRM	146.4	181.59	26,593.3	0.19%	0.00%	27.91%	0.00%	0.05%
SanDisk Corp	SNDK	241.8	50.28	12,160.1	0.09%	0.00%	19.01%	0.00%	0.02%
SCANA Corp	SCG	131.8	48.88	6,442.0	0.05%	4.13%	4.01%	0.00%	0.00%
Schlumberger Ltd	SLB	1,328.3	77.62	103,099.2	0.74%	1.58%	17.00%	0.01%	0.13%
Scripps Networks Interactive Inc	SNI	114.6	64.09	7,342.8	0.05%	0.79%	13.29%	0.00%	0.01%
Seagate Technology PLC	STX	358.9	32.38	11,619.9	0.08%	4.46%	6.09%	0.00%	0.01%
Sealed Air Corp	SEE	194.5	22.37	4,351.3	0.03%	2.29%	5.50%	0.00%	0.00%
Sempra Energy	SRE	243.3	78.26	19,039.9	0.14%	3.23%	7.00%	0.00%	0.01%
Sherwin-Williams Co/The	SHW	103.4	162.19	16,770.8	0.12%	1.08%	11.09%	0.00%	0.01%
Sigma-Aldrich Corp	SIAL	120.4	77.34	9,315.2	0.07%	1.11%	6.64%	0.00%	0.00%
Simon Property Group Inc	SPG	313.7	159.78	50,117.3	0.36%	2.95%	7.15%	0.01%	0.03%
SLM Corp	SLM	453.3	19.68	8,921.8	0.06%	2.91%	-4.30%	0.00%	0.00%
Snap-on Inc	SNA	58.3	79.47	4,630.8	0.03%	n/a	10.00%	n/a	0.00%
Southern Co/The	SO	869.0	44.75	38,886.4	0.28%	4.50%	5.28%	0.01%	0.01%
Southwest Airlines Co	LUV	728.1	11.82	8,606.1	0.06%	0.21%	15.16%	0.00%	0.01%
Southwestern Energy Co	SWN	351.1	35.13	12,334.1	0.09%	0.00%	n/a	0.00%	n/a
Spectra Energy Corp	SE	668.1	28.79	19,235.5	0.14%	4.31%	5.50%	0.01%	0.01%

Foward-Looking Market Risk Premium -- U.S.

Sprint Nextel Corp	S	3,004.6	5.79	17,396.7	0.12%	0.00%	5.50%	0.00%	0.01%
St Jude Medical Inc	STJ	282.9	41.33	11,691.1	0.08%	2.39%	10.17%	0.00%	0.01%
Stanley Black & Decker Inc	SWK	160.3	77.52	12,422.6	0.09%	2.53%	12.50%	0.00%	0.01%
Staples Inc	SPLS	673.9	12.97	8,740.2	0.06%	3.32%	8.50%	0.00%	0.01%
Starbucks Corp	SBUX	749.3	54.81	41,069.1	0.29%	1.56%	18.49%	0.00%	0.05%
Starwood Hotels & Resorts Worldwide Inc	HOT	196.0	60.43	11,842.9	0.08%	2.05%	12.47%	0.00%	0.01%
State Street Corp	STT	456.9	56.30	25,722.4	0.18%	1.94%	11.14%	0.00%	0.02%
Stericycle Inc	SRCL	86.1	95.97	8,262.0	0.06%	n/a	16.00%	n/a	0.01%
Stryker Corp	SYK	380.5	64.76	24,642.0	0.18%	1.53%	9.88%	0.00%	0.02%
SunTrust Banks Inc	STI	538.9	27.52	14,831.7	0.11%	1.74%	8.25%	0.00%	0.01%
Symantec Corp	SYMC	689.2	23.62	16,278.6	0.12%	0.00%	7.14%	0.00%	0.01%
Sysco Corp	SYU	586.0	32.44	19,009.5	0.14%	3.46%	8.07%	0.00%	0.01%
T Rowe Price Group Inc	TROW	257.9	71.62	18,467.3	0.13%	2.07%	14.15%	0.00%	0.02%
Target Corp	TGT	645.3	64.03	41,318.6	0.30%	2.32%	11.75%	0.01%	0.03%
TE Connectivity Ltd	TEL	420.3	40.16	16,877.7	0.12%	2.27%	15.00%	0.00%	0.02%
TECO Energy Inc	TE	217.3	17.31	3,760.7	0.03%	5.12%	3.67%	0.00%	0.00%
Tenet Healthcare Corp	THC	104.3	39.43	4,112.0	0.03%	0.00%	11.00%	0.00%	0.00%
Teradata Corp	TDC	165.8	58.67	9,727.5	0.07%	0.00%	16.00%	0.00%	0.01%
Teradyne Inc	TER	187.9	16.61	3,120.2	0.02%	1.20%	11.75%	0.00%	0.00%
Tesoro Corp	TSO	140.4	58.17	8,169.1	0.06%	1.26%	38.82%	0.00%	0.02%
Texas Instruments Inc	TXN	1,104.8	34.41	38,010.2	0.27%	2.64%	9.33%	0.01%	0.03%
Textron Inc	TXT	271.5	28.51	7,741.7	0.06%	0.31%	15.61%	0.00%	0.01%
Thermo Fisher Scientific Inc	TMO	360.2	74.68	26,900.8	0.19%	0.80%	10.51%	0.00%	0.02%
Tiffany & Co	TIF	126.8	69.05	8,753.8	0.06%	1.82%	14.32%	0.00%	0.01%
Time Warner Cable Inc	TWC	295.5	88.45	26,138.2	0.19%	2.95%	12.80%	0.01%	0.02%
Time Warner Inc	TWX	934.8	53.46	49,973.9	0.36%	2.13%	10.52%	0.01%	0.04%
TJX Cos Inc	TJX	729.3	44.88	32,728.9	0.23%	1.25%	11.64%	0.00%	0.03%
Torchmark Corp	TMK	93.7	56.25	5,268.2	0.04%	1.16%	9.00%	0.00%	0.00%
Total System Services Inc	TSS	186.6	23.75	4,431.4	0.03%	1.64%	10.50%	0.00%	0.00%
Travelers Cos Inc/The	TRV	378.0	80.58	30,455.6	0.22%	2.37%	6.48%	0.01%	0.01%
TripAdvisor Inc	TRIP	130.1	45.57	5,928.9	0.04%	n/a	16.34%	n/a	0.01%
Tyco International Ltd	TYC	466.0	31.65	14,749.5	0.11%	1.99%	11.00%	0.00%	0.01%
Tyson Foods Inc	TSN	284.5	23.12	6,578.1	0.05%	1.03%	8.50%	0.00%	0.00%
Union Pacific Corp	UNP	469.3	136.53	64,073.4	0.46%	2.03%	12.65%	0.01%	0.06%
United Parcel Service Inc	UPS	730.4	82.83	60,495.5	0.43%	2.94%	9.73%	0.01%	0.04%
United States Steel Corp	X	144.3	20.21	2,915.9	0.02%	0.99%	6.00%	0.00%	0.00%
United Technologies Corp	UTX	916.6	90.03	82,525.1	0.59%	2.45%	12.15%	0.01%	0.07%
UnitedHealth Group Inc	UNH	1,024.9	53.46	54,792.5	0.39%	1.66%	11.50%	0.01%	0.05%
Unum Group	UNM	269.8	24.57	6,628.9	0.05%	2.25%	9.50%	0.00%	0.00%
Urban Outfitters Inc	URBN	145.9	40.75	5,945.9	0.04%	0.00%	18.67%	0.00%	0.01%
US Bancorp	USB	1,863.4	34.01	63,373.7	0.45%	2.61%	8.06%	0.01%	0.04%
Valero Energy Corp	VLO	553.5	46.68	25,839.3	0.19%	1.63%	7.85%	0.00%	0.01%
Varian Medical Systems Inc	VAR	109.1	70.83	7,728.5	0.06%	0.00%	11.75%	0.00%	0.01%
Ventas Inc	VTR	291.9	71.23	20,795.2	0.15%	3.76%	5.99%	0.01%	0.01%
VeriSign Inc	VRSN	155.3	46.10	7,157.3	0.05%	0.00%	13.80%	0.00%	0.01%
Verizon Communications Inc	VZ	2,858.3	46.67	133,395.7	0.96%	4.45%	7.15%	0.04%	0.07%
VF Corp	VFC	110.2	160.50	17,692.4	0.13%	2.20%	12.82%	0.00%	0.02%
Viacom Inc	VIAB	443.8	59.66	26,477.6	0.19%	1.91%	12.67%	0.00%	0.02%
Visa Inc	V	529.4	158.39	83,849.1	0.60%	0.80%	18.88%	0.00%	0.11%
Vornado Realty Trust	VNO	186.7	80.09	14,955.6	0.11%	3.62%	-2.56%	0.00%	0.00%
Vulcan Materials Co	VMC	129.9	51.89	6,739.1	0.05%	0.08%	9.67%	0.00%	0.00%
Wal-Mart Stores Inc	WMT	3,340.0	71.78	239,745.2	1.72%	2.59%	9.87%	0.04%	0.17%
Walgreen Co	WAG	945.1	41.26	38,995.0	0.28%	2.46%	12.31%	0.01%	0.03%
Walt Disney Co/The	DIS	1,805.4	55.31	99,858.7	0.72%	1.24%	12.14%	0.01%	0.09%
Washington Post Co/The	WPO	6.2	394.02	2,444.6	0.02%	n/a	n/a	n/a	n/a
Waste Management Inc	WM	465.2	36.84	17,138.0	0.12%	4.00%	3.10%	0.00%	0.00%
Waters Corp	WAT	85.9	93.69	8,046.7	0.06%	0.00%	9.57%	0.00%	0.01%
WellPoint Inc	WLP	304.0	61.88	18,813.7	0.13%	1.93%	10.83%	0.00%	0.01%
Wells Fargo & Co	WFC	5,270.9	35.41	186,641.9	1.34%	2.87%	11.08%	0.04%	0.15%
Western Digital Corp	WDC	240.7	48.16	11,590.4	0.08%	1.92%	2.49%	0.00%	0.00%
Western Union Co/The	WU	568.8	14.28	8,122.0	0.06%	3.49%	11.00%	0.00%	0.01%
Weyerhaeuser Co	WY	541.5	29.51	15,980.6	0.11%	2.31%	5.33%	0.00%	0.01%

Foward-Looking Market Risk Premium -- U.S.

Whirlpool Corp	WHR	78.5	114.22	8,971.2	0.06%	1.75%	n/a	0.00%	n/a
Whole Foods Market Inc	WFM	185.3	85.67	15,877.4	0.11%	2.83%	18.09%	0.00%	0.02%
Williams Cos Inc/The	WMB	681.5	33.89	23,097.1	0.17%	4.29%	13.00%	0.01%	0.02%
Windstream Corp	WIN	590.5	8.70	5,137.2	0.04%	11.49%	-1.99%	0.00%	0.00%
Wisconsin Energy Corp	WEC	229.0	41.28	9,453.3	0.07%	3.28%	4.80%	0.00%	0.00%
WPX Energy Inc	WPX	200.1	14.45	2,891.9	0.02%	n/a	n/a	n/a	n/a
WW Grainger Inc	GWV	69.5	227.59	15,822.7	0.11%	1.50%	15.03%	0.00%	0.02%
Wyndham Worldwide Corp	WYN	136.6	60.49	8,265.0	0.06%	1.92%	19.60%	0.00%	0.01%
Wynn Resorts Ltd	WYNN	100.6	116.43	11,710.7	0.08%	3.44%	9.00%	0.00%	0.01%
Xcel Energy Inc	XEL	488.3	28.66	13,994.2	0.10%	3.86%	5.00%	0.00%	0.01%
Xerox Corp	XRX	1,223.8	8.15	9,974.3	0.07%	2.53%	10.00%	0.00%	0.01%
Xilinx Inc	XLNX	261.6	36.70	9,598.0	0.07%	2.39%	12.75%	0.00%	0.01%
XL Group PLC	XL	295.0	28.77	8,485.9	0.06%	1.65%	7.50%	0.00%	0.00%
Xylem Inc/NY	XYL	186.2	27.48	5,115.7	0.04%	1.69%	5.00%	0.00%	0.00%
Yahoo! Inc	YHOO	1,182.7	21.90	25,895.0	0.19%	0.00%	13.83%	0.00%	0.03%
Yum! Brands Inc	YUM	450.7	65.03	29,310.9	0.21%	2.12%	12.18%	0.00%	0.03%
Zimmer Holdings Inc	ZMH	169.4	74.89	12,682.9	0.09%	0.71%	10.65%	0.00%	0.01%
Zions Bancorporation	ZION	184.2	24.05	4,429.7	0.03%	0.63%	7.75%	0.00%	0.00%

Notes:

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- [1] Equals sum of column [14]
 [2] Equals sum of column [15]
 [3] Equals [1] x (1 + 0.5 x [2]) + [2]
 [4] Source: Equals average long-term Consensus Forecast of 10-year Canadian government bond yield for the period 2013-2022
 [5] Equals 30-day average spread between 10- and 30-year Canadian government bond ending February 28, 2013.
 [6] Equals [5] + [6]
 [7] Equals [3]+[6]
 [8] Source: Bloomberg
 [9] Source: Bloomberg
 [10] Equals [8] x [9]
 [11] Equals [10] / sum of column [10]
 [12] Source: Bloomberg
 [13] Source: Bloomberg
 [14] Equals [11] x [12]
 [15] Equals [11] x [13]

Foward-Looking Market Risk Premium -- Canada

[1] Estimated Weighted Average Dividend Yield	3.06%
[2] Estimated Weighted Average Long-Term Growth Rate	7.19%
[3] TSX Estimated Required Market Return	10.36%
[4] 10-Year Government Bond Yield Forecast (2013-2022)	3.62%
[5] Credit Spread between 10- and 30-Year Bond Yield	0.61%
[6] Risk-Free Rate	4.23%
[7] Implied Market Risk Premium	6.14%

Company Name	Ticker	[8] Shares Outstanding	[9] Price	[10] Market Cap.	[11] Weight	[12] Div. Yld.	[13] Earnings Growth	[14] Div. Yld. x Weight	[15] Earn. Gr. x Weight
Advantage Oil & Gas Ltd	AAV	168.4	3.12	525.4	0.03%	0.00%	n/a	0.00%	n/a
Aecon Group Inc	ARE	55.8	12.18	679.8	0.04%	2.03%	10.00%	0.00%	0.00%
AGF Management Ltd	AGF/B	89.2	11.82	1,054.3	0.06%	9.14%	n/a	0.01%	n/a
Agnico-Eagle Mines Ltd	AEM	172.5	41.23	7,112.1	0.41%	2.06%	16.50%	0.01%	0.07%
Agrium Inc	AGU	149.4	107.33	16,030.7	0.93%	1.73%	16.23%	0.02%	0.15%
Aimia Inc	AIM	172.3	15.60	2,688.5	0.16%	4.15%	n/a	0.01%	n/a
Alacer Gold Corp	ASR	286.9	3.40	975.4	0.06%	0.00%	12.37%	0.00%	0.01%
Alamos Gold Inc	AGI	127.5	14.19	1,808.6	0.11%	1.45%	19.46%	0.00%	0.02%
Algonquin Power & Utilities Corp	AQN	200.5	7.75	1,553.9	0.09%	3.87%	n/a	0.00%	n/a
Alimentation Couche Tard Inc	ATD/B	138.1	52.86	7,301.4	0.42%	0.56%	12.00%	0.00%	0.05%
Allied Properties Real Estate Investment Trust	AP-U	64.1	34.11	2,188.0	0.13%	3.87%	n/a	0.00%	n/a
AltaGas Ltd	ALA	105.6	35.45	3,744.1	0.22%	4.12%	n/a	0.01%	n/a
ARC Resources Ltd	ARX	309.4	26.15	8,089.7	0.47%	4.59%	n/a	0.02%	n/a
Argonaut Gold Inc	AR	148.6	8.02	1,192.0	0.07%	n/a	71.00%	n/a	0.05%
Artis Real Estate Investment Trust	AX-U	120.3	15.98	1,922.2	0.11%	6.78%	n/a	0.01%	n/a
Astral Media Inc	ACM/A	53.4	48.01	2,564.9	0.15%	2.08%	n/a	0.00%	n/a
Atco Ltd/Canada	ACO/X	50.7	90.50	4,586.5	0.27%	1.66%	n/a	0.00%	n/a
Athabasca Oil Corp	ATH	400.5	9.86	3,949.0	0.23%	n/a	-229.00%	n/a	-0.53%
Atlantic Power Corp	ATP	119.5	7.30	872.3	0.05%	13.07%	n/a	0.01%	n/a
AuRico Gold Inc	AUQ	246.4	6.38	1,572.0	0.09%	0.00%	5.00%	0.00%	0.00%
Aurizon Mines Ltd	ARZ	164.6	4.37	719.1	0.04%	0.00%	8.38%	0.00%	0.00%
B2Gold Corp	BTO	645.6	3.02	1,949.8	0.11%	n/a	n/a	n/a	n/a
Bank of Montreal	BMO	652.0	63.96	41,702.6	2.43%	4.59%	7.00%	0.11%	0.17%
Bank of Nova Scotia	BNS	1,191.9	61.10	72,823.7	4.24%	3.85%	8.33%	0.16%	0.35%
Bankers Petroleum Ltd	BNK	253.9	3.06	776.8	0.05%	n/a	n/a	n/a	n/a
Banro Corp	BAA	201.9	2.19	442.1	0.03%	0.47%	n/a	0.00%	n/a
Barrick Gold Corp	ABX	1,001.1	30.17	30,203.4	1.76%	2.66%	-4.00%	0.05%	-0.07%
Baytex Energy Corp	BTE	122.4	43.53	5,329.6	0.31%	6.07%	n/a	0.02%	n/a
BCE Inc	BCE	775.4	46.58	36,117.3	2.10%	5.00%	1.75%	0.11%	0.04%
Bell Aliant Inc	BA	227.8	26.92	6,132.9	0.36%	7.06%	3.00%	0.03%	0.01%
Birchcliff Energy Ltd	BIR	141.8	7.82	1,109.0	0.06%	n/a	n/a	n/a	n/a
Black Diamond Group Ltd	BDI	41.4	21.32	883.0	0.05%	3.28%	n/a	0.00%	n/a
BlackPearl Resources Inc	PXX	296.1	2.47	731.4	0.04%	0.00%	n/a	0.00%	n/a
Boardwalk Real Estate Investment Trust	BEI-U	47.9	65.14	3,117.5	0.18%	3.04%	n/a	0.01%	n/a
Bombardier Inc	BBD/B	1,440.4	4.10	5,905.7	0.34%	2.13%	10.81%	0.01%	0.04%
Bonavista Energy Corp	BNP	178.7	13.71	2,450.6	0.14%	6.24%	n/a	0.01%	n/a
Bonterra Energy Corp	BNE	30.6	48.43	1,483.0	0.09%	6.51%	n/a	0.01%	n/a
Brookfield Asset Management Inc	BAM/A	625.2	39.50	24,694.2	1.44%	1.52%	n/a	0.02%	n/a
Brookfield Office Properties Inc	BPO	505.0	17.20	8,685.5	0.51%	3.37%	n/a	0.02%	n/a
CAE Inc	CAE	259.7	10.10	2,622.9	0.15%	1.72%	12.05%	0.00%	0.02%
Calfrac Well Services Ltd	CFW	45.2	25.15	1,135.6	0.07%	4.06%	23.10%	0.00%	0.02%
Calloway Real Estate Investment Trust	CWT-U	114.1	29.05	3,315.7	0.19%	5.35%	n/a	0.01%	n/a
Cameco Corp	CCO	395.4	21.45	8,480.3	0.49%	1.86%	19.96%	0.01%	0.10%
Canadian Apartment Properties REIT	CAR-U	101.8	25.32	2,578.1	0.15%	4.45%	n/a	0.01%	n/a
Canadian Imperial Bank of Commerce/Canada	CM	402.0	82.92	33,330.6	1.94%	4.61%	6.67%	0.09%	0.13%
Canadian National Railway Co	CNR	428.4	103.90	44,507.7	2.59%	1.66%	13.80%	0.04%	0.36%
Canadian Natural Resources Ltd	CNQ	1,092.3	32.17	35,140.0	2.04%	1.30%	6.00%	0.03%	0.12%
Canadian Oil Sands Ltd	COS	484.6	20.96	10,156.3	0.59%	6.67%	-9.00%	0.04%	-0.05%

Foward-Looking Market Risk Premium -- Canada

Canadian Pacific Railway Ltd	CP	174.2	126.93	22,111.5	1.29%	1.15%	11.75%	0.01%	0.15%
Canadian Real Estate Investment Trust	REF-U	68.3	46.77	3,193.6	0.19%	3.31%	n/a	0.01%	n/a
Canadian Tire Corp Ltd	CTC/A	77.7	69.28	5,384.5	0.31%	2.05%	5.41%	0.01%	0.02%
Canadian Utilities Ltd	CU	88.3	78.18	6,906.9	0.40%	2.48%	n/a	0.01%	n/a
Canadian Western Bank	CWB	79.0	30.69	2,424.3	0.14%	2.24%	10.00%	0.00%	0.01%
Canexus Corp	CUS	135.3	9.42	1,274.5	0.07%	5.84%	n/a	0.00%	n/a
Canfor Corp	CFP	142.8	19.25	2,748.0	0.16%	n/a	n/a	n/a	n/a
Capital Power Corp	CPX	70.3	23.10	1,622.9	0.09%	5.45%	n/a	0.01%	n/a
Capstone Mining Corp	CS	380.0	2.34	889.2	0.05%	0.00%	5.00%	0.00%	0.00%
Catamaran Corp	CCT	205.5	56.44	11,596.3	0.67%	0.00%	25.50%	0.00%	0.17%
CCL Industries Inc	CCL/B	31.5	61.00	1,918.5	0.11%	1.41%	n/a	0.00%	n/a
Celestica Inc	CLS	164.1	8.47	1,389.6	0.08%	0.00%	10.00%	0.00%	0.01%
Cenovus Energy Inc	CVE	755.1	32.72	24,706.6	1.44%	2.90%	11.00%	0.04%	0.16%
Centerra Gold Inc	CG	236.4	6.49	1,534.1	0.09%	2.76%	4.00%	0.00%	0.00%
CGI Group Inc	GIB/A	274.6	27.01	7,417.5	0.43%	n/a	10.00%	n/a	0.04%
Chartwell Retirement Residences	CSH-U	171.9	10.95	1,882.1	0.11%	4.93%	n/a	0.01%	n/a
China Gold International Resources Corp Ltd	CGG	396.4	3.14	1,242.6	0.07%	0.43%	n/a	0.00%	n/a
Chorus Aviation Inc	CHR/B	108.7	3.89	422.9	0.02%	15.42%	n/a	0.00%	n/a
CI Financial Corp	CIX	283.2	26.93	7,626.5	0.44%	3.76%	n/a	0.02%	n/a
Cineplex Inc	CGX	62.8	33.86	2,125.8	0.12%	4.11%	n/a	0.01%	n/a
CML HealthCare Inc	CLC	90.0	7.34	660.5	0.04%	10.22%	-11.00%	0.00%	0.00%
Cogeco Cable Inc	CCA	33.1	43.04	1,425.6	0.08%	2.59%	14.94%	0.00%	0.01%
Colossus Minerals Inc	CSI	106.6	2.75	293.1	0.02%	0.00%	n/a	0.00%	n/a
Cominar Real Estate Investment Trust	CUF-U	124.3	22.47	2,794.1	0.16%	6.41%	n/a	0.01%	n/a
Constellation Software Inc/Canada	CSU	21.2	120.27	2,548.7	0.15%	3.42%	n/a	0.01%	n/a
Corus Entertainment Inc	CJR/B	80.4	25.55	2,053.6	0.12%	3.95%	5.80%	0.00%	0.01%
Cott Corp	BCB	95.4	9.74	928.9	0.05%	1.03%	n/a	0.00%	n/a
Crescent Point Energy Corp	CPG	377.5	38.64	14,585.4	0.85%	7.14%	n/a	0.06%	n/a
Crew Energy Inc	CR	121.6	6.48	788.1	0.05%	n/a	n/a	n/a	n/a
Crombie Real Estate Investment Trust	CRR-U	53.4	14.65	781.7	0.05%	6.08%	n/a	0.00%	n/a
Davis + Henderson Corp	DH	59.2	21.86	1,294.8	0.08%	5.90%	n/a	0.00%	n/a
Detour Gold Corp	DGC	117.9	19.55	2,304.8	0.13%	0.00%	5.00%	0.00%	0.01%
Dollarama Inc	DOL	73.1	60.19	4,399.3	0.26%	0.78%	n/a	0.00%	n/a
Dorel Industries Inc	DII/B	27.4	36.77	1,007.9	0.06%	2.31%	16.00%	0.00%	0.01%
Dundee Corp	DC/A	50.9	33.95	1,729.6	0.10%	n/a	n/a	n/a	n/a
Dundee Precious Metals Inc	DPM	125.7	7.49	941.3	0.05%	0.00%	n/a	0.00%	n/a
Dundee Real Estate Investment Trust	D-U	97.7	36.55	3,571.1	0.21%	6.10%	n/a	0.01%	n/a
Eldorado Gold Corp	ELD	714.5	10.25	7,323.5	0.43%	1.78%	65.50%	0.01%	0.28%
Emera Inc	EMA	131.0	35.93	4,706.0	0.27%	3.92%	n/a	0.01%	n/a
Empire Co Ltd	EMP/A	33.7	64.95	2,188.0	0.13%	1.48%	7.00%	0.00%	0.01%
Enbridge Inc	ENB	806.2	46.00	37,087.4	2.16%	2.76%	11.50%	0.06%	0.25%
Enbridge Income Fund Holdings Inc	ENF	56.5	25.18	1,422.4	0.08%	5.32%	n/a	0.00%	n/a
Encana Corp	ECA	735.4	18.32	13,473.4	0.78%	4.49%	29.00%	0.04%	0.23%
Endeavour Silver Corp	EDR	99.7	5.72	570.2	0.03%	n/a	n/a	n/a	n/a
Enerflex Ltd	EFX	77.7	12.75	990.7	0.06%	2.10%	n/a	0.00%	n/a
Enerplus Corp	ERF	198.9	14.14	2,813.0	0.16%	7.64%	n/a	0.01%	n/a
Ensign Energy Services Inc	ESI	153.2	17.20	2,635.3	0.15%	2.49%	21.50%	0.00%	0.03%
Extendicare Inc/US	EXE	86.2	7.99	688.3	0.04%	10.51%	n/a	0.00%	n/a
Fairfax Financial Holdings Ltd	FFH	19.9	390.85	7,764.5	0.45%	2.63%	n/a	0.01%	n/a
Finning International Inc	FTT	171.9	25.90	4,452.7	0.26%	2.22%	10.00%	0.01%	0.03%
First Capital Realty Inc	FCR	206.5	18.96	3,914.4	0.23%	4.43%	n/a	0.01%	n/a
First Majestic Silver Corp	FR	116.8	16.24	1,896.1	0.11%	n/a	17.07%	n/a	0.02%
First Quantum Minerals Ltd	FM	476.3	18.97	9,035.6	0.53%	1.02%	10.39%	0.01%	0.05%
FirstService Corp/Canada	FSV	28.8	33.57	965.6	0.06%	n/a	13.00%	n/a	0.01%
Fortis Inc/Canada	FTS	191.7	33.68	6,455.8	0.38%	3.69%	n/a	0.01%	n/a
Fortuna Silver Mines Inc	FVI	125.3	3.94	493.6	0.03%	n/a	28.00%	n/a	0.01%
Franco-Nevada Corp	FNV	146.5	48.31	7,079.8	0.41%	1.15%	4.00%	0.00%	0.02%
Freehold Royalties Ltd	FRU	66.3	21.49	1,425.6	0.08%	7.82%	n/a	0.01%	n/a
Gabriel Resources Ltd	GBU	380.5	2.50	951.3	0.06%	n/a	n/a	n/a	n/a
Genivar Inc	GNV	51.4	23.44	1,205.2	0.07%	6.40%	n/a	0.00%	n/a
Genworth MI Canada Inc	MIC	98.7	25.25	2,491.6	0.14%	5.13%	n/a	0.01%	n/a
George Weston Ltd	WN	127.6	73.85	9,426.5	0.55%	2.06%	10.00%	0.01%	0.05%

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Gibson Energy Inc	GEI	120.6	25.08	3,024.7	0.18%	4.05%	n/a	0.01%	n/a
Gildan Activewear Inc	GIL	121.6	38.05	4,628.5	0.27%	0.98%	12.50%	0.00%	0.03%
Goldcorp Inc	G	811.5	33.44	27,137.2	1.58%	1.78%	45.50%	0.03%	0.72%
Granite Real Estate Investment Trust	GRT-U	46.9	39.92	1,871.6	0.11%	5.15%	n/a	0.01%	n/a
Great-West Lifeco Inc	GWO	950.9	27.28	25,940.5	1.51%	4.51%	10.00%	0.07%	0.15%
H&R Real Estate Investment Trust	HR-U	194.9	22.95	4,474.1	0.26%	5.14%	n/a	0.01%	n/a
Harry Winston Diamond Corp	HW	84.9	15.95	1,353.9	0.08%	0.00%	n/a	0.00%	n/a
Home Capital Group Inc	HCG	34.6	56.55	1,958.0	0.11%	1.92%	n/a	0.00%	n/a
HudBay Minerals Inc	HBM	172.0	9.64	1,658.2	0.10%	1.73%	43.00%	0.00%	0.04%
Husky Energy Inc	HSE	982.4	31.85	31,290.0	1.82%	3.77%	2.00%	0.07%	0.04%
IAMGOLD Corp	IMG	376.6	6.75	2,541.8	0.15%	3.75%	6.50%	0.01%	0.01%
IGM Financial Inc	IGM	252.0	45.34	11,424.3	0.66%	4.87%	n/a	0.03%	n/a
Imperial Oil Ltd	IMO	847.6	43.04	36,480.7	2.12%	1.15%	3.00%	0.02%	0.06%
Industrial Alliance Insurance & Financial Services Inc	IAG	97.4	37.04	3,607.8	0.21%	2.65%	11.00%	0.01%	0.02%
Inmet Mining Corp	IMN	69.4	66.55	4,616.3	0.27%	0.31%	-1.12%	0.00%	0.00%
Intact Financial Corp	IFC	133.3	65.97	8,796.0	0.51%	2.67%	n/a	0.01%	n/a
Inter Pipeline Fund	IPL-U	275.7	23.07	6,360.4	0.37%	4.82%	n/a	0.02%	n/a
Jean Coutu Group PJC Inc/The	PJC/A	100.7	15.75	1,585.7	0.09%	1.78%	n/a	0.00%	n/a
Just Energy Group Inc	JE	141.3	7.82	1,104.8	0.06%	15.86%	n/a	0.01%	n/a
Keyera Corp	KEY	77.8	54.39	4,233.1	0.25%	3.99%	n/a	0.01%	n/a
Kinross Gold Corp	K	1,140.3	7.86	8,962.7	0.52%	2.03%	28.00%	0.01%	0.15%
Kirkland Lake Gold Inc	KGI	70.2	6.08	426.5	0.02%	n/a	n/a	n/a	n/a
Labrador Iron Ore Royalty Corp	LIF	64.0	35.82	2,292.5	0.13%	3.92%	42.00%	0.01%	0.06%
Laurentian Bank of Canada	LB	28.1	45.18	1,271.3	0.07%	4.47%	5.00%	0.00%	0.00%
Legacy Oil + Gas Inc	LEG	143.3	6.19	887.3	0.05%	n/a	n/a	n/a	n/a
Linamar Corp	LNK	64.7	25.80	1,669.6	0.10%	1.24%	n/a	0.00%	n/a
Loblaw Cos Ltd	L	281.7	41.19	11,604.9	0.68%	2.14%	8.00%	0.01%	0.05%
Lundin Mining Corp	LUN	584.1	4.60	2,687.0	0.16%	n/a	15.81%	n/a	0.02%
MacDonald Dettwiler & Associates Ltd	MDA	31.9	71.00	2,262.3	0.13%	1.83%	6.00%	0.00%	0.01%
Magna International Inc	MG	233.3	56.81	13,256.2	0.77%	2.14%	12.11%	0.02%	0.09%
Major Drilling Group International	MDI	79.1	8.77	694.1	0.04%	2.17%	n/a	0.00%	n/a
Manitoba Telecom Services Inc	MBT	67.3	32.50	2,186.2	0.13%	5.23%	-6.00%	0.01%	-0.01%
Manulife Financial Corp	MFC	1,827.7	15.25	27,872.8	1.62%	3.44%	11.33%	0.06%	0.18%
Maple Leaf Foods Inc	MFI	140.0	13.45	1,883.6	0.11%	1.19%	n/a	0.00%	n/a
Martinrea International Inc	MRE	83.0	8.79	729.5	0.04%	n/a	n/a	n/a	n/a
MEG Energy Corp	MEG	220.7	33.04	7,290.8	0.42%	0.00%	40.00%	0.00%	0.17%
Methanex Corp	MX	94.4	38.39	3,622.8	0.21%	1.98%	25.00%	0.00%	0.05%
Metro Inc	MRU	96.3	64.90	6,249.0	0.36%	1.53%	8.00%	0.01%	0.03%
Mullen Group Ltd	MTL	87.9	21.97	1,930.2	0.11%	5.01%	n/a	0.01%	n/a
National Bank of Canada	NA	162.2	77.99	12,650.5	0.74%	4.37%	8.50%	0.03%	0.06%
Nevsun Resources Ltd	NSU	199.0	3.80	756.2	0.04%	2.71%	19.00%	0.00%	0.01%
New Gold Inc	NGD	476.1	9.49	4,517.9	0.26%	0.00%	24.50%	0.00%	0.06%
Niko Resources Ltd	NKO	70.2	6.75	474.0	0.03%	0.73%	n/a	0.00%	n/a
Nordion Inc	NDN	61.9	7.08	438.3	0.03%	n/a	n/a	n/a	n/a
North West Co Inc/The	NWC	48.4	22.96	1,110.8	0.06%	4.53%	n/a	0.00%	n/a
Northern Property Real Estate Investment Trust	NPR-U	31.9	31.74	1,014.1	0.06%	4.82%	n/a	0.00%	n/a
Northland Power Inc	NPI	86.2	18.85	1,624.9	0.09%	5.73%	n/a	0.01%	n/a
Novagold Resources Inc	NG	316.6	4.03	1,276.0	0.07%	n/a	n/a	n/a	n/a
OceanaGold Corp	OGC	293.5	2.43	713.2	0.04%	n/a	n/a	n/a	n/a
Onex Corp	OCX	114.0	46.72	5,323.9	0.31%	n/a	n/a	n/a	n/a
Open Text Corp	OTC	58.6	56.42	3,305.9	0.19%	n/a	10.00%	n/a	0.02%
Osisko Mining Corp	OSK	436.5	5.90	2,575.5	0.15%	0.25%	n/a	0.00%	n/a
Pacific Rubiales Energy Corp	PRE	322.4	25.11	8,094.5	0.47%	1.79%	30.26%	0.01%	0.14%
Pan American Silver Corp	PAA	151.8	16.68	2,532.3	0.15%	2.45%	0.00%	0.00%	0.00%
Paramount Resources Ltd	POU	90.1	37.76	3,400.3	0.20%	n/a	n/a	n/a	n/a
Parkland Fuel Corp	PKI	68.4	17.43	1,192.1	0.07%	5.97%	n/a	0.00%	n/a
Pason Systems Inc	PSI	82.0	15.99	1,312.0	0.08%	2.38%	2.60%	0.00%	0.00%
Pembina Pipeline Corp	PPL	294.1	28.99	8,525.5	0.50%	5.55%	n/a	0.03%	n/a
Pengrowth Energy Corp	PGF	512.6	4.60	2,357.8	0.14%	10.43%	n/a	0.01%	n/a
Penn West Petroleum Ltd	PWT	482.1	10.01	4,826.2	0.28%	10.28%	n/a	0.03%	n/a
PetroBakken Energy Ltd	PBN	191.6	8.46	1,620.5	0.09%	11.35%	n/a	0.01%	n/a
Petrobank Energy & Resources Ltd	PBG	97.6	0.77	75.1	0.00%	0.00%	n/a	0.00%	n/a

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Petrominerales Ltd	PMG	84.5	8.47	715.8	0.04%	6.09%	n/a	0.00%	n/a
Peyto Exploration & Development Corp	PEY	148.7	24.86	3,696.0	0.22%	2.90%	n/a	0.01%	n/a
Potash Corp of Saskatchewan Inc	POT	865.0	40.66	35,170.7	2.05%	2.74%	7.18%	0.06%	0.15%
Power Corp of Canada	POW	411.1	27.44	11,281.8	0.66%	4.23%	n/a	0.03%	n/a
Power Financial Corp	POWF	709.1	29.68	21,046.2	1.22%	4.72%	n/a	0.06%	n/a
Precision Drilling Corp	PD	276.5	8.41	2,325.2	0.14%	2.00%	30.45%	0.00%	0.04%
Premier Gold Mines Ltd	PG	149.0	2.78	414.3	0.02%	n/a	n/a	n/a	n/a
Pretium Resources Inc	PVG	96.5	7.75	747.7	0.04%	0.00%	n/a	0.00%	n/a
Primaris Retail Real Estate Investment Trust	PMZ-U	98.4	27.23	2,680.0	0.16%	4.48%	n/a	0.01%	n/a
Progressive Waste Solutions Ltd	BIN	115.2	21.28	2,450.7	0.14%	2.72%	1.20%	0.00%	0.00%
Quebecor Inc	QBR/B	42.7	44.70	1,910.8	0.11%	0.45%	4.31%	0.00%	0.00%
Reitmans Canada Ltd	RET/A	51.1	10.76	550.3	0.03%	7.43%	n/a	0.00%	n/a
Research In Motion Ltd	BB	524.2	13.62	7,139.1	0.42%	0.00%	20.00%	0.00%	0.08%
Rio Alto Mining Ltd	RIO	175.9	4.75	835.5	0.05%	0.00%	n/a	0.00%	n/a
RioCan Real Estate Investment Trust	REI-U	298.1	27.59	8,225.2	0.48%	5.11%	n/a	0.02%	n/a
Rogers Communications Inc	RCI/B	402.8	48.98	19,728.6	1.15%	3.53%	7.91%	0.04%	0.09%
RONA Inc	RON	121.4	11.46	1,391.3	0.08%	1.22%	n/a	0.00%	n/a
Royal Bank of Canada	RY	1,446.3	63.90	92,415.8	5.38%	3.92%	6.77%	0.21%	0.36%
Rubicon Minerals Corp	RMX	288.3	2.20	634.2	0.04%	n/a	n/a	n/a	n/a
Russel Metals Inc	RUS	60.2	28.52	1,717.0	0.10%	4.91%	n/a	0.00%	n/a
Saputo Inc	SAP	197.2	50.61	9,982.0	0.58%	1.63%	10.00%	0.01%	0.06%
Savanna Energy Services Corp	SVY	86.0	7.15	614.8	0.04%	3.90%	63.20%	0.00%	0.02%
Secure Energy Services Inc	SES	104.7	10.44	1,093.3	0.06%	0.00%	n/a	0.00%	n/a
SEMAFO Inc	SMF	273.2	2.76	754.1	0.04%	0.97%	n/a	0.00%	n/a
Shaw Communications Inc	SJR/B	424.6	24.45	10,382.6	0.60%	4.07%	9.24%	0.02%	0.06%
ShawCor Ltd	SCL/A	57.5	40.25	2,314.7	0.13%	0.99%	19.20%	0.00%	0.03%
Sherritt International Corp	S	296.9	5.20	1,544.1	0.09%	3.08%	30.00%	0.00%	0.03%
Shoppers Drug Mart Corp	SC	204.1	42.85	8,744.0	0.51%	2.63%	5.00%	0.01%	0.03%
Silver Standard Resources Inc	SSO	80.7	10.27	829.3	0.05%	0.00%	18.00%	0.00%	0.01%
Silver Wheaton Corp	SLW	354.4	32.62	11,559.7	0.67%	1.18%	29.77%	0.01%	0.20%
Silvercorp Metals Inc	SVM	170.8	3.72	635.2	0.04%	n/a	n/a	n/a	n/a
SNC-Lavalin Group Inc	SNC	151.1	46.00	6,951.9	0.40%	1.89%	8.00%	0.01%	0.03%
Stantec Inc	STN	46.0	42.84	1,972.1	0.11%	1.54%	10.15%	0.00%	0.01%
Sun Life Financial Inc	SLF	599.8	28.34	16,998.8	0.99%	5.08%	8.00%	0.05%	0.08%
Suncor Energy Inc	SU	1,522.6	30.93	47,093.4	2.74%	1.94%	-6.00%	0.05%	-0.16%
Superior Plus Corp	SPB	112.9	11.49	1,297.0	0.08%	5.22%	n/a	0.00%	n/a
Tahoe Resources Inc	THO	145.6	15.49	2,254.8	0.13%	n/a	n/a	n/a	n/a
Talisman Energy Inc	TLM	1,032.7	12.67	13,084.9	0.76%	2.19%	-3.00%	0.02%	-0.02%
Taseko Mines Ltd	TKO	191.1	2.86	546.5	0.03%	n/a	36.00%	n/a	0.01%
Teck Resources Ltd	TCK/B	572.9	31.07	17,800.5	1.04%	2.86%	7.46%	0.03%	0.08%
TELUS Corp	T	326.0	70.76	23,070.5	1.34%	3.75%	7.85%	0.05%	0.11%
Thompson Creek Metals Co Inc	TCM	169.0	3.34	564.3	0.03%	0.00%	61.50%	0.00%	0.02%
Thomson Reuters Corp	TRI	827.3	31.30	25,893.9	1.51%	4.31%	5.95%	0.06%	0.09%
Tim Hortons Inc	THI	153.4	50.23	7,705.5	0.45%	2.01%	12.00%	0.01%	0.05%
TMX Group Ltd	X	53.8	55.07	2,960.9	0.17%	2.91%	n/a	0.01%	n/a
Torex Gold Resources Inc	TXG	604.5	1.75	1,057.8	0.06%	n/a	n/a	n/a	n/a
Toromont Industries Ltd	TIH	76.4	23.69	1,811.0	0.11%	2.14%	n/a	0.00%	n/a
Toronto-Dominion Bank/The	TD	922.4	85.05	78,447.1	4.56%	3.83%	8.27%	0.17%	0.38%
Tourmaline Oil Corp	TOU	175.4	36.63	6,426.0	0.37%	0.00%	n/a	0.00%	n/a
TransAlta Corp	TA	258.4	15.42	3,984.8	0.23%	7.52%	n/a	0.02%	n/a
TransCanada Corp	TRP	705.9	47.81	33,746.9	1.96%	3.85%	n/a	0.08%	n/a
Transcontinental Inc	TCL/A	63.0	12.76	804.5	0.05%	4.98%	2.00%	0.00%	0.00%
TransForce Inc	TFI	92.9	20.86	1,937.3	0.11%	2.68%	n/a	0.00%	n/a
TransGlobe Energy Corp	TGL	73.8	8.23	607.3	0.04%	n/a	n/a	n/a	n/a
Trican Well Service Ltd	TCW	148.8	13.64	2,030.1	0.12%	2.20%	30.50%	0.00%	0.04%
Trilogy Energy Corp	TET	91.1	27.21	2,479.4	0.14%	1.54%	n/a	0.00%	n/a
Trinidad Drilling Ltd	TDG	120.9	6.99	844.8	0.05%	2.86%	n/a	0.00%	n/a
Turquoise Hill Resources Ltd	TRQ	1,005.6	7.19	7,230.2	0.42%	0.00%	n/a	0.00%	n/a
Uranium One Inc	UUU	957.2	2.73	2,613.1	0.15%	0.00%	53.00%	0.00%	0.08%
Valeant Pharmaceuticals International Inc	VRX	298.1	69.77	20,795.8	1.21%	n/a	14.67%	n/a	0.18%
Veresen Inc	VSN	198.1	12.96	2,567.5	0.15%	7.72%	n/a	0.01%	n/a
Vermilion Energy Inc	VET	99.2	53.30	5,289.4	0.31%	4.28%	n/a	0.01%	n/a

Foward-Looking Market Risk Premium -- Canada

Wajax Corp	WJX	16.7	42.85	717.2	0.04%	7.29%	n/a	0.00%	n/a
West Fraser Timber Co Ltd	WFT	40.3	84.94	3,421.5	0.20%	0.66%	n/a	0.00%	n/a
Westjet Airlines Ltd	WJA	124.1	22.52	2,793.8	0.16%	1.78%	18.51%	0.00%	0.03%
Westport Innovations Inc	WPT	55.3	29.10	1,609.1	0.09%	0.00%	30.00%	0.00%	0.03%
Westshore Terminals Investment Corp	WTE	74.3	27.39	2,033.7	0.12%	4.29%	n/a	0.01%	n/a
Whitecap Resources Inc	WCP	129.3	8.87	1,146.8	0.07%	0.00%	n/a	0.00%	n/a
Wi-Lan Inc	WIN	121.5	4.42	537.2	0.03%	n/a	n/a	n/a	n/a
Yamana Gold Inc	YRI	752.3	15.21	11,442.7	0.67%	1.65%	27.70%	0.01%	0.18%

Notes:

-
- [1] Equals sum of column [14]
 [2] Equals sum of column [15]
 [3] Equals [1] x (1 + 0.5 x [2]) + [2]
 [4] Source: Equals average long-term Consensus Forecast of 10-year Canadian government bond yield for the period 2013-2022
 [5] Equals 30-day average spread between 10- and 30-year Canadian government bond ending February 28, 2013.
 [6] Equals [5] + [6]
 [7] Equals [3]+[6]
 [8] Source: Bloomberg
 [9] Source: Bloomberg
 [10] Equals [8] x [9]
 [11] Equals [10] / sum of column [10]
 [12] Source: Bloomberg
 [13] Source: Bloomberg
 [14] Equals [11] x [12]
 [15] Equals [11] x [13]

30-DAY CONSTANT GROWTH DCF -- U.S. PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Consolidated Edison	ED	\$2.46	\$59.63	4.13%	4.19%	2.97%	3.20%	3.50%	2.00%	2.92%	6.17%	7.10%	7.70%
NextEra Energy, Inc.	NEE	\$2.64	\$72.18	3.66%	3.77%	5.95%	6.60%	5.50%	6.37%	6.11%	9.26%	9.87%	10.38%
Northeast Utilities	NU	\$1.47	\$40.68	3.61%	3.74%	7.05%	8.00%	6.50%	6.58%	7.03%	10.23%	10.77%	11.76%
Southern Co.	SO	\$1.96	\$44.15	4.44%	4.55%	4.98%	5.00%	4.50%	4.83%	4.83%	9.04%	9.37%	9.55%
Wisconsin Energy	WEC	\$1.36	\$39.53	3.44%	3.54%	5.53%	4.80%	6.50%	5.37%	5.55%	8.32%	9.09%	10.05%
Xcel Energy, Inc.	XEL	\$1.08	\$27.80	3.88%	3.98%	4.73%	5.00%	6.00%	4.95%	5.17%	8.71%	9.15%	10.00%
MEAN		\$1.83	\$47.33	3.86%	3.96%	5.20%	5.43%	5.42%	5.02%	5.27%	8.62%	9.23%	9.91%
MEDIAN		\$1.72	\$42.41	3.77%	3.88%	5.26%	5.00%	5.75%	5.16%	5.36%	8.87%	9.26%	10.03%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, 30-day average as of February 28, 2013

[3] Equals [1] / [2]

[4] Equals [3] x (1 + 0.5 x [9])

[5] Source: Zacks at February 28, 2013

[6] Source: SNL Financial at February 28, 2013

[7] Source: Value Line

[8] Source: Yahoo! Finance at February 28, 2013

[9] Equals Average([5], [6], [7], [8])

[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])

[11] Equals [4] + [9]

[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

90-DAY CONSTANT GROWTH DCF -- U.S. PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Consolidated Edison	ED	\$2.46	\$56.68	4.34%	4.40%	2.97%	3.20%	3.50%	2.00%	2.92%	6.38%	7.32%	7.92%
NextEra Energy, Inc.	NEE	\$2.64	\$70.32	3.75%	3.87%	5.95%	6.60%	5.50%	6.37%	6.11%	9.36%	9.97%	10.48%
Northeast Utilities	NU	\$1.47	\$39.50	3.72%	3.85%	7.05%	8.00%	6.50%	6.58%	7.03%	10.34%	10.89%	11.87%
Southern Co.	SO	\$1.96	\$43.88	4.47%	4.57%	4.98%	5.00%	4.50%	4.83%	4.83%	9.07%	9.40%	9.58%
Wisconsin Energy	WEC	\$1.36	\$38.09	3.57%	3.67%	5.53%	4.80%	6.50%	5.37%	5.55%	8.46%	9.22%	10.19%
Xcel Energy, Inc.	XEL	\$1.08	\$27.32	3.95%	4.05%	4.73%	5.00%	6.00%	4.95%	5.17%	8.78%	9.22%	10.07%
MEAN		\$1.83	\$45.97	3.97%	4.07%	5.20%	5.43%	5.42%	5.02%	5.27%	8.73%	9.34%	10.02%
MEDIAN		\$1.72	\$41.69	3.85%	3.96%	5.26%	5.00%	5.75%	5.16%	5.36%	8.92%	9.31%	10.13%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, 90-day average as of February 28, 2013

[3] Equals [1] / [2]

[4] Equals [3] x (1 + 0.5 x [9])

[5] Source: Zacks at February 28, 2013

[6] Source: SNL Financial at February 28, 2013

[7] Source: Value Line

[8] Source: Yahoo! Finance at February 28, 2013

[9] Equals Average([5], [6], [7], [8])

[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])

[11] Equals [4] + [9]

[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

180-DAY CONSTANT GROWTH DCF -- U.S. PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Consolidated Edison	ED	\$2.46	\$59.63	4.13%	4.19%	2.97%	3.20%	3.50%	2.00%	2.92%	6.17%	7.10%	7.70%
NextEra Energy, Inc.	NEE	\$2.64	\$69.60	3.79%	3.91%	5.95%	6.60%	5.50%	6.37%	6.11%	9.40%	10.01%	10.52%
Northeast Utilities	NU	\$1.47	\$39.06	3.76%	3.90%	7.05%	8.00%	6.50%	6.58%	7.03%	10.39%	10.93%	11.91%
Southern Co.	SO	\$1.96	\$45.18	4.34%	4.44%	4.98%	5.00%	4.50%	4.83%	4.83%	8.94%	9.27%	9.45%
Wisconsin Energy	WEC	\$1.36	\$38.50	3.53%	3.63%	5.53%	4.80%	6.50%	5.37%	5.55%	8.42%	9.18%	10.15%
Xcel Energy, Inc.	XEL	\$1.08	\$27.83	3.88%	3.98%	4.73%	5.00%	6.00%	4.95%	5.17%	8.70%	9.15%	10.00%
MEAN		\$1.83	\$46.63	3.91%	4.01%	5.20%	5.43%	5.42%	5.02%	5.27%	8.67%	9.27%	9.95%
MEDIAN		\$1.72	\$42.12	3.84%	3.95%	5.26%	5.00%	5.75%	5.16%	5.36%	8.82%	9.23%	10.07%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, 180-day average as of February 28, 2013

[3] Equals [1] / [2]

[4] Equals [3] x (1 + 0.5 x [9])

[5] Source: Zacks at February 28, 2013

[6] Source: SNL Financial at February 28, 2013

[7] Source: Value Line

[8] Source: Yahoo! Finance at February 28, 2013

[9] Equals Average([5], [6], [7], [8])

[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])

[11] Equals [4] + [9]

[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

30-DAY CONSTANT GROWTH DCF -- CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Canadian Utilities Limited	CU	\$1.94	\$74.76	2.60%	2.70%	--	7.70%	--	7.80%	7.75%	10.39%	10.45%	10.50%
Emera Inc.	EMA	\$1.40	\$35.60	3.93%	4.08%	--	7.50%	--	7.45%	7.48%	11.53%	11.55%	11.58%
Enbridge Inc.	ENB	\$1.26	\$44.49	2.83%	2.98%	9.85%	10.00%	10.00%	12.60%	10.61%	12.82%	13.60%	15.61%
Fortis Inc.	FTS	\$1.24	\$34.00	3.65%	3.73%	--	4.90%	--	3.97%	4.44%	7.69%	8.16%	8.64%
TransCanada Corporation	TRP	\$1.76	\$48.09	3.66%	3.82%	--	--	11.50%	6.47%	8.99%	10.25%	12.81%	15.37%
Valener Inc.	VNR	\$1.00	\$16.15	6.19%	6.41%	--	6.00%	--	8.00%	7.00%	12.38%	13.41%	14.44%
MEAN		\$1.43	\$42.18	3.81%	3.95%	--	7.22%	10.75%	7.72%	7.71%	10.84%	11.66%	12.69%
MEDIAN		\$1.33	\$40.04	3.65%	3.78%	--	7.50%	10.75%	7.63%	7.61%	10.96%	12.18%	13.01%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, 30-day average as of February 28, 2013

[3] Equals [1] / [2]

[4] Equals [3] x (1 + 0.5 x [9])

[5] Source: Zacks at February 28, 2013

[6] Source: SNL Financial at February 28, 2013

[7] Source: Value Line

[8] Source: Yahoo! Finance at February 28, 2013

[9] Equals Average([5], [6], [7], [8])

[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])

[11] Equals [4] + [9]

[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

90-DAY CONSTANT GROWTH DCF -- CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Canadian Utilities Limited	CU	\$1.94	\$70.53	2.75%	2.86%	--	7.70%	--	7.80%	7.75%	10.56%	10.61%	10.66%
Emera Inc.	EMA	\$1.40	\$34.92	4.01%	4.16%	--	7.50%	--	7.45%	7.48%	11.61%	11.63%	11.66%
Enbridge Inc.	ENB	\$1.26	\$42.07	3.00%	3.15%	9.85%	10.00%	10.00%	12.60%	10.61%	12.99%	13.77%	15.78%
Fortis Inc.	FTS	\$1.24	\$33.80	3.67%	3.75%	--	4.90%	--	3.97%	4.44%	7.71%	8.19%	8.66%
TransCanada Corporation	TRP	\$1.76	\$46.59	3.78%	3.95%	--	--	11.50%	6.47%	8.99%	10.37%	12.93%	15.50%
Valener Inc.	VNR	\$1.00	\$16.06	6.23%	6.45%	--	6.00%	--	8.00%	7.00%	12.41%	13.45%	14.48%
MEAN		\$1.43	\$40.66	3.91%	4.05%	--	7.22%	10.75%	7.72%	7.71%	10.94%	11.76%	12.79%
MEDIAN		\$1.33	\$38.49	3.72%	3.85%	--	7.50%	10.75%	7.63%	7.61%	11.08%	12.28%	13.07%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, 90-day average as of February 28, 2013

[3] Equals [1] / [2]

[4] Equals [3] x (1 + 0.5 x [9])

[5] Source: Zacks at February 28, 2013

[6] Source: SNL Financial at February 28, 2013

[7] Source: Value Line

[8] Source: Yahoo! Finance at February 28, 2013

[9] Equals Average([5], [6], [7], [8])

[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])

[11] Equals [4] + [9]

[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

180-DAY CONSTANT GROWTH DCF -- CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Canadian Utilities Limited	CU	\$1.94	\$69.35	2.80%	2.91%	--	7.70%	--	7.80%	7.75%	10.61%	10.66%	10.71%
Emera Inc.	EMA	\$1.40	\$34.69	4.04%	4.19%	--	7.50%	--	7.45%	7.48%	11.64%	11.66%	11.69%
Enbridge Inc.	ENB	\$1.26	\$40.87	3.08%	3.25%	9.85%	10.00%	10.00%	12.60%	10.61%	13.08%	13.86%	15.88%
Fortis Inc.	FTS	\$1.24	\$33.46	3.71%	3.79%	--	4.90%	--	3.97%	4.44%	7.75%	8.22%	8.70%
TransCanada Corporation	TRP	\$1.76	\$45.46	3.87%	4.05%	--	--	11.50%	6.47%	8.99%	10.47%	13.03%	15.59%
Valener Inc.	VNR	\$1.00	\$15.91	6.28%	6.50%	--	6.00%	--	8.00%	7.00%	12.47%	13.50%	14.54%
MEAN		\$1.43	\$39.96	3.96%	4.11%	--	7.22%	10.75%	7.72%	7.71%	11.00%	11.82%	12.85%
MEDIAN		\$1.33	\$37.78	3.79%	3.92%	--	7.50%	10.75%	7.63%	7.61%	11.12%	12.35%	13.11%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, 180-day average as of February 28, 2013

[3] Equals [1] / [2]

[4] Equals [3] x (1 + 0.5 x [9])

[5] Source: Zacks at February 28, 2013

[6] Source: SNL Financial at February 28, 2013

[7] Source: Value Line

[8] Source: Yahoo! Finance at February 28, 2013

[9] Equals Average([5], [6], [7], [8])

[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])

[11] Equals [4] + [9]

[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

30-DAY SUSTAINABLE GROWTH DCF -- U.S. PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call	Sustainable Growth Estimate	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Consolidated Edison	ED	\$2.46	\$59.63	4.13%	4.19%	2.97%	3.20%	3.50%	2.00%	3.36%	3.14%	6.17%	7.33%	7.70%
NextEra Energy, Inc.	NEE	\$2.64	\$72.18	3.66%	3.77%	5.95%	6.60%	5.50%	6.37%	6.25%	6.18%	9.26%	9.95%	10.38%
Northeast Utilities	NU	\$1.47	\$40.68	3.61%	3.71%	7.05%	8.00%	6.50%	6.58%	3.74%	5.39%	7.42%	9.10%	11.76%
Southern Co.	SO	\$1.96	\$44.15	4.44%	4.54%	4.98%	5.00%	4.50%	4.83%	4.02%	4.42%	8.55%	8.96%	9.55%
Wisconsin Energy	WEC	\$1.36	\$39.53	3.44%	3.54%	5.53%	4.80%	6.50%	5.37%	5.62%	5.59%	8.32%	9.12%	10.05%
Xcel Energy, Inc.	XEL	\$1.08	\$27.80	3.88%	3.98%	4.73%	5.00%	6.00%	4.95%	4.18%	4.67%	8.14%	8.65%	10.00%
MEAN		\$1.83	\$47.33	3.86%	3.95%	5.20%	5.43%	5.42%	5.02%	4.53%	4.90%	7.98%	8.85%	9.91%
MEDIAN		\$1.72	\$42.41	3.77%	3.87%	5.26%	5.00%	5.75%	5.16%	4.10%	5.03%	8.23%	9.03%	10.03%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, 30-day average as of February 28, 2013

[3] Equals [1] / [2]

[4] Equals [3] x (1+(0.5 x [10]))

[5] Source: Zacks at February 28, 2013

[6] Source: SNL Financial at February 28, 2013

[7] Source: Value Line

[8] Source: Yahoo! Finance at February 28, 2013

[9] Source: Sustainable Growth Calculation

[10] Equals 0.5 x Average ([5], [6], [7], [8]) + 0.5 x [9]

[11] Equals [3] x (1 + (0.5 x Minimum ([5], [6], [7], [8], [9]))) + Minimum ([5], [6], [7], [8], [9])

[12] Equals [4] + [10]

[13] Equals [3] x (1 + (0.5 x Maximum ([5], [6], [7], [8], [9]))) + Maximum ([5], [6], [7], [8], [9])

90-DAY SUSTAINABLE GROWTH DCF -- U.S. PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
Company		Annualized	Stock Price	Dividend	Expected	Zacks EPS	SNL EPS	Value Line	First Call	Sustainable	Average	Low DCF	Mean DCF	High DCF
		Dividend		Yield	Dividend	Growth	Growth	EPS		Growth	Growth			
Consolidated Edison	ED	\$2.46	\$56.68	4.34%	4.41%	2.97%	3.20%	3.50%	2.00%	3.36%	3.14%	6.38%	7.55%	7.92%
NextEra Energy, Inc.	NEE	\$2.64	\$70.32	3.75%	3.87%	5.95%	6.60%	5.50%	6.37%	6.25%	6.18%	9.36%	10.05%	10.48%
Northeast Utilities	NU	\$1.47	\$39.50	3.72%	3.82%	7.05%	8.00%	6.50%	6.58%	3.74%	5.39%	7.53%	9.21%	11.87%
Southern Co.	SO	\$1.96	\$43.88	4.47%	4.57%	4.98%	5.00%	4.50%	4.83%	4.02%	4.42%	8.58%	8.99%	9.58%
Wisconsin Energy	WEC	\$1.36	\$38.09	3.57%	3.67%	5.53%	4.80%	6.50%	5.37%	5.62%	5.59%	8.46%	9.26%	10.19%
Xcel Energy, Inc.	XEL	\$1.08	\$27.32	3.95%	4.04%	4.73%	5.00%	6.00%	4.95%	4.18%	4.67%	8.21%	8.72%	10.07%
MEAN		\$1.83	\$45.97	3.97%	4.06%	5.20%	5.43%	5.42%	5.02%	4.53%	4.90%	8.09%	8.96%	10.02%
MEDIAN		\$1.72	\$41.69	3.85%	3.96%	5.26%	5.00%	5.75%	5.16%	4.10%	5.03%	8.34%	9.10%	10.13%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, 90-day average as of February 28, 2013

[3] Equals [1] / [2]

[4] Equals [3] x (1+(0.5 x [10]))

[5] Source: Zacks at February 28, 2013

[6] Source: SNL Financial at February 28, 2013

[7] Source: Value Line

[8] Source: Yahoo! Finance at February 28, 2013

[9] Source: Sustainable Growth Calculation

[10] Equals 0.5 x Average ([5], [6], [7], [8]) + 0.5 x [9]

[11] Equals [3] x (1 + (0.5 x Minimum ([5], [6], [7], [8], [9]))) + Minimum ([5], [6], [7], [8], [9])

[12] Equals [4] + [10]

[13] Equals [3] x (1 + (0.5 x Maximum ([5], [6], [7], [8], [9]))) + Maximum ([5], [6], [7], [8], [9])

180-DAY SUSTAINABLE GROWTH DCF -- U.S. PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Expected				Value Line		Sustainable		Average				
		Annualized		Dividend	Dividend	Zacks EPS	SNL EPS	EPS		Growth	Growth	Low DCF	Mean DCF	High DCF
Company		Dividend	Stock Price	Yield	Yield	Growth	Growth	Growth	First Call	Estimate	Rate	ROE	ROE	ROE
Consolidated Edison	ED	\$2.46	\$59.63	4.13%	4.19%	2.97%	3.20%	3.50%	2.00%	3.36%	3.14%	6.17%	7.33%	7.70%
NextEra Energy, Inc.	NEE	\$2.64	\$69.60	3.79%	3.91%	5.95%	6.60%	5.50%	6.37%	6.25%	6.18%	9.40%	10.09%	10.52%
Northeast Utilities	NU	\$1.47	\$39.06	3.76%	3.86%	7.05%	8.00%	6.50%	6.58%	3.74%	5.39%	7.57%	9.25%	11.91%
Southern Co.	SO	\$1.96	\$45.18	4.34%	4.43%	4.98%	5.00%	4.50%	4.83%	4.02%	4.42%	8.45%	8.86%	9.45%
Wisconsin Energy	WEC	\$1.36	\$38.50	3.53%	3.63%	5.53%	4.80%	6.50%	5.37%	5.62%	5.59%	8.42%	9.22%	10.15%
Xcel Energy, Inc.	XEL	\$1.08	\$27.83	3.88%	3.97%	4.73%	5.00%	6.00%	4.95%	4.18%	4.67%	8.14%	8.65%	10.00%
MEAN		\$1.83	\$46.63	3.91%	4.00%	5.20%	5.43%	5.42%	5.02%	4.53%	4.90%	8.02%	8.90%	9.95%
MEDIAN		\$1.72	\$42.12	3.84%	3.94%	5.26%	5.00%	5.75%	5.16%	4.10%	5.03%	8.28%	9.04%	10.07%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, 180-day average as of February 28, 2013

[3] Equals [1] / [2]

[4] Equals [3] x (1+(0.5 x [10]))

[5] Source: Zacks at February 28, 2013

[6] Source: SNL Financial at February 28, 2013

[7] Source: Value Line

[8] Source: Yahoo! Finance at February 28, 2013

[9] Source: Sustainable Growth Calculation

[10] Equals 0.5 x Average ([5], [6], [7], [8]) + 0.5 x [9]

[11] Equals [3] x (1 + (0.5 x Minimum ([5], [6], [7], [8], [9]))) + Minimum ([5], [6], [7], [8], [9])

[12] Equals [4] + [10]

[13] Equals [3] x (1 + (0.5 x Maximum ([5], [6], [7], [8], [9]))) + Maximum ([5], [6], [7], [8], [9])

SUSTAINABLE GROWTH RATE CALCULATION -- U.S. PROXY GROUP

Company	Ticker	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]
		Payout Ratio			Average Retention Ratio	Return on Common Equity			Average Return on Common Equity	B*R	Common Shares Outstanding			Price (2015-17)		0.75%	Book Value per Share 2015-17	Market/ Book Ratio	"S"	"V"	S*V	BR + SV
		2012	2013	2015-17		2012	2013	2015-17			2011	2015-17	Growth	High	Low	Mid						
Consolidated Edison	ED	65.00%	63.00%	60.00%	37.33%	9.00%	9.00%	9.00%	9.00%	3.36%	293.00	293.00	0.00%	65.00	50.00	57.5	47.75	1.20	0.00%	16.96%	0.00%	3.36%
NextEra Energy, Inc.	NEE	53.00%	54.00%	55.00%	46.00%	12.50%	12.50%	12.50%	12.50%	5.75%	422.00	438.00	0.75%	100.00	75.00	87.5	52.25	1.67	1.25%	40.29%	0.50%	6.25%
Northeast Utilities	NU	59.00%	58.00%	56.00%	42.33%	8.50%	8.50%	9.50%	8.83%	3.74%	314.00	314.00	0.00%	50.00	40.00	45	35.25	1.28	0.00%	21.67%	0.00%	3.74%
Southern Co.	SO	73.00%	73.00%	73.00%	27.00%	13.00%	13.00%	12.50%	12.83%	3.47%	872.00	905.00	0.75%	50.00	40.00	45	25.75	1.75	1.30%	42.78%	0.56%	4.02%
Wisconsin Energy	WEC	51.00%	56.00%	64.00%	43.00%	13.00%	13.00%	13.50%	13.17%	5.66%	230.49	230.00	-0.04%	45.00	35.00	40	20.50	1.95	-0.08%	48.75%	-0.04%	5.62%
Xcel Energy, Inc.	XEL	58.00%	58.00%	60.00%	41.33%	10.00%	9.50%	10.00%	9.83%	4.06%	507.00	515.00	0.31%	35.00	25.00	30	22.00	1.36	0.43%	26.67%	0.11%	4.18%
MEAN																						4.53%
MEDIAN																						4.10%

Notes:

- [1] Source: Value Line; "All Div'ds to Net Prof"
[2] Source: Value Line; "All Div'ds to Net Prof"
[3] Source: Value Line; "All Div'ds to Net Prof"
[4] Equals 1 - Average ([1]:[3])
[5] Source: Value Line; "Return on Com Eq"
[6] Source: Value Line; "Return on Com Eq"
[7] Source: Value Line; "Return on Com Eq"
[8] Equals Average ([5]:[7])
[9] Equals [4] x [6]
[10] Source: Value Line; "Common Shs Outst'g"
[11] Source: Value Line; "Common Shs Outst'g"
[12] Equals ([10] / [11]) ^ 0.2 - 1
[13] Source: Value Line
[14] Source: Value Line
[15] Average ([13], [14])
[16] Source: Value Line; "Book Value per sh"
[17] Equals [15] / [16]
[18] Equals [12] x [17]
[19] Equals 1 - (1 / [17])
[20] Equals [18] x [19]
[21] Equals [9] + [20]

30-DAY MULTI-STAGE DCF -- U.S. PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Consolidated Edison	ED	\$2.46	\$59.63	2.92%	3.26%	3.60%	3.94%	4.28%	4.62%	4.96%	8.76%
NextEra Energy, Inc.	NEE	\$2.64	\$72.18	6.11%	5.91%	5.72%	5.53%	5.34%	5.15%	4.96%	2.06%
Northeast Utilities	NU	\$1.47	\$40.68	7.03%	6.69%	6.34%	6.00%	5.65%	5.31%	4.96%	9.27%
Southern Co.	SO	\$1.96	\$44.15	4.83%	4.85%	4.87%	4.89%	4.92%	4.94%	4.96%	9.58%
Wisconsin Energy	WEC	\$1.36	\$39.53	5.55%	5.45%	5.35%	5.25%	5.16%	5.06%	4.96%	8.71%
Xcel Energy, Inc.	XEL	\$1.08	\$27.80	5.17%	5.14%	5.10%	5.06%	5.03%	4.99%	4.96%	9.09%
MEAN		\$1.83	\$47.33	5.27%	5.22%	5.16%	5.11%	5.06%	5.01%	4.96%	7.91%
MEDIAN		\$1.72	\$42.41	5.36%	5.29%	5.23%	5.16%	5.09%	5.03%	4.96%	8.92%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, 30-day average as of January 18, 2013

[3] Source: Constant Growth DCF

[4] Equals $[3] - ([3] - [9]) / 6$

[5] Equals $[4] - ([3] - [9]) / 6$

[6] Equals $[5] - ([3] - [9]) / 6$

[7] Equals $[6] - ([3] - [9]) / 6$

[8] Equals $[7] - ([3] - [9]) / 6$

[9] Consensus Economics Inc., Consensus Forecasts, October 8, 2012

[10] Internal rate of return

90-DAY MULTI-STAGE DCF -- U.S. PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Annualized		Growth						GDP	
Company	Ticker	Dividend	Stock Price	Rate, Years	Year 6	Year 7	Year 8	Year 9	Year 10	Growth (perpetuity)	ROE
Consolidated Edison	ED	\$2.46	\$56.68	2.92%	3.26%	3.60%	3.94%	4.28%	4.62%	4.96%	8.96%
NextEra Energy, Inc.	NEE	\$2.64	\$70.32	6.11%	5.91%	5.72%	5.53%	5.34%	5.15%	4.96%	9.19%
Northeast Utilities	NU	\$1.47	\$39.50	7.03%	6.69%	6.34%	6.00%	5.65%	5.31%	4.96%	9.40%
Southern Co.	SO	\$1.96	\$43.88	4.83%	4.85%	4.87%	4.89%	4.92%	4.94%	4.96%	9.61%
Wisconsin Energy	WEC	\$1.36	\$38.09	5.55%	5.45%	5.35%	5.25%	5.16%	5.06%	4.96%	8.85%
Xcel Energy, Inc.	XEL	\$1.08	\$27.32	5.17%	5.14%	5.10%	5.06%	5.03%	4.99%	4.96%	9.16%
MEAN		\$1.83	\$45.97	5.27%	5.22%	5.16%	5.11%	5.06%	5.01%	4.96%	9.20%
MEDIAN		\$1.72	\$41.69	5.36%	5.29%	5.23%	5.16%	5.09%	5.03%	4.96%	9.18%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, 90-day average as of January 18, 2013

[3] Source: Constant Growth DCF

[4] Equals $[3] - ([3] - [9]) / 6$

[5] Equals $[4] - ([3] - [9]) / 6$

[6] Equals $[5] - ([3] - [9]) / 6$

[7] Equals $[6] - ([3] - [9]) / 6$

[8] Equals $[7] - ([3] - [9]) / 6$

[9] Consensus Economics Inc., Consensus Forecasts, October 8, 2012

[10] Internal rate of return

180-DAY MULTI-STAGE DCF -- U.S. PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Annualized		Growth						GDP	
Company	Ticker	Dividend	Stock Price	Rate, Years	Year 6	Year 7	Year 8	Year 9	Year 10	Growth (perpetuity)	ROE
Consolidated Edison	ED	\$2.46	\$59.63	2.92%	3.26%	3.60%	3.94%	4.28%	4.62%	4.96%	8.76%
NextEra Energy, Inc.	NEE	\$2.64	\$69.60	6.11%	5.91%	5.72%	5.53%	5.34%	5.15%	4.96%	9.23%
Northeast Utilities	NU	\$1.47	\$39.06	7.03%	6.69%	6.34%	6.00%	5.65%	5.31%	4.96%	9.45%
Southern Co.	SO	\$1.96	\$45.18	4.83%	4.85%	4.87%	4.89%	4.92%	4.94%	4.96%	9.47%
Wisconsin Energy	WEC	\$1.36	\$38.50	5.55%	5.45%	5.35%	5.25%	5.16%	5.06%	4.96%	8.81%
Xcel Energy, Inc.	XEL	\$1.08	\$27.83	5.17%	5.14%	5.10%	5.06%	5.03%	4.99%	4.96%	9.09%
MEAN		\$1.83	\$46.63	5.27%	5.22%	5.16%	5.11%	5.06%	5.01%	4.96%	9.13%
MEDIAN		\$1.72	\$42.12	5.36%	5.29%	5.23%	5.16%	5.09%	5.03%	4.96%	9.16%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, 180-day average as of January 18, 2013

[3] Source: Constant Growth DCF

[4] Equals $[3] - ([3] - [9]) / 6$

[5] Equals $[4] - ([3] - [9]) / 6$

[6] Equals $[5] - ([3] - [9]) / 6$

[7] Equals $[6] - ([3] - [9]) / 6$

[8] Equals $[7] - ([3] - [9]) / 6$

[9] Consensus Economics Inc., Consensus Forecasts, October 8, 2012

[10] Internal rate of return

30-DAY MULTI-STAGE DCF -- CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Canadian Utilities Limited	CU	\$1.94	\$74.76	7.75%	7.13%	6.51%	5.90%	5.28%	4.66%	4.04%	7.46%
Emera Inc.	EMA	\$1.40	\$35.60	7.48%	6.90%	6.33%	5.76%	5.19%	4.61%	4.04%	9.09%
Enbridge Inc.	ENB	\$1.26	\$44.49	10.61%	9.52%	8.42%	7.33%	6.23%	5.14%	4.04%	8.47%
Fortis Inc.	FTS	\$1.24	\$34.00	4.44%	4.37%	4.30%	4.24%	4.17%	4.11%	4.04%	7.93%
TransCanada Corporation	TRP	\$1.76	\$48.09	8.99%	8.16%	7.34%	6.51%	5.69%	4.86%	4.04%	9.19%
Valener Inc.	VNR	\$1.00	\$16.15	7.00%	6.51%	6.01%	5.52%	5.03%	4.53%	4.04%	11.67%
MEAN		\$1.43	\$42.18	7.71%	7.10%	6.49%	5.87%	5.26%	4.65%	4.04%	8.97%
MEDIAN		\$1.33	\$40.04	7.61%	7.02%	6.42%	5.83%	5.23%	4.64%	4.04%	8.78%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, 30-day average as of January 18, 2013

[3] Source: Constant Growth DCF

[4] Equals $[3] - ([3] - [9]) / 6$

[5] Equals $[4] - ([3] - [9]) / 6$

[6] Equals $[5] - ([3] - [9]) / 6$

[7] Equals $[6] - ([3] - [9]) / 6$

[8] Equals $[7] - ([3] - [9]) / 6$

[9] Consensus Economics Inc., Consensus Forecasts, October 8, 2012

[10] Internal rate of return

90-DAY MULTI-STAGE DCF -- CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Canadian Utilities Limited	CU	\$1.94	\$70.53	7.75%	7.13%	6.51%	5.90%	5.28%	4.66%	4.04%	7.66%
Emera Inc.	EMA	\$1.40	\$34.92	7.48%	6.90%	6.33%	5.76%	5.19%	4.61%	4.04%	9.19%
Enbridge Inc.	ENB	\$1.26	\$42.07	10.61%	9.52%	8.42%	7.33%	6.23%	5.14%	4.04%	8.71%
Fortis Inc.	FTS	\$1.24	\$33.80	4.44%	4.37%	4.30%	4.24%	4.17%	4.11%	4.04%	7.95%
TransCanada Corporation	TRP	\$1.76	\$46.59	8.99%	8.16%	7.34%	6.51%	5.69%	4.86%	4.04%	9.35%
Valener Inc.	VNR	\$1.00	\$16.06	7.00%	6.51%	6.01%	5.52%	5.03%	4.53%	4.04%	11.71%
MEAN		\$1.43	\$40.66	7.71%	7.10%	6.49%	5.87%	5.26%	4.65%	4.04%	9.10%
MEDIAN		\$1.33	\$38.49	7.61%	7.02%	6.42%	5.83%	5.23%	4.64%	4.04%	8.95%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, 90-day average as of January 18, 2013

[3] Source: Constant Growth DCF

[4] Equals $[3] - ([3] - [9]) / 6$

[5] Equals $[4] - ([3] - [9]) / 6$

[6] Equals $[5] - ([3] - [9]) / 6$

[7] Equals $[6] - ([3] - [9]) / 6$

[8] Equals $[7] - ([3] - [9]) / 6$

[9] Consensus Economics Inc., Consensus Forecasts, October 8, 2012

[10] Internal rate of return

180-DAY MULTI-STAGE DCF -- CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Canadian Utilities Limited	CU	\$1.94	\$69.35	7.75%	7.13%	6.51%	5.90%	5.28%	4.66%	4.04%	7.72%
Emera Inc.	EMA	\$1.40	\$34.69	7.48%	6.90%	6.33%	5.76%	5.19%	4.61%	4.04%	9.22%
Enbridge Inc.	ENB	\$1.26	\$40.87	10.61%	9.52%	8.42%	7.33%	6.23%	5.14%	4.04%	8.84%
Fortis Inc.	FTS	\$1.24	\$33.46	4.44%	4.37%	4.30%	4.24%	4.17%	4.11%	4.04%	7.99%
TransCanada Corporation	TRP	\$1.76	\$45.46	8.99%	8.16%	7.34%	6.51%	5.69%	4.86%	4.04%	9.47%
Valener Inc.	VNR	\$1.00	\$15.91	7.00%	6.51%	6.01%	5.52%	5.03%	4.53%	4.04%	11.78%
MEAN		\$1.43	\$39.96	7.71%	7.10%	6.49%	5.87%	5.26%	4.65%	4.04%	9.17%
MEDIAN		\$1.33	\$37.78	7.61%	7.02%	6.42%	5.83%	5.23%	4.64%	4.04%	9.03%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, 180-day average as of January 18, 2013

[3] Source: Constant Growth DCF

[4] Equals $[3] - ([3] - [9]) / 6$

[5] Equals $[4] - ([3] - [9]) / 6$

[6] Equals $[5] - ([3] - [9]) / 6$

[7] Equals $[6] - ([3] - [9]) / 6$

[8] Equals $[7] - ([3] - [9]) / 6$

[9] Consensus Economics Inc., Consensus Forecasts, October 8, 2012

[10] Internal rate of return

Research

Research Update:

Ontario Power Generation Inc. Rating Lowered To 'BBB+' From 'A-' On Province of Ontario Downgrade; Outlook Stable

Primary Credit Analyst:

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Research Update:

Ontario Power Generation Inc. Rating Lowered To 'BBB+' From 'A-' On Province of Ontario Downgrade; Outlook Stable

Overview

- We are lowering our long-term corporate credit rating on Ontario Power Generation Inc. (OPG) to 'BBB+' from 'A-'.
- We are also affirming our 'A-1(Low)' Canada scale commercial paper rating on OPG.
- The rating action follows the downgrade to the Province of Ontario to 'A+' from 'AA-' on July 6.
- Our "strong" business risk profile and "aggressive" financial risk profile assessments have not changed.
- The stable outlook on OPG reflects our view of the company's 'bbb-' stand-alone credit profile and of the continued "high" likelihood of support from Ontario.

Rating Action

On July 7, 2015, Standard & Poor's Ratings Services lowered its long-term corporate credit ratings on Ontario Power Generation Inc. (OPG) to 'BBB+' from 'A-'. The outlook is stable. At the same time, Standard & Poor's affirmed its 'A-1(Low)' Canada scale commercial paper rating on OPG.

Rationale

The downgrade follows that on the Province of Ontario, OPG's parent, to 'A+' from 'AA-' on July 6. We link the rating on OPG to that on Ontario through our government-related entities (GRE) criteria. The combination of the 'A+' rating on Ontario, OPG's 'bbb-' stand-alone credit profile (SACP), and our continuing view of a "high" likelihood of support from the province results in a one-notch downgrade of the rating on OPG to 'BBB+'. From our perspective, the "high" likelihood the province would provide timely and sufficient extraordinary support to OPG in the event of financial distress has not changed.

Our assessment of OPG's business risk profile is still "strong," reflecting the utility's strong market position (which accounted for more than 50% of Ontario's electricity generation in 2014); its large and diverse generation portfolio comprising nuclear, hydroelectric, and thermal assets; and a supportive regulatory framework. We expect OPG will continue to generate about 90% of its EBITDA from regulated sources, recover its fixed and variable cost

in a timely manner, and earn a moderate return on capital assets. In addition, we believe the recent addition of 48 hydroelectric previously merchant generation facilities into its regulated portfolio reduces cash-flow volatility and further supports the utility's strong business risk profile.

Our assessment of OPG's financial risk profile is unchanged at "aggressive." We expect the company to continue with a number of projects that require significant capital spending, about C\$1.6 billion per year, over the next two years including the Darlington nuclear facility refurbishment plus additional maintenance capital expenditures, which pressures the credit metrics. We forecast adjusted funds from operations (AFFO)-to-debt of 14%-16% for each of 2015 and 2016 before dropping to about 13% in 2017, when the Darlington refurbishment project execution starts.

Our base-case scenario assumes the following:

- OPG will continue to focus on its regulated electricity generation business
- The Ontario Energy Board, the provincial regulator, will continue to operate in a transparent, stable, and predictable manner
- The utility will not experience any adverse regulatory decisions
- OPG will rebase its nuclear and hydroelectric base rates in 2016 and get most of its forecast rate base and capital spending request approved
- The Darlington refurbishment project will incur no material delays and cost overruns

Based on these assumptions, we arrive at the following credit measures:

- AFFO-to-debt of 14%-16% in 2015 and 2016 and about 12%-14% in 2017
- Debt-to-EBITDA of 4x-5x over the next two years

Liquidity

We view OPG's liquidity as "adequate." We expect liquidity sources to exceed uses by more than 1.1x in the next 12 months. In the event of a 10% drop in the company's EBITDA, we also expect liquidity will be sufficient to cover uses. We believe the company has sound relationships with banks. In the event of unexpected financial stress, we expect the utility would scale back on its capital expenditures to preserve the credit metrics.

Principal liquidity sources include:

- Cash available of about C\$610 million in 2015
- FFO of about C\$1.12 billion in 2015
- Committed credit facilities availability of about C\$1.3 billion as of March 2015, including a C\$1.0 billion committed revolving credit facility expiring in May 2020 and a C\$300 million tranche expiring in August 2019

Principal liquidity uses include:

- Debt maturity of about C\$500 million in 2015
- Capital expenditures of about C\$1.7 billion in 2015

Outlook

The stable outlook reflects our view of the 'bbb-' SACP on OPG and that we do not expect the likelihood of government support to change. A one-notch deterioration in either the SACP or the rating on Ontario would not change the final rating on the utility.

Upside scenario

We could take a positive rating action if we expected AFFO-to-debt to be above 13% comfortably and consistently. A one-notch improvement to OPG's SACP, all else being equal with the province, would result in a one-notch upgrade. However, we view this as unlikely during our outlook period given the Ontario regulatory framework and the extent of company's capital spending program.

Downside scenario

We believe a negative rating action on OPG is highly unlikely in the next 24 months given that both the SACP and the rating on Ontario would have to decline one notch. An unexpected change in our view of the relationship between OPG and the province to "moderately high" or lower could also negatively affect the rating. We could lower the SACP to 'bb+' if we expected AFFO-to-debt to fall below 9% for several years. Given the regulatory support OPG enjoys, we view this as unlikely.

Ratings Score Snapshot

Corporate credit rating: BBB+/Stable/--

Business risk: Strong

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Satisfactory

Financial risk: Aggressive

- Cash flow/Leverage: Aggressive

Anchor: bb+

Modifiers

- Diversification/Portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Financial policy: Neutral (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Positive (+1 notch)

Stand-alone credit profile: bbb-

Filed: 2016-10-26

EB-2016-0152

Exhibit L, Tab 3.1

Schedule 20 VECC-008

Attachment 2

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- Likelihood of government support: High (+2 notch from SACP)

Related Criteria And Research

Related Criteria

- Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012

Ratings List

Rating Lowered

	To	From
Ontario Power Generation Inc. Corporate credit rating	BBB+/Stable/--	A-/Negative/--

Rating Affirmed

Ontario Power Generation Inc. Commercial paper Canada scale	A-1 (Low)

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RatingsDirect®

Summary:

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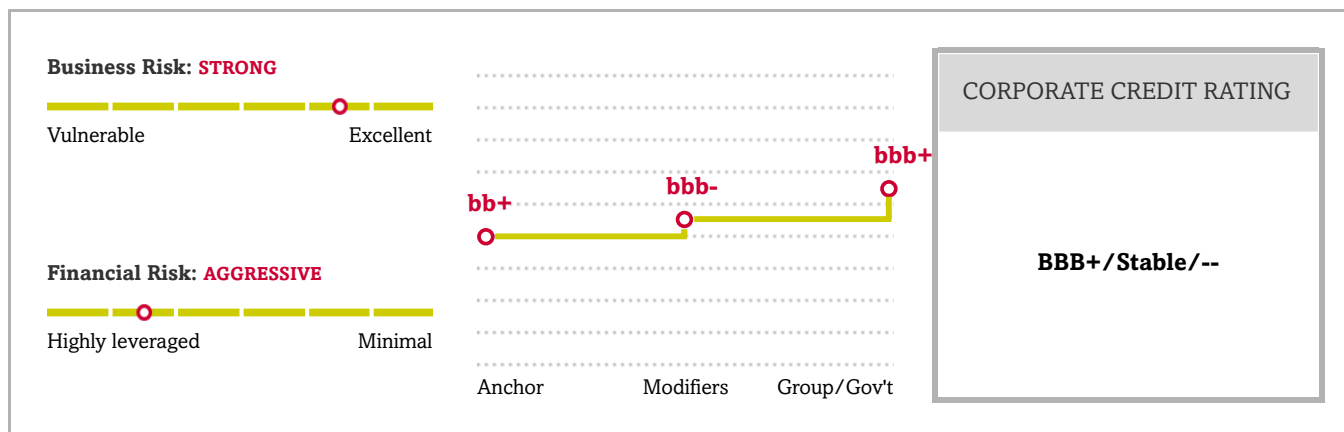
Government Influence

Ratings Score Snapshot

Related Criteria And Research

Summary:

Ontario Power Generation Inc.



Rationale

Business Risk: Strong	Financial Risk: Aggressive
- Ontario Power Generation Inc.'s (OPG) dominant position in a strong market and a diversified economy - Regulatory support for the company's nuclear assets and the bulk of its hydroelectric assets - A diversified portfolio of power-generating assets - Low-cost hydroelectric assets with diversified river systems	- Stable, regulated cash flow - Overall weak cash flow metrics - Large capital programs over next several years

Outlook: Stable

The stable outlook reflects our view of the 'bbb-' stand-alone credit profile (SACP) on Ontario Power Generation Inc. (OPG) and that we do not expect the likelihood of extraordinary government support to change. A one-notch deterioration in either the SACP or our rating on the Province of Ontario would not change our rating on the utility.

Downside scenario

We believe a negative rating action on OPG is unlikely during our two-year outlook period given that both the SACP and our rating on Ontario would have to decline one notch. An unexpected change in our view of the relationship between OPG and the province to "moderately high" or lower could also negatively affect the rating. We could lower the SACP to 'bb+' if we expected a sustained drop in adjusted funds from operations (AFFO) -to-debt below 9%. Given the regulatory support OPG benefits, we view this as unlikely.

Upside scenario

We could take a positive rating action if we expected AFFO-to-debt to be above 13% comfortably and consistently. A one-notch improvement to OPG's SACP, all else being equal with the province, would result in a one-notch upgrade. However, we view this as unlikely during our outlook period given the Ontario regulatory framework and the extent of the company's capital spending program, including the multi-billion Darlington nuclear plant refurbishment.

S&P Global Ratings Base-Case Scenario

OPG is an Ontario-based electricity generation company whose principal business is in electricity generation and sale in the Province of Ontario. OPG supplies about half of the electricity in Ontario and is wholly owned by the province.

Assumptions	Key Metrics								
- OPG will continue to focus on its regulated electricity generation business - The Ontario Energy Board, the provincial regulator, will continue to operate in a transparent, stable, and predictable manner - The utility will not experience any adverse regulatory decisions - OPG filed a five-year rate application for 2017-2021; with regulated nuclear rates under the custom incentive regulation and the regulated hydroelectric rates under the incentive rate making regulation, we expect OPG will get most of its revenue requirements approved - The Darlington refurbishment project will incur no material delays and cost overruns	<table><tr><th></th><th>2015A</th><th>2016E</th><th>2017E</th></tr><tr><td>AFFO/debt (%)</td><td>16.9</td><td>12-14</td><td>13-14</td></tr></table> AFFO--Adjusted funds from operations. A--Actual. E--Estimated.		2015A	2016E	2017E	AFFO/debt (%)	16.9	12-14	13-14
	2015A	2016E	2017E						
AFFO/debt (%)	16.9	12-14	13-14						

Business Risk: Strong

Our assessment of OPG's strong business risk profile reflects the utility's strong market position (which accounted for about 50% of Ontario's electricity generation in 2015) and a supportive regulatory framework. We expect OPG will continue to generate about 95% of its EBITDA from regulated sources, recover prudently incurred fixed and variable cost in a timely manner, and earn a moderate return on capital assets.

In addition, OPG has a diverse portfolio of generation assets comprising four nuclear (including Bruce), 65 hydro-electric, two biomass stations, three thermal stations, and one wind turbine asset; therefore, OPG is not dependent on a single or few generation assets. The hydro-electric assets are subject to hydrology risk; however, this is mitigated by the multiple river systems.

Further supporting the strong business risk profile is that OPG's service territory, the Province of Ontario, has a very strong and diversified economy with modest population growth supporting electricity consumption. However, this is offset by the ongoing demand conservation programs resulting in ratepayers being more cautious about conserving energy and reduces electricity consumption.

Due to the nature of the business, OPG does not deal directly with ratepayers and does not have a large and diverse customer base. OPG's main counterparty is the Independent Electricity System Operator, a Crown corporation, which remits monthly electricity sales revenue to OPG in the subsequent month.

Financial Risk: Aggressive

We assess OPG's financial risk profile as aggressive. For the company, we use the medial volatility table when

assessing the cash flows to reflect the supportive regulatory framework and that virtually all of OPG's cash flows come from the higher end of the utility risk spectrum in electricity generation compared with that of transmission and distribution.

The company has a significant capital program over the next few years of about C\$1.8 billion per year, including the Darlington nuclear facility refurbishment plus additional maintenance capital spending. We believe the high amount of capital spending will pressure the credit metrics. Given the Darlington refurbishment project execution starts in 2016, we forecast AFFO-to-debt of about 12%-14% during our outlook period.

Liquidity: Adequate

OPG's liquidity is considered as adequate in our view. We expect liquidity sources to exceed uses by more than 1.1x over the next 12 months. In the event of a 10% drop in the company's EBITDA, we also expect there are sufficient liquidity sources to cover uses. In our view, the company has sound relationships with banks. In the event of unexpected financial stress, we expect the utility would scale back on its capital expenditures to preserve the credit metrics.

Principal Liquidity Sources	Principal Liquidity Uses
- Cash available of about C\$460 million in 2016 - Cash FFO of about C\$1.45 billion in 2016 - Committed credit facilities availability total of about C\$1.7 billion in 2016, of which about C\$1.0 billion matures in 2021 and C\$700 million matures in December 2017	- Debt maturity of about C\$273 million in 2016 - Capital expenditures of about C\$2.0 billion in 2016

Other Modifiers

We applied a positive comparable rating analysis modifier to OPG to reflect the company's dominant market position in Ontario as it contributes about 50% of the Province of Ontario's power generation. In addition, the company also benefits from a high proportion of regulated cash flow, providing predictability and stability in its electricity generation business. Other modifiers have no impact on the rating.

Government Influence

We believe there is a high likelihood that OPG's owner, the Province of Ontario, would provide timely and sufficient extraordinary support to the company in the event of financial distress. This is based on our assessment of a very strong link and an important role in accordance with our government-related entity criteria. Our assessment further reflects our view that:

- OPG's role to the Province of Ontario is important because it supplies more than 50% of the province's electricity

usage. In addition, OPG provides an essential infrastructure to Ontario and its activities relates to an important public policy role (energy and environmental policies).

- OPG has a very strong link with Province of Ontario because Ontario owns 100% of OPG (strong shareholder) and has a track record of providing support to OPG (through the Ontario Electricity Financial Corporation).

The high likelihood of extraordinary government support provides a two-notch rating enhancement to OPG's 'bbb-' SACP.

Ratings Score Snapshot

Corporate Credit Rating

BBB+/Stable/--

Business risk: Strong

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Satisfactory

Financial risk: Aggressive

- **Cash flow/Leverage:** Aggressive

Anchor: bb+

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Positive (+1 notch)

Stand-alone credit profile : bbb-

- **Likelihood of government support:** High (+2 notches from SACP)

Related Criteria And Research

Related Criteria

- Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- National And Regional Scale Credit Ratings, Sept. 22, 2014
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013

- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	Intermediate	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

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Rating Report

Ontario Power Generation Inc.



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Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Unsecured Debt	A (low)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

On April 6, 2016, DBRS Limited (DBRS) confirmed the Issuer Rating and Unsecured Debt rating of Ontario Power Generation Inc. (OPG or the Company) at A (low), and the Commercial Paper (CP) rating at R-1 (low), all with Stable trends. The confirmation was largely based on the continuing financial support from the Company's shareholder, the Province of Ontario (the Province; rated AA (low) by DBRS). The Province, through its agent the Ontario Electricity Financial Corporation (OEFC; rated AA (low) by DBRS), provides most of OPG's financing (approximately 63% of total debt). The Company's remaining debt is in the form of non-recourse project finance debt.

The Province announced in January 2016 that OPG will be moving forward with the refurbishment of the Darlington Nuclear Generating Station (the Darlington Refurbishment). The project has a final budget of \$12.8 billion, and the refurbishment of the first unit is scheduled to begin in October 2016, with the last unit to be in-service by 2026. DBRS believes that given the complexity and scale of the Darlington Refurbishment, there is significant execution risk as well as the potential for cost overruns. The high capital expenditures (capex) required, albeit spread over a ten-year period, in addition to ongoing maintenance capex (total capex forecast of approximately \$2 billion for 2016), are expected to pressure OPG's key credit metrics. Although the Company's cash flow-to-debt and debt-to-capital ratios have remained strong, DBRS expects leverage to increase to approximately 40% during this period of high capex. Additionally, profitability for OPG continues to be challenged as evidenced by the

negative EBIT-interest coverage ratio for the year. DBRS notes that while the in-service of the Lower Mattagami River Project (LMRP) and the prescription of 48 previously unregulated hydroelectric facilities to regulated rates in late 2014 have helped improve OPG's EBITDA, the Company's reported corporate return on equity (ROE; 4.1% in 2015) remains far below the approved ROE of 9.3%. This has largely been due to the high cost base of OPG, which has resulted in several disallowances by the Ontario Energy Board (OEB) for the Company to recover forecasted compensation expenses.

OPG plans to submit a five-year application with the OEB later this year for new regulated rates effective 2017. The OEB has expressed that it expects prices for hydroelectric operations to be based on an incentive regulation (IR) ratemaking methodology, and that prices for nuclear operations be based on a multi-year forecast cost-of-service (COS) approach with IR features. DBRS believes that profitability for OPG could continue to be challenged following a switch to an IR framework, as the introduction of productivity and efficiency targets could further depress earnings. However, through its Business Transformation initiative, OPG has demonstrated its ability to improve efficiency by reducing regular headcount from continuing operations by approximately 2,700 personnel since 2011. Furthermore, earnings should also benefit from the growth in the rate base as Darlington Refurbishment pre-requisite projects are completed, and new regulated rates in 2017.

Financial Information

For the year ended December 31

(CAD millions)	2015	2014	2013	2012	2011
Cash flow/Total debt ¹	33.2%	27.0%	22.9%	20.8%	28.9%
Total debt in capital structure ^{1, 2}	35.9%	36.9%	38.9%	36.9%	36.8%
EBIT gross interest coverage (times) ³	(0.86)	0.24	(1.12)	0.66	0.02
EBITDA gross interest coverage (times) ³	2.89	2.75	2.21	3.15	2.71
(Cash flow - n.w.f.)/Total debt ⁴	27.5%	21.3%	16.5%	13.8%	21.1%

¹ Including operating leases. ² Adjusted for Accumulated Other Comprehensive Income. ³ Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.

⁴ Included nuclear waste funding (n.w.f.) payments as they are not discretionary.

Issuer Description

Ontario Power Generation Inc. is an electricity generating company with a diverse portfolio of over 17,000 megawatts (MW) of in-service generating capacity. The Company is wholly owned by the Province of Ontario.

Rating Considerations

Strengths

1. Support of shareholder (the Province)

The Province indirectly provides OPG with the majority of its long-term funding requirements through the OEFC, a government financing arm for the provincial power companies; however, this debt is not directly guaranteed by the Province. DBRS believes that the Province will continue to support its investment since OPG is a creation of the Province and is integral to fulfilling Ontario's energy needs.

2. Dominant market position in Ontario

OPG's importance in Ontario is demonstrated by the fact that it is the primary electricity generator in the Province, accounting for approximately 51% of electricity produced in Ontario in 2015.

3. Reasonable regulatory framework

The reasonable regulatory framework has allowed the Company to recover prudently incurred costs. However, DBRS notes that the unsuccessful appeal of the OEB's decision to disallow labour compensation costs related to OPG's nuclear operations has increased uncertainty regarding the Company's ability to fully recover its nuclear cost through future regulated prices (refer to the Regulation section for details).

4. Limited nuclear waste management liabilities

As a result of the Ontario Nuclear Funds Agreement (ONFA) with the Province, OPG's exposure relating to nuclear waste management liabilities has been capped at \$5.94 billion (in 1999 dollar terms) for the initial 2.23 million used fuel bundles produced. The Company is, however, responsible for the incremental costs related to the management of used fuel bundles in excess of 2.23 million bundles (2.44 million currently). The Province provides a guarantee for any shortfall between the value of the nuclear fund and the Canadian Nuclear Safety Commission consolidated financial guarantee requirement.

Challenges

1. Significant capex program

OPG has a significant capex program underway (approximately \$2 billion planned for 2016). The Company also faces significant execution risk associated with the Darlington Refurbishment because of the complexity and scale of the project. It is expected that OPG will not undertake any major capex without having financing and a cost-recovery mechanism in place, thus minimizing the financial risks.

2. Nuclear generation risks

Nuclear generation faces higher operating risks than other types of generation because of its complex technology (approximately 57% of OPG's production in 2015). Financial implications of forced outages, especially with older units (e.g., Pickering Nuclear Generating Station), are greater given the high fixed-cost nature of these plants as well as the fact that lost revenues resulting from outages are not recoverable through rates.

3. High cost base

OPG's high cost base has resulted in several disallowances by the OEB. In its decision on OPG's application for 2014 and 2015 rates, the OEB disallowed recovery of \$100 million of compensation costs for each of 2014 and 2015. Additionally, in September 2015, the Supreme Court of Canada upheld the OEB's 2011 decision to disallow \$145 million of forecast nuclear compensation costs for 2011 and 2012. DBRS believes that the inability of OPG to fully recover compensation costs in future regulated prices could have a negative impact on earnings and has affected the Company's ability to achieve its approved ROE. DBRS notes that OPG has been combatting this issue through its Business Transformation initiative, which has reduced headcount by over 2,700 since 2011.

4. Political intervention

OPG is subject to political intervention, largely because of changes in government mandates and policies as well as limits that restrict revenues and earnings should the price of electricity rise quickly. DBRS notes that the Province has committed to having OPG run more autonomously; however, the risk of further government intervention still exists.

Major Projects

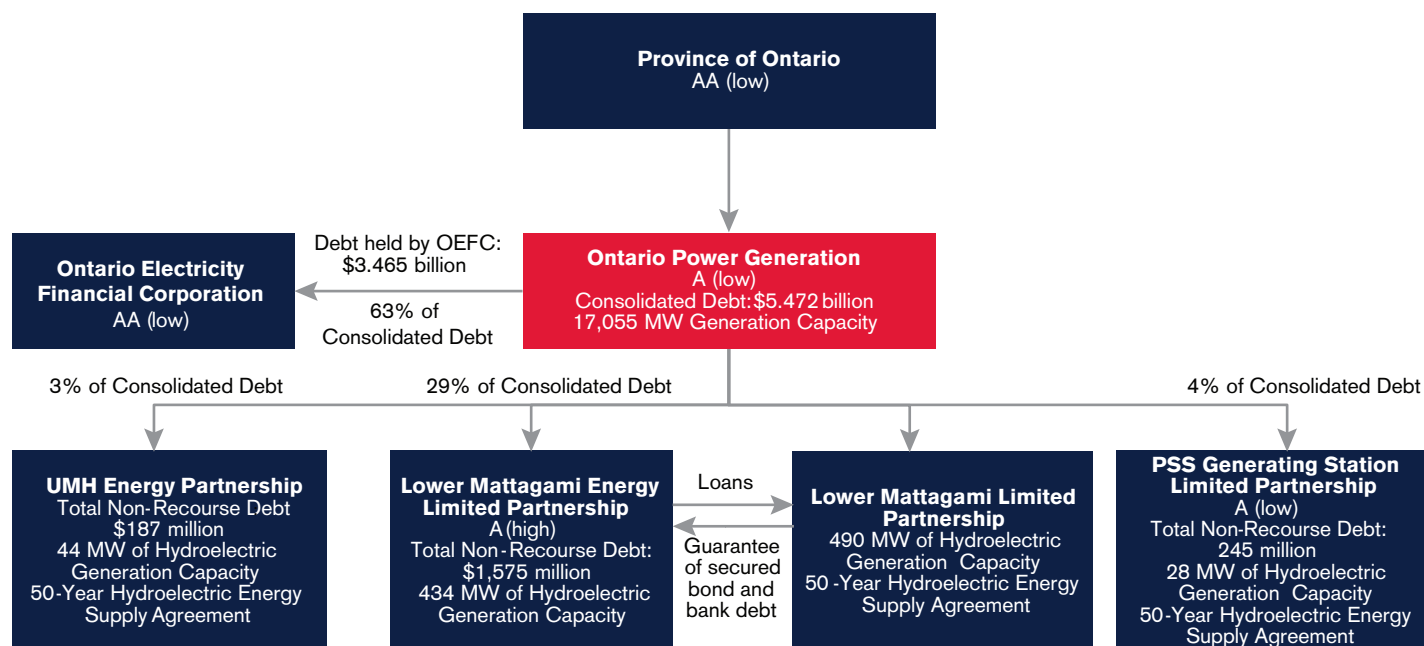
- **Darlington Refurbishment:** The Darlington Refurbishment will extend the operating life of the Darlington Nuclear Generating Station by approximately 30 years. The execution of the refurbishment for the first unit is scheduled to begin in October 2016, with the last unit scheduled to be completed by 2026.
- **Peter Sutherland Sr. Generating Station Project (PSS GS):** The PSS GS is a 28-MW hydroelectric station on the Abitibi River. The project has a 50-year hydro Energy Supply Agreement (ESA) with the Independent Electricity Systems Operator (IESO; rated A (high) by DBRS), which protects it from hydrology and power price risk. Additionally, OPG guarantees PSS GS's debt until the Recourse Release Date (see DBRS's PSS Generating Station LP (New Post Creek) rating report dated October 23, 2015, for more details).
- **Lower Mattagami River Project (LMRP):** All six units of the LMRP were placed in service as of December 31, 2014. This project, which increased the capacity of four generating stations on the Lower Mattagami River by 438 MW, has a 50-year hydroelectric ESA with the IESO, which provides a utility-like COS revenue requirement for energy produced. In addition, OPG guarantees LMRP's debt until the Recourse Release Date (see DBRS's Lower Mattagami Energy Limited Partnership (LMELP) rating report dated June 4, 2015, for more details).
- **Nanticoke Solar Facility:** OPG announced in March 2016 that it has been selected by the IESO to develop a 44-MW solar facility near the Nanticoke Generating Station. Construction will begin once the Company receives the required approvals and contracts.

Project	Estimated Cost (\$ millions)	Spent as of Dec. 31, 2015 (\$ millions)	In-Service Target Date
Darlington Refurbishment	12,800	2,166	2026*
Peter Sutherland Sr. Generating Station	300	95	H2 2017
Lower Mattagami River Project	2,600	2,484	June 2015**

* Four units with staged in-service. Last unit scheduled to be completed by 2026.

** Entire complex placed in-service by December 2014.

Simplified Organizational Chart

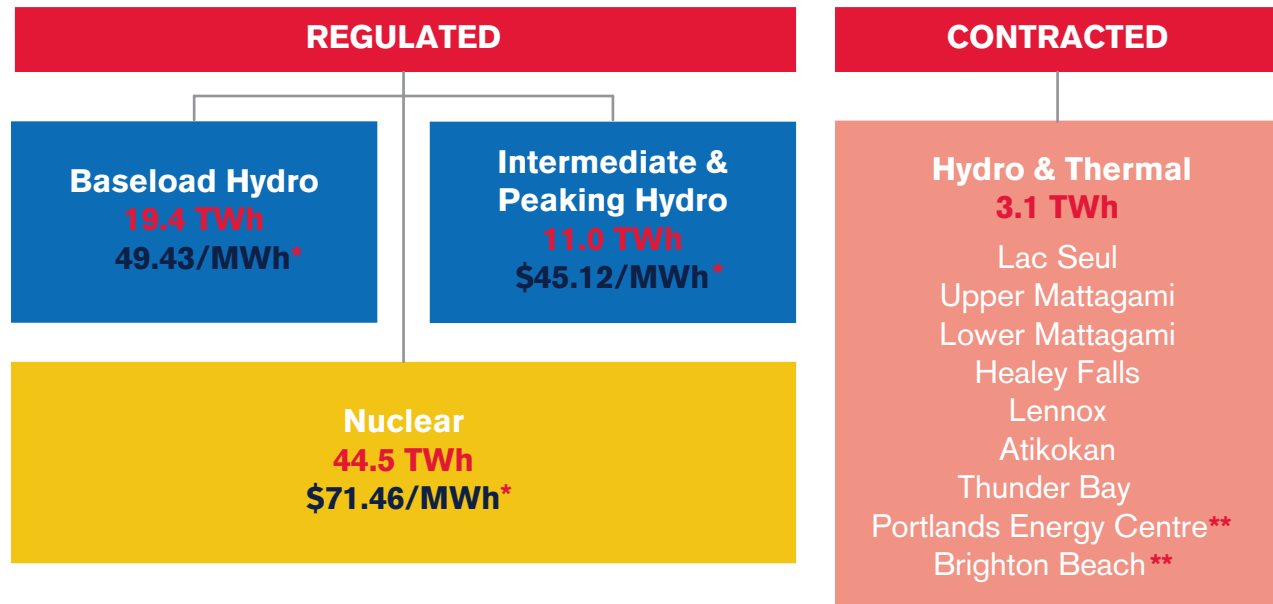


As of December 31, 2015.

Regulation

- OPG benefits from a reasonable regulated environment. As of December 31, 2015, 96% of its installed in-service capacity is regulated.
- OPG, regulated by the OEB under the *Electricity Restructuring Act, 2004 (Ontario)*, is allowed to receive regulated prices for all electricity generated from its nuclear facilities (6,606 MW) as well as most of its hydroelectric power facilities (6,428 MW).
- An amendment to Ontario Regulation 53/05 (O. Reg. 53/05) by the Ministry of Energy brought all of OPG's previously non-regulated hydroelectric facilities not under an ESA with the IESO to be subject to the OEB's regulation effective July 1, 2014. This amendment provided further stability to the Company's credit profile, as a large majority of installed in-service capacity is now regulated.
- In September 2015, the Supreme Court of Canada overturned the Court of Appeal and upheld the OEB's original decision to disallow a portion of the Company's nuclear compensation costs. DBRS believes that the inability of OPG to fully recover its nuclear compensation in future regulated prices could have a negative impact on earnings.
- The OEB issued its decision on OPG's application for Payment Amounts for Prescribed Facilities for 2014 and 2015 in November 2014, approving the following:
 - A 24-month revenue requirement of approximately \$8.1 billion for 2014 and 2015, a reduction of \$934 million from the requested amount.
 - Payment amounts effective November 1, 2014, of \$40.20/megawatt hour (MWh) for previously regulated hydroelectric facilities, \$41.93/MWh for newly regulated hydroelectric facilities and \$59.29/MWh for regulated nuclear facilities.
 - Payment riders for the recovery of OEB-authorized regulatory variance and deferral accounts of \$6.04/MWh for previously regulated hydroelectric facilities and \$1.33/MWh for regulated nuclear facilities, effective January 1, 2015.
 - Deemed capital structure of 55% debt, a change from 53%, with an ROE of 9.36% on regulated base rates for 2014.
- The OEB rejected the previous accrual method of accounting for pension and other post-employment benefit (OPEB) costs for 2014 and 2015 rate setting purposes. OPG will instead include pension and OPEB costs on a cash basis with a deferral account set up to account for the difference. This decreased the Company's revenue requirement by approximately \$600 million. A final position on the accrual or cash method will be determined based on a generic proceeding on pension and OPEB costs.
- Other significant outcomes from this decision included (1) a reduction of \$100 million of compensation costs in each of 2014 and 2015, (2) disallowance of \$88 million related to the Niagara Tunnel Project (\$77 million write-off for OPG with \$1,365 million approved for inclusion into rate base) and (3) a reduction in the revenue requirement of \$70 million from a regulatory tax loss in 2013.
 - OPG subsequently filed an application with the OEB to review and vary the decision in regards to the Niagara Tunnel Project disallowance. The OEB issued a decision in January 2016, reducing the disallowance to \$66 million.
- In December 2014, the Company filed an application to recover the balance in its deferral and variance accounts as of December 31, 2014. OPG was seeking to recover approximately \$1.3 billion through rate riders over the 18-month period from July 2015 to December 2016, and a further \$459 million in a future period.
 - The OEB approved a partial settlement in June 2015 for OPG to recover \$669 million from October 1, 2015, to December 31, 2016, and a further \$816 million in a future period.
 - Subsequently in September 2015, the OEB approved the Company's recovering the remaining applied-for \$263 million.
- OPG plans to file a five-year application with the OEB in 2016 for new regulated rates effective 2017. The OEB has expressed that it expects prices for hydroelectric operations to be based on an IR ratemaking methodology, while prices for nuclear operations be based on a multi-year forecast COS approach with IR features.

OPG's Price Structure



* Rates as of January 1, 2016.

** 50% ownership interest.

For the year ended December 31, 2015.

- OPG sells electricity to consumers through the IESO.
- Regulated operating divisions sell at rates set by the OEB, which include rate riders used for the recovery of nuclear deferral and hydroelectric variance account balances.
- The Contracted Generation Portfolio operating division primarily sells electricity at prices set through ESAs or other long-term contracts with the IESO.

Earnings and Outlook

For the year ended December 31

(CAD millions)	<u>2015</u>	<u>2014</u>	<u>2013</u>	<u>2012</u>	<u>2011</u>
Revenues	5,476	4,963	4,863	4,732	4,964
EBITDA ¹	848	826	638	841	699
EBIT ¹	(252)	72	(325)	177	5
Gross interest expense	293	300	289	267	258
Earning before taxes ¹	(407)	36	(373)	86	(114)
Net income before non-recurring items ¹	(271)	88	(261)	115	48
Reported net income	402	804	135	367	338
Return on equity	-2.8%	1.0%	-3.2%	1.5%	0.6%
Hydroelectric rate base	7,490	7,526	4,829	3,744	3,772
Nuclear rate base	3,659	3,707	3,780	4,133	3,859
Approved regulated ROE	9.30%	9.36%	9.55%	9.55%	9.43%
Achieved regulated ROE	N/A	6.31%	0.46%	4.73%	4.80%

¹ Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.

2015 Summary

- EBITDA in 2015 increased largely because of (1) higher rates approved by the OEB for the regulated segments, including for the 48 hydroelectric facilities that began receiving regulated rates as of November 1, 2014, (2) the in-service of all units of the LMRP in December 2014 and (3) the conversion to biomass for the Atikokan and Thunder Bay generating stations.
 - The increase was offset by higher operating expenses and lower nuclear generation as a result of the four-unit Darlington Vacuum Building Outage, which reduced generation by 3.6 TWh.
- EBIT decreased significantly because of a \$346 million increase in depreciation and amortization. The increase was because of (1) lower depreciation in 2014 caused by higher amounts deferred for that year, (2) higher amortization of regulatory assets and liabilities as OPG began recovering approximately \$1.8 billion in its regulatory variance and deferral accounts and (3) higher depreciation following the in-service of the LMRP and the biomass conversion projects.
- Profitability for OPG remains challenged, as the Company achieved a reported corporate ROE of 4.1% for the year,

significantly below the approved ROE of 9.30%. DBRS notes that the lower ROE is partly due to the Company's capitalization at around 35% debt versus the regulatory capital structure of 55% debt.

2016 Outlook

- EBITDA is expected to remain stable in 2016, as the majority of earnings are expected to continue to be from regulated operations.
- While earnings should benefit from higher rate riders in effect for 2016, net income before non-recurring items is expected to remain weak. Additionally, as the Darlington Refurbishment enters the execution stage, earnings will be negatively affected as each generating unit is temporarily removed from service (first unit in October 2016).
- Earnings volatility going forward will come from (1) adjustments to rate base determined by the OEB and (2) macro factors such as weather, unexpected outages and Ontario's economic conditions.

Financial Profile

	For the year ended December 31				
(CAD millions)	2015	2014	2013	2012	2011
Net income before non-recurring items 3	(271)	88	(261)	115	48
Depreciation & amortization	1,100	754	963	664	694
Deferred income taxes and other	1,097	730	616	305	693
Cash flow (bef. working cap. changes)	1,926	1,572	1,318	1,084	1,435
Nuclear waste funding	(361)	(351)	(383)	(380)	(422)
Dividends paid	0	0	0	0	0
Capital expenditures	(1,376)	(1,545)	(1,568)	(1,427)	(1,145)
Free cash flow (bef. working cap. changes)	189	(324)	(633)	(723)	(132)
Changes in non-cash working cap. items	(100)	212	239	172	166
Net free cash flow	89	(112)	(394)	(551)	34
Long-term investments	(180)	0	0	24	0
Proceeds on asset sales	3	0	0	0	7
Net equity change	0	0	0	0	0
Net debt change	(33)	165	543	310	334
Other	(25)	(5)	0	0	(14)
Change in cash	(146)	48	149	(217)	361
Total debt	5,697	5,730	5,657	5,114	4,804
Cash & equivalents	464	610	562	413	630
Cash flow/Total debt 1	33.2%	27.0%	22.9%	20.8%	28.9%
Total debt in capital structure 1, 2	35.9%	36.9%	38.9%	36.9%	36.8%
EBIT gross interest coverage (times) 1, 3	(0.79)	0.29	(1.05)	0.71	0.12
(Cash flow - n.w.f.)/Total debt 4	27.5%	21.3%	16.5%	13.8%	21.1%
Dividend payout ratio	0.0%	0.0%	0.0%	0.0%	0.0%

1 Including operating leases. **2** Adjusted for Accumulated Other Comprehensive Income. **3** Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.
4 Included nuclear waste funding (n.w.f.) payments as they are not discretionary.

2015 Summary

- OPG's debt-to-capital and cash flow-to-debt ratios were strong for the current rating category; however, the Company's EBIT-interest coverage ratio remained weak.
- Cash flow from operations increased because of higher cash receipts from generation following the prescription of the 48 previously non-regulated hydroelectric facilities for regulated rates, and the in-service of the LMRP and biomass conversion projects.
- Capex of \$1.4 billion was lower following the completion of the above-mentioned projects. This was offset by construction starting on the PSS GS and continued work for the Darlington Refurbishment project.
- No dividend payments were made to the Province during this period of high capex requirements.
- OPG generated positive free cash flow in 2016, as cash flow from operations were sufficient to cover all expenditures.
- The Company repaid a \$500 million note to the OEFC by using cash on hand. PSS GS issued \$245 million of bonds,

of which \$180 million was invested in a structured deposit note with staggered maturity dates. Debt issued by PSS GS, which is guaranteed by the Company, will become non-recourse to OPG once the project is completed and certain requirements are met.

2016 Outlook

- OPG has planned capex of \$2 billion for 2016, including approximately \$1 billion for the Darlington Refurbishment project.
- As the Company continues to execute its large capex program, DBRS expects OPG to generate a free cash flow deficit in 2016. This deficit is expected to be financed with debt and cash on hand. As a result, leverage is expected to increase to nearly 40% over the next few years. DBRS expects the Company to maintain its strong debt-to-capital and cash flow-to-debt ratios in order to offset the weaker EBIT-interest coverage ratio.
- DBRS expects the Province to continue to forego dividends during the Company's large capex program.

Long-Term Debt Maturities and Credit Facilities

Long-term Debt

As at December 31, 2015

(CAD millions)	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>Thereafter</u>	<u>Total</u>
Long-term Debt	273	1,103	398	368	663	2,667	5,472
	5%	20%	7%	7%	12%	49%	100%

Maturity Profile

- The majority of the long-term debt issued at the parent level (approximately \$3.465 billion) is held by the OEFC, which is wholly owned by the Ontario government. As a result, DBRS does not expect any material refinancing risk.
- The Company's maturity profile is fairly spread out over the next five years. A modest maturity is expected in 2017 when \$900 million of senior notes held by the OEFC come due; however, refinancing risk is expected to be manageable.
- In October 2015, PSS GS issued senior secured bonds totalling \$245 million with a maturity date of 2067 and an effective interest rate of 4.90%.

Credit Facilities as at December 31, 2015 (CAD millions)

Bank facilities	Maturity	Amount	Outstanding	Available
Committed credit facility - Tranche 1	20-May-20	500	0	500
Committed credit facility - Tranche 2	20-May-20	500	0	500
Short-term uncommitted credit facilities	Demand	456	384	72
Short-term uncommitted overdraft facilities	Demand	25	0	25
Lower Mattagami River Project - Tranche 1	17-Aug-20	300	225	75
Lower Mattagami River Project - Tranche 2	17-Aug-16	200	0	200
UMH Energy Partnership credit facilities	15-Oct-15	16	14	2
UMH Energy Partnership overdraft facilities	15-Oct-15	8	0	8
Total		2,005	623	1,382

Liquidity

- OPG has a reasonable liquidity profile.
- The Company has a \$1 billion CP program backed by two tranches of bank facilities (extended due dates of May 20, 2020). All committed bank facilities were unused as at December 31, 2015.
- As at December 31, 2015, OPG had issued \$384 million of letters of credit, of which about \$345 million was attributed to its supplementary pension plan.
- The Company has separate credit facilities provided by the OEFC for corporate and project financing, which DBRS views as adequate for working capital purposes.

Company Profile

Generation Portfolio

As at December 31, 2015

	Percent %	Capacity (MW)
Nuclear		
Darlington	21%	3,512
Pickering A	6%	1,030
Pickering B	12%	2,064
	39%	6,606
Thermal		
Atikokan (Biomass)	1%	205
Thunder Bay (Biomass)	1%	153
Portlands Energy Centre 1	2%	275
Brighton Beach 1	2%	280
Lennox (Dual oil & gas)	12%	2,100
	18%	3,013
Hydroelectric		
Contracted 2	6%	1,006
Regulated	38%	6,428
	44%	7,434
Other (Wind) 3	0%	2
Total Capacity	100%	17,055

1 Represents OPG's share of in-service generation. **2** Includes plants under an ESA or a long-term contract with the IESO. **3** One wind-power turbine.

- OPG is the largest generator of electricity in Ontario.
- In 2015, OPG generated 78.0 terawatt hours of electricity with total in-service capacity of 17,055 MW on December 31, 2015.
- OPG partnerships consist of the following:
 - OPG and ATCO Power Canada Ltd. co-own the Brighton Beach Generating Station, a 580-MW natural gas-fired generating station.
 - OPG and TransCanada Energy Ltd. jointly own the Portlands Energy Centre, a 550-MW natural gas-fired generating station.
 - OPG owns the Bruce A and Bruce B nuclear generating stations, which are leased on a long-term basis to Bruce Power Limited Partnership.
 - OPG and the Lac Seul First Nation (LSFN) jointly own the Lac Seul Generating Station, with LSFN owning 25% of the facility.
 - OPG and the Moose Cree First Nation (MCFN), through its wholly owned subsidiary Amisk-oo-Skow Finance Corporation, jointly own the Little Long, Harmon, Kipling and Smoky Falls generating stations, with MCFN owning 25% of the facilities.

Ontario Power Generation Inc.

Balance Sheet

Balance Sheet				Dec. 31			
(CAD millions)	2015	2014	2013		2015	2014	2013
Assets				Liabilities & Equity			
Cash & equivalents	464	610	562	S.T. borrowings	225	0	32
Accounts receivable	545	482	402	Accounts payable	1,228	1,151	1,026
Inventories	440	428	485	Current portion L.T.D.	273	503	5
Regulatory assets	628	167	306	Regulatory liabilities	26	5	16
Prepaid expenses & other	313	161	224	Deferred revenue & other	78	36	26
Total Current Assets	2,390	1,848	1,979	Total Current Liab.	1,830	1,695	1,105
Net fixed assets	20,595	17,593	16,738	Long-term debt	5,199	5,227	5,620
Intangibles	98	76	59	Deferred income taxes	890	828	565
Nuclear removal/waste mgmt. funds	15,121	14,354	13,471	Pension & post-retirement benefits	5,682	6,620	5,369
Regulatory assets	5,279	7,024	5,094	Nuclear removal/waste mgmt. funds	20,169	17,028	16,257
Investments, materials & other	819	750	750	Regulatory liabilities	0	0	0
				Payables & other L.T. liab.	487	780	841
				Shareholders' equity	10,045	9,467	8,334
Total Assets	44,302	41,645	38,091	Total Liab. & SE	44,302	41,645	38,091

For the year ended December 31

Balance Sheet & Liquidity & Capital Ratios

	2015	2014	2013	2012	2011
Current ratio	1.31	1.09	1.79	1.91	1.62
Total debt in capital structure	36.2%	37.7%	40.4%	39.3%	38.6%
Total debt in capital structure 1, 2	35.9%	36.9%	38.9%	36.9%	36.8%
Cash flow/Total debt	33.8%	27.4%	23.3%	21.2%	29.9%
Cash flow/Total debt 1	33.2%	27.0%	22.9%	20.8%	28.9%
(Cash flow - dividends)/Capex (times)	1.40	1.02	0.84	0.76	1.25
(Cash flow - n.w.f.)/Total debt 4	27.5%	21.3%	16.5%	13.8%	21.1%
Dividend payout ratio	0.0%	0.0%	0.0%	0.0%	0.0%

Coverage Ratios (times)

EBIT gross interest coverage 3	(0.86)	0.24	(1.12)	0.66	0.02
EBIT gross interest coverage 1, 3	(0.79)	0.29	(1.05)	0.71	0.12
EBITDA gross interest coverage 3	2.89	2.75	2.21	3.15	2.71
Fixed-charges coverage 3	(0.86)	0.24	(1.12)	0.66	0.02

Profitability Ratios

EBITDA margin 3	15.5%	16.6%	13.1%	17.8%	14.1%
EBIT margin 3	-4.6%	1.5%	-6.7%	3.7%	0.1%
Profit margin 3	-5.0%	1.8%	-5.4%	2.4%	1.0%
Return on equity 3	-2.8%	1.0%	-3.2%	1.5%	0.6%
Return on capital 1, 2, 3	-0.8%	1.4%	-1.0%	1.6%	1.3%

1 Including operating leases. **2** Adjusted for Accumulated Other Comprehensive Income. **3** Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.
4 Included nuclear waste funding (n.w.f.) payments as they are not discretionary.

Rating History

	Current	2015	2014	2013	2012	2011
Issuer Rating	A (low)	A (low)	A (low)	A (low)	A (low)	NR
Unsecured Debt	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Previous Action

- Confirmed March 24, 2015.

Commercial Paper Limit

- \$1 billion.

Previous Report

- *Ontario Power Generation*, Rating Report, March 24, 2015.

Notes:

All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrs.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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VECC Interrogatory #9

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Reference: C1/T1/S1

Pre-amble: In the 2016 Ontario budget announcement found at <http://www.fin.gov.on.ca/en/budget/ontariobudgets/2016/bk9.html>, the province stated:

The Province remains committed to building a cleaner and more sustainable energy system for all Ontarians while reducing electricity system cost pressures. Since 2003, more than \$34 billion has been invested in cleaner energy generation in Ontario, with Hydro One investing about \$15 billion in modern transmission and distribution infrastructure. Other initiatives include:

- Pursuing the continued operation of the Pickering Nuclear Generating Station beyond 2020 up to 2024. By doing this, Ontario Power Generation (OPG) would protect 4,500 jobs across the Durham region, avoid eight million tonnes of GHG emissions, and save Ontario electricity consumers up to \$600 million.
 - Moving forward with OPG's refurbishment of the four units at the Darlington Nuclear Generating Station. The Independent Electricity System Operator has updated its contract with Bruce Power to refurbish six nuclear units, in addition to two already refurbished units at the Bruce nuclear site. Together, this secures over 9,800 megawatts (MW) of affordable, reliable and emission-free power.
- a) Please confirm that in the Ontario Government's infrastructure programme it includes the costs of the Darlington refurbishment programme as provincial government expenditures.
 - b) Please indicate whether any of the generating plants in the proxy sample are instructed by their owners to follow non-financial objectives such as preserving 4,500 jobs and if their owners put out a release with titles similar to that of Ontario's "Jobs for today and tomorrow". In Concentric's judgement is such an attitude by the shareholder consistent with the stand alone principle.
 - c) Please indicate the capital structure and allowed ROE for the following 100% provincially owned Canadian electric utilities: New Brunswick Power, Manitoba Hydro Electric System, Saskatchewan Power and BC Hydro.
 - d) Please explain in detail why the equivalent 100% owned Canadian electric companies are not a better reference point for a fair capital structure than the US

1 private non-government owned entities, particularly since S&P rates the two
2 entities (electric company and province) the same.

3
4 e) Is Concentric aware that NB Power also has a CANDU nuclear reactor at Point
5 LePreau?
6
7

8 **Response**
9

10 The following response was provided by Concentric Energy Advisors:
11

12 a) Concentric's assessment of OPG's risk profile was performed on a stand-alone basis,
13 consistent with the Board's application of the stand-alone principle in prior OPG payment
14 amount application proceedings. Specifically, as noted in Concentric's report (page 8),
15 the Board stated in EB-2007-0905 that "[t]he stand-alone principle is a long-established
16 regulatory principle," and that "Provincial ownership will not be a factor to be considered
17 by the Board in establishing capital structure." As such, Concentric did not evaluate how
18 the Ontario Government accounts for the Darlington refurbishment program as such an
19 evaluation was not relevant to the analysis.
20

21 b) It is not Concentric's understanding that OPG has been instructed to follow non-financial
22 objectives. Concentric is not aware of any specific examples of generating plants in the
23 proxy sample being instructed by their owners to follow objectives such as preserving
24 4,500 jobs or if their owners have put out releases with titles similar to that of Ontario's
25 "Jobs for today and tomorrow." Many of the generating plants in the proxy group,
26 however, operate in states or regions in which their owners must comply with legislative
27 or regulatory policies such as renewable energy portfolio standards that may be based on
28 objectives that are not related directly to the profitability of the plants. In addition, job
29 preservation and creation is a common benefit cited for large energy-related construction
30 projects.
31

32 As stated in response to part a), the stand-alone principle is a "long-established
33 regulatory principle," not a reflection of an owner's "attitude." Therefore, Concentric finds
34 the shareholder's statements in its press release to be neither consistent nor inconsistent
35 with that regulatory principle.
36

37 c) Please see the table below. As noted in the table, and unlike OPG, the rates of New
38 Brunswick Power, Manitoba Hydro and Saskatchewan Power are not set based on
39 traditional authorized cost of capital parameters, nor were they as of the time that OPG's
40 initial cost of service payment amounts proceeding was decided (e.g., EB-2007-0905 in
41 November, 2008).

1

Utility	Capital Structure (Debt/Equity)	Allowed ROE (%)
New Brunswick Power ¹	N.A.	N.A.
Manitoba Hydro Electric System ²	N.A.	N.A.
Saskatchewan Power ³	N.A.	N.A.
BC Hydro	70/30 ⁴	11.84% ⁵

2

- ¹ New Brunswick Power Corporation's ("NB Power's") rates are not set based on traditional authorized cost of capital parameters. Rather, the New Brunswick Energy and Utilities Board authorizes a revenue requirement that includes a forecasted amount of net income. In addition, NB Power has a goal of achieving a 20% debt-to-capital ratio. For example, per the New Brunswick Energy and Utilities Board, "[f]or the fiscal year 2016/17, the Board approves the amount of \$92.4 million for Net Income and is satisfied that this permits NB Power to continue to move towards its target of a 20% equity ratio." See, New Brunswick Energy and Utilities Board Decision in the Matter of an Application by New Brunswick Power Corporation Pursuant to Subsection 103(1) of the *Electricity Act*, S.N.B. 2013, c.7, for approval of the schedules of the rates for the fiscal year commencing April 1, 2016, July 21, 2016, at 14. In NB Power's previous rate case, which was decided in 1993, the New Brunswick Energy and Utilities Board applied a "return on equity test," using the embedded cost of debt as an appropriate rate of return on NB Power's equity. Specifically, the New Brunswick Energy and Utilities Board evaluated whether the approved amount of net income for NB Power would exceed the amount required to satisfy the Board's return on equity test, interest coverage test, and debt to equity ratio test. See, New Brunswick Energy and Utilities Board Decision in the Matter of an Application by New Brunswick Power Corporation for Approval of Changes in its Charges, Rates and Tolls, April 23, 1993, at 8 and 45.
- ² Manitoba Hydro-Electric Board's ("Manitoba Hydro's") rates are not set based on traditional authorized cost of capital parameters. Manitoba Hydro sets rates based on the objectives of recovering its cost of service and achieving a target capital structure of 75/25 debt/equity. See, e.g., Manitoba Public Utilities Board Order 90/08, June 30, 2008, at 17, and Manitoba Public Utilities Board Order 73/15, July 24, 2015, at 51..
- ³ Saskatchewan Power's ("SaskPower's") rates are not set based on traditional authorized cost of capital parameters. SaskPower does, however, have a target debt level of 60-75% and a target ROE of 8.5%. Per SaskPower, "[i]n recent years, SaskPower has attempted to cap its rate increases at 5% per year. The result has been that the Corporation has absorbed some of the required rate adjustments through increased debt rather than passing costs on immediately to [its] customers. These constraints on rate increases combined with SaskPower's capital program have resulted in SaskPower's debt level reaching the upper limit of [its] 60-75% target," and, "SaskPower's long-term ROE target is 8.5%..." SaskPower Rate Application 2016 and 2017, June 2, 2016, at 14.
- ⁴ Equal to BC Hydro's "deemed equity" from its 2015 to 2016 revenue requirements application. See, BC Hydro F2015 to F2016 Revenue Requirements Rate Application (F15-F16 RRRA), March 7, 2014, Appendix C, at 40.
- ⁵ British Columbia Utilities Commission, Order No. G-48-14 in the matter of the Utilities Commission Act, R.S.B.C. 1996, Chapter 473 and British Columbia Hydro and Power Authority Application Regarding its Rates for F2014, F2015 and F2016, Expenditures on Demand Side Measures in F2014, F2015 and F2016 and Retail Access, March 24, 2014, at 6. Note, in 2016 the Province of British Columbia changed the rate regulation of BC Hydro such that starting in fiscal 2018 the company will no longer earn a set ROE as part of its revenue requirement, but rather will have rates designed to earn a specific distributable surplus (see, Project No. 3698869, British Columbia Utilities Commission British Columbia Hydro and Power Authority Fiscal 2017 to Fiscal 2019 Revenue Requirements Application Evidentiary Update, August 17, 2016, at 1-15.)

1
2 d) S&P does not rate OPG and the Province of Ontario the same. S&P assigns an A+ rating
3 to the Province of Ontario and a BBB+ rating to OPG (i.e., a three notch difference). In
4 addition, S&P states that its stand-alone credit profile for OPG is BBB-.

5
6 New Brunswick Power, Manitoba Hydro Electric System, Saskatchewan Power and BC
7 Hydro, in contrast, are either not separately rated from their Provinces (i.e., New
8 Brunswick Power) or receive a “flow-through” of the Province’s rating. The reason for this
9 is each of those companies’ debt obligations are either direct obligations of the Province
10 or are wholly guaranteed by the Province. The following are excerpts from DBRS
11 regarding each company’s credit rating (except New Brunswick Power, which is not
12 separately rated from the Province of New Brunswick):
13

- 14 • BC Hydro: “The ratings assigned to the Long- and Short-Term Obligations of BC
15 Hydro are a flow-through of the ratings of the Province of British Columbia (the
16 Province; rated AA (high) and R-1 (high) with Stable trends; see DBRS’s report
17 dated April 28, 2016). Pursuant to the B.C. Hydro and Power Authority Act, the
18 Long- and Short-Term Obligations of BC Hydro are either direct obligations of, or
19 are guaranteed by, the Province.” (DBRS Rating Report, British Columbia Hydro
20 and Power Authority, September 30, 2016, at 1.)
- 21 • Manitoba Hydro: “The ratings assigned to the Utility’s Long-Term Obligations and
22 Short-Term Obligations are a flow-through of the ratings of the Province of
23 Manitoba (the Province; rated A (high) and R-1 (middle) with Stable trends by
24 DBRS). Pursuant to The Manitoba Hydro Act, the Province unconditionally
25 guarantees almost all of Manitoba Hydro’s outstanding third-party debt.” (DBRS
26 Rating Report, The Manitoba Hydro-Electric Board, November 26, 2015, at 1.)
- 27 • Saskatchewan Power: “The ratings assigned to the Company’s Long- and Short-
28 Term Obligations are a flow-through of the ratings of the Province of
29 Saskatchewan (the Province; rated AA and R-1 (high) with Stable trends by
30 DBRS; see DBRS’s report on the Province dated September 12, 2016). Pursuant
31 to The Power Corporation Act (the Act), SaskPower does not issue debt directly in
32 the capital markets, but obtains funding from the Government of Saskatchewan
33 Ministry of Finance.” (DBRS Rating Report, Saskatchewan Power Corporation,
34 September 29, 2016, at 1.)
35

36 New Brunswick Power, Manitoba Hydro Electric System, Saskatchewan Power and BC
37 Hydro are not a better reference point for OPG’s capital structure because, as described
38 above and in part (c) to this response, rates are set for those utilities on a different basis
39 than they are set for OPG, and the risks for those utilities, as viewed by DBRS, are
40 indistinguishable from their provinces. That is clearly not the case with OPG. In fact,
41 those companies are rated by DBRS to be between three and six notches higher than
42 OPG (or five to eight notches when OPG’s stand-alone credit profile is considered). In
43 contrast, the publicly-traded proxy companies analyzed by Concentric were screened to
44 have risk characteristics similar to OPG, consistent with the fair return standard. In
45 addition, precedent in Ontario and other Canadian provinces for considering U.S. data for

1 cost of capital evaluations is set out in Appendix A to Exhibit C1-1-1, Attachment 1. For
2 those reasons, Concentric considers the proxy group to be a better reference point for
3 OPG's capital structure.
4

5 In addition, it is important to note that New Brunswick Power, Manitoba Hydro Electric
6 System and Saskatchewan Power are not authorized deemed equity ratios through the
7 ratemaking process, but rather the capital structures referenced in the footnotes in
8 response to VECC-9(c) represent target *actual* capital structures. OPG is significantly
9 underleveraged relative to its deemed capital structure. Reflecting the actual capital
10 structure in OPG's rates would result in an equity ratio of over 70%.⁶
11

12 e) Yes.

⁶ Calculated by setting the portion of rate base financed by deemed debt in Ex. C1-1-1 Tables 1-5 to the sum of short-term debt (line 1) and existing/planned long-term debt (line 2).

VECC Interrogatory #10

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Reference: C1/T1/S1/ Attachment 1 - Concentric Energy Report

- a) Please provide the Moody's or DBRS bond ratings for the respective companies as well as the S&P ratings already provided
- b) Please provide justification (page 360) for "*the investment community's view that generation, in general, is the riskiest business segment for a regulated utility.*" Would this assessment apply to Emera's main operating unit Nova Scotia Power?
- c) In terms of the DRP, is it Concentric's view that when a provincial or state owned utility undertakes a substantial capital programme at the behest of that owner, then the "stand alone" principle still applies and the owner is "rewarded" with a higher capital structure ratio due to its own actions? Please provide full theoretical justification or such a proposition if that it Concentric's view.
- d) Given that S&P "consolidates" OPG's bond ratings with that of the Province of Ontario please indicate what the capital expenditures ratio on page 37 is for the Province rather than its "subsidiary".
- e) At page 38 Concentric claims that the proxy group has "similar risk mitigating properties" as OPG. This is Concentric's judgment, please provide for each company their allowed and actual earned ROE for each year for the last 10 years to verify this judgment.
- f) With reference to the quotation from the OEB on page 40, please indicate what revenue % for each company in the proxy sample is derived from merchant generation, which the OEB regards as riskier.
- g) Please indicate whether Concentric agrees with the statement that, all else constant, nuclear assets are base load generation and difficult to shut down and then start up in response to demand shifts and that within generation base load is regarded as less riskier than assets used to meet peaking demand. If not why not?
- h) Given Concentric's judgment that OPG is riskier due to the DRP and its future nuclear assets would this judgement change if OPG was not owned by the Province of Ontario and required to meet provincial policy objectives and as a result operated say with gas cogeneration or coal plants, rather than nuclear plants?

Response

This response was prepared by Concentric Energy Advisors

- a) Please see Chart 1 below for the Moody's ratings for the respective companies. Of the proxy companies, DBRS only rates Fortis Inc., assigning it an A (low) rating as of October 7, 2016. The S&P ratings for each company can be found in Ex. C1-1-1, Attachment 1, Page 34.

Chart 1

	COMPANY	TICKER	MOODY'S¹
1	ALLETE, Inc.	ALE	A3
2	Ameren Corporation	AEE	Baa1
3	American Electric Power Company, Inc.	AEP	Baa1
4	Duke Energy Corporation	DUK	Baa1
5	Edison International	EIX	A3
6	El Paso Electric Company	EE	Baa1
7	Emera Inc.	EMA	Baa3
8	Entergy Corporation	ETR	Baa3
9	FirstEnergy Corporation	FE	Baa3
10	Fortis Inc.	FTS	Baa3
11	Great Plains Energy Inc.	GXP	Baa2
12	IDACORP, Inc.	IDA	Baa1
13	NextEra Energy, Inc.	NEE	Baa1
14	PG&E Corporation	PCG	Baa1
15	Pinnacle West Capital Corporation	PNW	A3
16	PNM Resources, Inc.	PNM	Baa3
17	Portland General Electric Company	POR	A3

¹ SNL Financial Data as of October 6, 2016.

	COMPANY	TICKER	MOODY'S ¹
18	Southern Company	SO	Baa2
19	Westar Energy, Inc.	WR	Baa1
20	Xcel Energy Inc.	XEL	A3

b) The correct reference for this quote is Ex. C1-1-1, Attachment 1, Page 32.

Moody's states in its December 23, 2013 Rating Methodology: Regulated Electric and Gas Utilities report, "[w]e view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays." This assessment would apply, in part, to Emera's main operating unit Nova Scotia Power, recognizing that Nova Scotia Power is an integrated utility with generation, transmission and distribution assets, and is not exclusively a generation company.

c) Concentric does not agree with the premise of the question. As discussed in response to Ex. L-3.1-20 VECC-9, part (a), the stand-alone principle is a "long-established regulatory principle." The stand-alone principle provides that the rates set for a utility reflect the specific operations and risk profile of the utility, not its parent or affiliate companies. As such, the stand-alone principle is not a vehicle through which an owner is "rewarded" or "punished." Rather, it is a ratemaking basis that ensures rates reflect the full cost of service of a utility enterprise, not the costs, risks or benefits of the utility's parent or affiliates.

d) S&P rates OPG and the Province of Ontario separately. As discussed in response to Ex. L-3.1-20 VECC-9, part (a), Concentric's assessment of OPG's risk profile was performed on a stand-alone basis. As such, Concentric did not obtain data or evaluate the Province of Ontario's capital expenditures ratio.

e) The partial quote in the interrogatory mischaracterizes the referenced passage from Concentric's report. Specifically, the referenced passage states, "...the proxy companies likewise have many accounts with similar risk-mitigating properties..." The excerpted passage is from a section of the report that discusses cost recovery risk for the proxy companies. Concentric's conclusion was not based on, or verified with, the requested data.

f) Please refer to Concentric's response to Ex. L-3.1-1 Staff-15 for non-rate regulated generation capacity for each company. Concentric is not aware of a source that consistently reports proxy company revenues from merchant generation in a readily available format.

- 1 g) No, Concentric does not agree with the statement in the interrogatory. While Concentric
2 agrees that, all else being equal, nuclear assets are generally considered baseload
3 generation, Concentric does not agree that baseload generation (and particularly nuclear
4 baseload) is considered less risky than peaking generation. The reasons for this include:
5 (1) higher construction risk (as discussed in Ex. C1-1-1, Attachment 1, Page 20); (2)
6 higher levels of fixed costs that must be recovered through continuous generation (*i.e.*,
7 increased exposure to the risk of long-term outages and technology risk); and (3) more
8 exposure to market price risk for power plants that sell their power into wholesale
9 markets.
10
- 11 h) The question requires speculation both about an alternative ownership structure and
12 technology mix for OPG and did not serve as a basis for Concentric's risk assessment.
13 OPG's riskiness would not change based on its ownership (see discussion of the stand-
14 alone principle in Ex. L-3.1-20 VECC-9, part (a) and Ex. L-3.1-20 VECC-10, parts (c) and
15 (d)). OPG's risk profile could change if had a different mix of generation assets,
16 particularly given the risks that are specific to nuclear plants in general and nuclear
17 construction projects more specifically.

VECC Interrogatory #11

Issue Number: 3.1

Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:

Reference: C1/T1/S1/Attachment 1 Concentric Energy Report

Preamble: In its Decision EB-2011-0354 the Board stated (page 7):

"Regarding the risk of future events, the Board agrees with CCC that the relevant future risks are those that are likely to affect Enbridge in the near term. Any risks that may materialize over the longer term can be taken into account in subsequent proceedings. In considering the risk of future events, the Board will take into account the fact that, generally, the more distant the potential event, the more speculative is any conclusion on the likelihood that the risk will materialize."

- a) In Concentric's view has the additional risk of nuclear facilities "materialized" given that at the earliest it is at the tail end of the test period and may in all probability slip beyond the test period?
- b) Is it Concentric's view that current ratepayers should pay the "risk" cost of DRP given that the facilities are not currently part of their cost of service? Please explain in detail whether this meets inter-generational equity concerns.

Response

This response was prepared by Concentric Energy Advisors

- a) & b) Yes, the additional risk of nuclear facilities has materialized for OPG and is ongoing in the near term. In particular, the DRP was initiated in October 2016, and the Pickering extension will also take place in the next few years. The DRP and Pickering extension require significant capital investment by OPG, and both projects create incremental risk for OPG.

It is Concentric's view that OPG's rates should reflect a fair return, including the capital structure. As discussed in Concentric's Common Equity Ratio Report (Ex. C1-1-1 Attachment 1, pages 13 and 14) the cost of capital (including the capital structure) is a forward-looking concept from the perspective of investors. While the DRP is a significant driver of risk, it is not the only risk driver facing OPG's regulated operations. With respect to large projects such as the DRP, the underlying risk exists before such projects enter into productive service. The capital structure reflecting that risk should be reflected in

1 rates before a project enters into productive service so that capital for the project can be
2 raised over the 2017 to 2021 period and appropriately compensated. In other words, the
3 cost of capital today reflects investors' views of future performance and risks. That
4 concept is not at odds with inter-generational equity principles, which generally hold that
5 costs incurred in providing service in one period (for one generation of ratepayers) should
6 not be paid in a different period by a different generation of ratepayers.

7
8 Investors and credit rating agencies are aware of OPG's elevated capital spending
9 program and shifting rate base between 2017 and 2021 and beyond. In order to ensure
10 investors and rating agencies that there is regulatory support for cost recovery and credit
11 quality, OPG's authorized cost of capital should reflect the increased risk profile of its
12 elevated capital spending program and its shifting rate base to a higher percentage of
13 nuclear assets relative to hydroelectric assets.

14
15 OPG's substantial capital investments over the next five years will place pressure on
16 OPG's cash flows and credit metrics during this period. In particular, OPG forecasts total
17 capital expenditures of approximately \$5.25 billion on the DRP from 2017-2021 (Ex. D2-
18 2-10, Table 1). DBRS has commented specifically on the risk associated with the DRP
19 as follows:

20
21 *DBRS believes that given the complexity and scale of the Darlington*
22 *Refurbishment, there is significant execution risk as well as the*
23 *potential for cost overruns. The high capital expenditures (capex)*
24 *required, albeit spread over a ten-year period, in addition to ongoing*
25 *maintenance capex (total capex forecast of approximately \$2 billion in*
26 *2016), are expected to pressure OPG's key credit metrics.¹*

27
28 DBRS also notes that OPG is expected to generate a free cash flow deficit in 2016 due
29 to the large capital expenditure program.²

30
31 Credit rating agencies have also commented more generally about the credit risk
32 associated with large capital spending programs. For example, DBRS writes:

33
34 *For utilities undergoing significant multi-year capital expansion*
35 *programs, capital spending may be considered a primary rating factor.*
36 *This would be particularly relevant for companies with significant*
37 *nuclear generation development.³*

38
39 Please see the response to Ex. L-3.1-1 Staff-010(b) for additional rating agency
40 comments regarding the risk associated with major capital spending programs.

¹ DBRS, Rating Report: Ontario Power Generation Inc., April 25, 2016, at 1.

² *Ibid.*

³ DBRS, Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry, October 2015, at 7.

Board Staff Interrogatory #022

Issue Number: 3.2

Issue: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Reference:

Ref: Exh C1-1-2

In Exh C1-1-2, OPG documents its cost of debt, and notes that it is adhering to the approach approved in the previous payment amount applications.

With respect to new or forecasted debt during the test period, OPG uses estimates from Global Insights for the Forecast 10-year Long [sic] Canada Bond Rate, and adds on the observed corporate spread. OPG notes that the spread at the end of December 2015 was 161 basis points. OPG provides the forecasted 10-year Canada Bond Rate by quarter for 2016 to 2021 in Table 1, and the forecasted long term debt rate in Table 2.

- a) Please provide a copy of the Global Insights forecast for January 2016 upon which OPG is relying for its forecasts shown in Tables 1 and 2.
- b) In Table 1, the forecasted rate is 3.32% for 2019 Q1 and for every quarter thereafter. Please indicate whether the Global Insights forecast is 3.32% for each quarter from 2016 Q1 to 2021 Q4, or whether OPG has just extrapolated the rate for 2016 Q1 to be the same for all subsequent quarters during the test period.
- c) If OPG has more recent forecasts from Global Insights or from any other economic forecaster for 10-year Government of Canada Bond Yield rate, please file these updated forecasts.

Response

- a) Please see the top section of Table 1 in Attachment 1 for the Global Insights forecast for January 2016 upon which OPG is relying for its forecasts shown in Ex. C1-1-2 Charts 1 and 2.
- b) The information in Table 1 represents the Global Insight forecast for each quarter without any extrapolation by OPG, as shown in Table 1 of Attachment 1.
- c) OPG has a Global Insights forecast for 10-year Government of Canada Bond Yield rate, released September 9, 2016. It is provided in the bottom section of Table 1, Attachment 1.

Table 1
Global Insight (GI): Selected Economic Indicators

Used in EB-2016-0152 Prefiled Evidence

	16Q1	16Q2	16Q3	16Q4	17Q1	17Q2	17Q3	17Q4	18Q1	18Q2	18Q3	18Q4
GOC Ten-Year Bond Rate (%)	1.98	2.13	2.20	2.26	2.32	2.36	2.39	2.48	2.62	2.79	3.07	3.28
	19Q1	19Q2	19Q3	19Q4	20Q1	20Q2	20Q3	20Q4	21Q1	21Q2	21Q3	21Q4
GOC Ten-Year Bond Rate (%)	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32

Update:

Release date Sept 9 2016

	16Q1	16Q2	16Q3	16Q4	17Q1	17Q2	17Q3	17Q4	18Q1	18Q2	18Q3	18Q4
GOC Ten-Year Bond Rate (%)	1.20	1.33	1.10	1.39	1.69	1.84	2.04	2.17	2.34	2.43	2.62	2.76
	19Q1	19Q2	19Q3	19Q4	20Q1	20Q2	20Q3	20Q4	21Q1	21Q2	21Q3	21Q4
GOC Ten-Year Bond Rate (%)	2.90	3.11	3.37	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44

Source: Global Insight - Canada - Spreadsheet tables - Quarterly Forecast Tables

Board Staff Interrogatory #23

Issue Number: 3.2

Issue: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Reference:

Ref: Exh C1-1-2

Ref: Consensus Forecasts (January 2009 to date)

Ref: Bank of Canada website – month-end 10 Government of Canada Bond Yields Ref: O.Reg. 53/05

OPG has relied on the methodology accepted by the OEB in its prior payments applications with respect to the methodology for forecasting the long-term debt rate for forecasted new long-term debt that it expects to incur during the test period.

OPG's methodology is similar to that adopted by the OEB for estimating the deemed long-term debt rate that applies or acts as a ceiling on long-term debt costs, in accordance with the OEB's current cost of capital policy as documented in the Report of the Board on the Cost of Capital for Ontario's regulated Utilities (EB-2009-0084), December 11, 2009. However, the methodology differs in two major respects:

- OPG forecasts the rate for new debt "based on the prevailing benchmark Government of Canada bond for the corresponding term of the debt, as published by a verifiable market monitoring service on the day prior to the date funds are advanced, plus a credit margin determined five business days before the date funds are advanced. The credit margin is determined based on a sample of quotes for OPG's credit margin as provided by a selected group of Canadian banks."⁴
- Since OPG's test period has been for two years in all previous payments applications, and the forecast period for the application is longer than the one-year horizon in *Consensus Forecasts* as used by the OEB, OPG uses longer-term estimates of the 10-year Government of Canada bond yield from IHS Global Insights to cover the 2-year test period.

OPG is not proposing any changes to its previously accepted methodology. However, with the longer term period of the current application from 2017-21, in addition to the bridge year of 2016, it is forecasting the cost of new or replacement debt over a forecast period of 6 years, at least double that from previous applications.

OEB staff undertook an analysis to compare the forecasting error of the three-month ahead and 12-month ahead forecasts of the 10-year Government of Canada bond yield as published by *Consensus Forecasts*, and which the OEB relies on for its long-term debt rate

and ROE estimates. This analysis calculates the variance between the month- end 10-year Government of Canada bond yield as published on the Bank of Canada website against the 3-month and 12-month ahead forecasts for the 10-Year Government of Canada bond yield published earlier in Consensus Forecasts for that same month-end. OEB staff notes that IHS Global Insights is one of the economic forecasters surveyed by *Consensus Forecasts*, and so has done the analysis based on both the overall Consensus Forecast and on the IHS Global Insights estimates provided to and published by *Consensus Forecasts*. The analysis was done for all months from January 2010 to date, covering the period of the OEB's current cost of capital methodology and also since the recovery from the 2008-2009 global economic downturn and the current period of low interest rates.

The analysis is documented in a separate Microsoft Excel spreadsheet.

The results are summarized in the following table:

[OEB Attachment](#)

⁴ Exh C1-1-2 page 3

**Variance from actual 10-year Government of Canada bond yield month
end January 2010 - July 2016**

	<i>Consensus Forecasts</i>		IHS Global Insights estimate from <i>Consensus Forecasts</i>	
	Difference from actual of 3-month forecast	Difference from actual of 12-month ahead forecast	Difference from actual of 3-month forecast	Difference from actual of 12-month ahead forecast
Mean	0.30	0.90	0.44	0.94
Max	1.21	2.21	1.48	2.1
Min	-0.73	-0.63	-0.91	-0.66

All numbers are percentages

The analysis demonstrates the forecasting errors. First, the forecasting error is generally higher for the 12-month ahead forecast than for the three-month ahead forecast, and the bias is much higher for the longer-term forecast. It would be expected that even longer forecasts – 2-, 3- or 5-years would show even larger forecasting errors.

These results are not surprising in current economic conditions, where persistent low interest rates make the likelihood and magnitude of under-forecasting less than for over- forecasting. Nor does this imply that the forecasts are not credible or should not be used, but that caution is advised. Longer-term forecasts are much more likely to be in error and to be significantly

1 over-forecasted under current conditions.
2

3 OPG has proposed that its weighted average cost of long-term debt, applicable to \$4,000M in
4 new and replacement debt over the period 2016-2021 be approved in this proceeding. OEB
5 staff also notes that the weighted average long-term debt rate approved is also used to
6 calculate the carrying costs on the rate smoothing deferral account set out in O.Reg. 53/05.
7

8 a) Has OPG conducted any similar analysis of the forecasting error of the IHS Global
9 Insights forecast data that it subscribes to? If so, please provide copies of any such
10 analyses.
11

12 b) Can OPG undertake to provide an analysis similar to OEB staff's analysis based on IHS
13 Global Insights. If not, please explain.
14

15 c) The analysis indicates that there is high risk of forecasting error in the long-term debt
16 rate, and that this increases the farther out the forecasting is. As shown in Charts 1 and
17 2 of Exh C1-1-2, OPG is forecasting 6-years out. OPG has also proposed a new
18 Nuclear ROE Variance Account to track the impact on the nuclear revenue requirement
19 of the annual update of the ROE. How does OPG propose to mitigate the risk that the
20 long term debt rate and/or that OPG's new or replacement long term debt does not
21 occur as forecasted?, Would it not also be reasonable that an account be used to track
22 the variance of the nuclear revenue requirement in each year from what is approved in
23 this application and what would be the revenue requirement based on actual debt and
24 the actual weighted average cost of long term debt?
25

26 d) A variation on c) would be for OPG, in its annual payment application which it proposes
27 to file to update the hydroelectric payments in accordance with the approved
28 hydroelectric Price Cap plan, to also file updated forecasted long-term debt rates based
29 on shorter-term forecasts (3-months and one-year ahead) of its expected debt cost. The
30 forecasting error would be much smaller. The approach would be analogous to what
31 Enbridge Gas Distribution Inc. does with its annual rate applications under its current
32 multi-year rate plan.
33

34 Please provide OPG's views as to whether the account described in c) or that in d) is
35 preferable. Please explain.
36
37

38 Response 39

40 Before responding to the above question, OPG wishes to clarify how the rate for new debt
41 issuances is forecasted. As stated in EX. C1-1-2 on page 4, the cost of planned new and
42 refinanced corporate debt and project-related debt for 2016 to 2021 is based on a forecast of
43 the 10-year Long Canada Bond published in January 2016 by Global Insight. OPG's credit
44 spread of 161 basis points (OPG's credit spread at the end of 2015) is added to the bond
45 rates to determine the forecast for OPG's OEFC planned debt in 2016 to 2021.
46

The preamble to this question erroneously stated that OPG forecasts the rate for new debt “based on the prevailing benchmark Government of Canada bond for the corresponding term of the debt, as published by a verifiable market monitoring service on the day prior to the date funds are advanced, plus a credit margin determined five business days before the date funds are advanced. The credit margin is determined based on a sample of quotes for OPG’s credit margin as provided by a selected group of Canadian banks.” This quote from OPG’s evidence at Ex. C1-1-2 page 3 is describing how a rate is assigned once the debt is issued.

- a) No, OPG has not conducted a similar analysis of the forecast data provided by IHS Global Insights.
- b) OPG has prepared an analysis of IHS Global Insight forecasts of Government of Canada 10-year bond yields for 2-years ahead, 3-years ahead and 5-years ahead compared to the actual yield on Government of Canada 10-year bonds. The results of this analysis are summarized in Table 1 below:

Table 1: IHS Global Insight Forecasts Variance Analysis

	Difference from actual of 2-years ahead forecast - IHS Global Insight	Difference from actual of 3-years ahead forecast - IHS Global Insight	Difference from actual of 5-years ahead forecast - IHS Global Insight
Mean	1.76	2.52	3.46
Max	3.76	3.80	5.06
Min	0.27	1.53	1.28

- c) Since the Nuclear component of new debt issuances makes up relatively small component of OPG’s rate base, the actual cost of debt has a relative small impact on OPG’s nuclear revenue requirement. As a result, OPG does not believe that the long-term debt forecast poses a significant risk that requires mitigation.

Table 1 below shows the percentage of total Rate Base attributed to the Nuclear business as shown in C1-1-1 Chart 1:

Table 1: Breakdown of Rate Base

Rate Base	2017	2018	2019	2020	2021
Hydro (\$B)	7.5	7.5	7.5	7.6	7.7
Nuclear (\$B)	3.3	3.5	3.5	7.5	8.0
Total (\$B)	10.8	11.0	10.9	15.1	15.6
Nuclear Portion of Total Rate Base	31%	32%	32%	50%	51%

Table 2 below shows the small component of rate base attributed to the cumulative new debt issuances over the 2017-2021 term.

Table 2: Impact of New Debt Issuances Attributed to Nuclear

	2017	2018	2019	2020	2021
Cumulative Total New Debt Issuances ¹ (\$B)	0.5	1.4	1.9	2.3	2.5
Total Rate Base (\$B)	10.8	11.0	10.9	15.1	15.6
Component of Rate Base Attributed to New Debt Issuances	5%	12%	17%	15%	16%
Nuclear Portion of Total Rate Base	31%	32%	32%	50%	51%
Nuclear Component of Rate Base Attributed to New Debt Issuances	2%	4%	6%	8%	8%

In contrast to the small component of rate base that can be attributed to the 2017-2021 new debt issuances, the Nuclear component of rate base attributed to equity ranges from 15% to 25% over 2017-2021. This larger makeup of the overall rate base is what makes it appropriate to track the changes in ROE in a variance account.

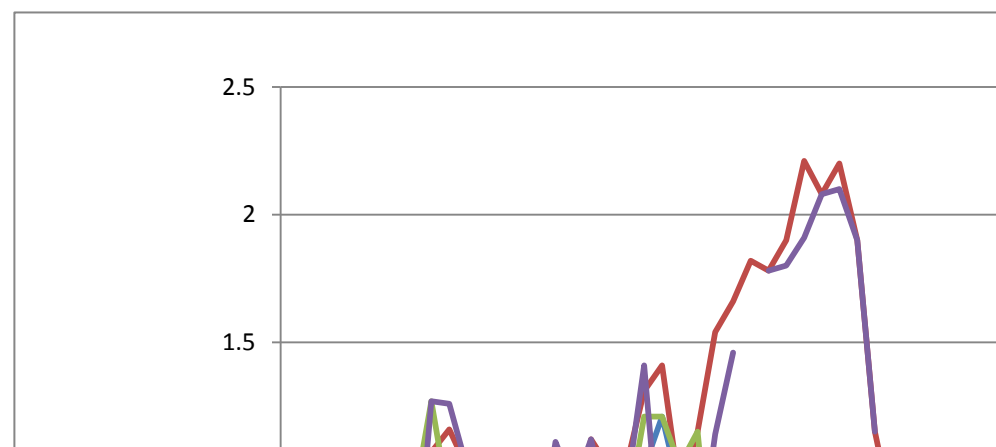
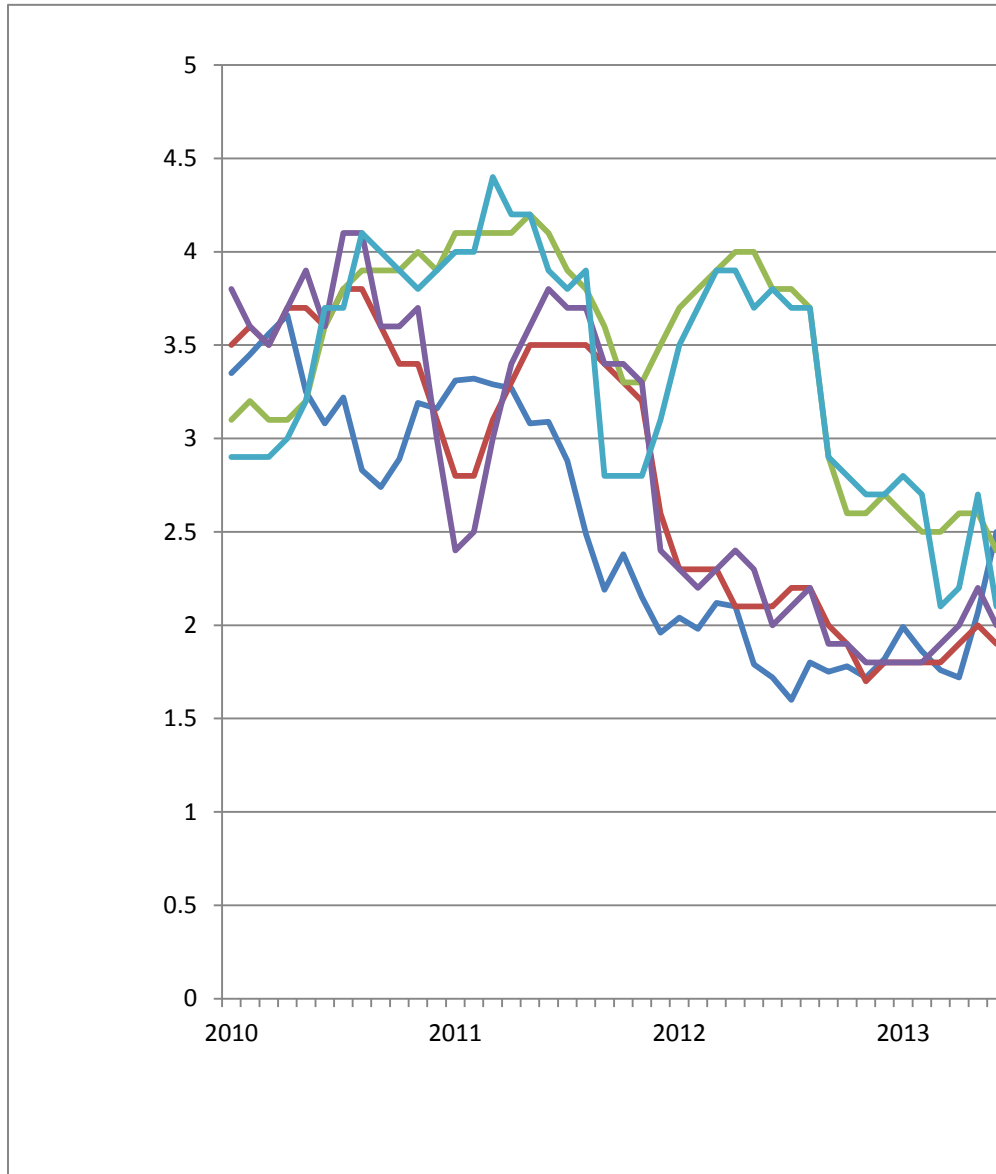
- d) As discussed in 3.1-Staff-20, OPG agrees that the cost of capital that is implicitly reflected in the hydroelectric payment “rates” will change every year in accordance with the price cap adjustment. As such OPG understands that the option discussed in part d) would apply to Nuclear only.

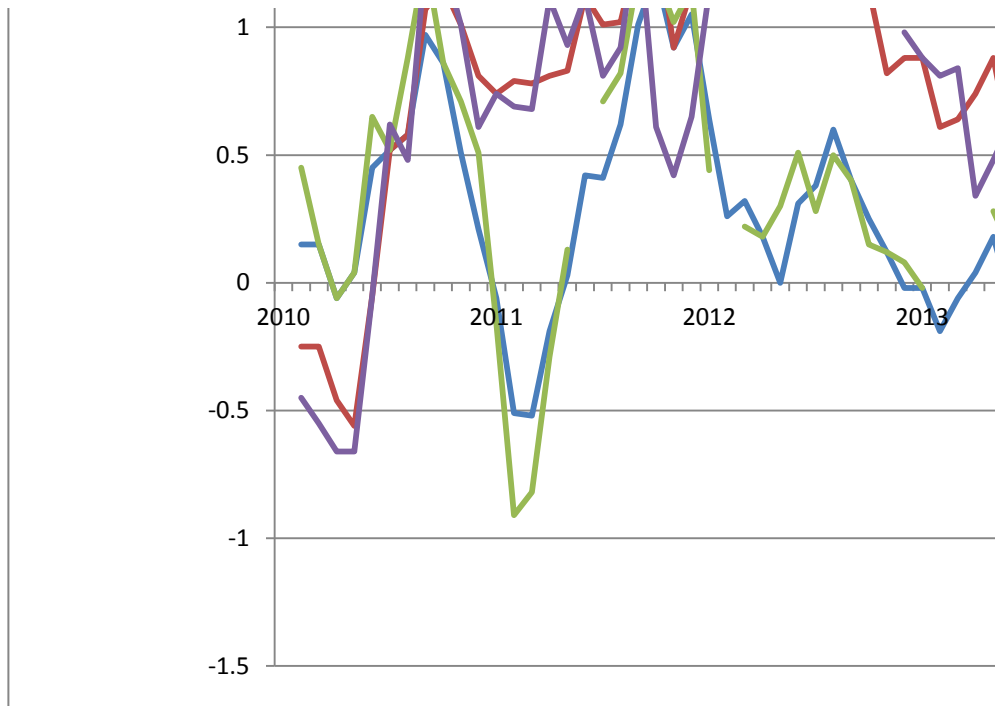
OPG understands that 4GIRM (and price-cap index-based regulation in general) is premised on the regulatory efficiency that results from the mechanistic nature and the narrow scope of annual adjustment proceedings. To the extent that the nature and scope of those proceedings are expanded to include the review of proposals to change OPG’s cost components, those proceedings are made more complex, regulatory efficiency is reduced, and related costs increase.

¹ New issues are weighted in the year issued based on issue date, and allocated to the regulated business based on the allocation percentage identified at Ex. C1-1-2 Table 1, row 13

Month-end		Consensus	
		3-month ahead forecast	
		10-year Government of Canada Bond Yield	
		Estimate (Consensus	
		Forecasts - 3 month	
		ahead)	
		Survey Date	
10-year Government of Canada Bond Yield (%)			
2010 January	3.35	3.5	12-Oct-09
February	3.45	3.6	9-Nov-09
March	3.56	3.5	7-Dec-09
April	3.66	3.7	11-Jan-10
May	3.25	3.7	8-Feb-10
June	3.08	3.6	8-Mar-10
July	3.22	3.8	12-Apr-10
August	2.83	3.8	10-May-10
September	2.74	3.6	14-Jun-10
October	2.89	3.4	12-Jul-10
November	3.19	3.4	9-Aug-10
December	3.16	3.1	13-Sep-10
2011 January	3.31	2.8	11-Oct-10
February	3.32	2.8	8-Nov-10
March	3.29	3.1	6-Dec-10
April	3.27	3.3	10-Jan-11
May	3.08	3.5	14-Feb-11
June	3.09	3.5	14-Mar-11
July	2.88	3.5	4-Apr-11
August	2.49	3.5	9-May-11
September	2.19	3.4	13-Jun-11
October	2.38	3.3	11-Jul-11
November	2.15	3.2	8-Aug-11
December	1.96	2.6	12-Sep-11
2012 January	2.04	2.3	10-Oct-11
February	1.98	2.3	14-Nov-11
March	2.12	2.3	12-Dec-11
April	2.1	2.1	9-Jan-12
May	1.79	2.1	13-Feb-12
June	1.72	2.1	12-Mar-12
July	1.6	2.2	10-Apr-12
August	1.8	2.2	14-May-12
September	1.75	2.0	11-Jun-12
October	1.78	1.9	9-Jul-12
November	1.72	1.7	13-Aug-12
December	1.82	1.8	10-Sep-12
2013 January	1.99	1.8	8-Oct-12
February	1.86	1.8	12-Nov-12

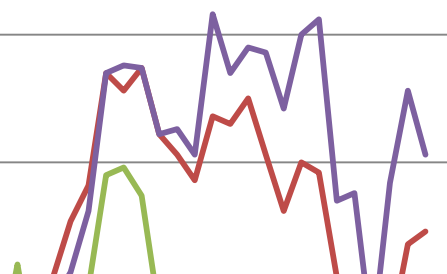
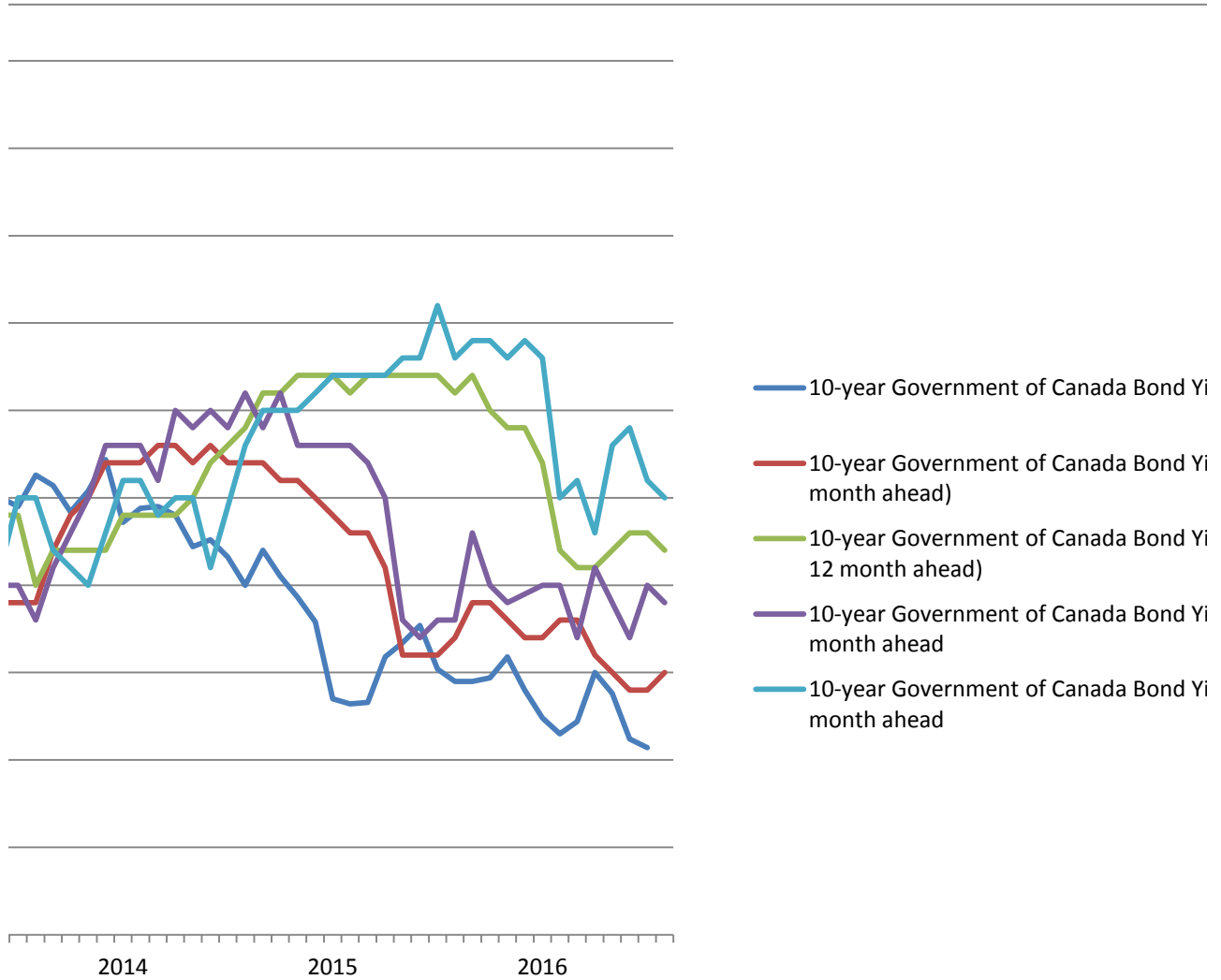
	March	1.76	1.8	10-Dec-12
	April	1.72	1.9	14-Jan-13
	May	2.07	2	11-Feb-13
	June	2.5	1.9	11-Mar-13
	July	2.45	1.9	8-Apr-13
	August	2.63	1.9	13-May-13
	September	2.57	2.2	10-Jun-13
	October	2.42	2.4	8-Jul-13
	November	2.54	2.5	12-Aug-13
	December	2.72	2.7	9-Sep-13
2014	January	2.36	2.7	14-Oct-13
	February	2.44	2.7	11-Nov-13
	March	2.45	2.8	9-Dec-13
	April	2.4	2.8	13-Jan-14
	May	2.22	2.7	10-Feb-14
	June	2.26	2.8	10-Mar-14
	July	2.16	2.7	14-Apr-14
	August	2	2.7	12-May-14
	September	2.2	2.7	9-Jun-14
	October	2.05	2.6	14-Jul-14
	November	1.93	2.6	11-Aug-14
	December	1.79	2.5	8-Sep-14
2015	January	1.35	2.4	13-Oct-14
	February	1.32	2.3	10-Nov-14
	March	1.33	2.3	8-Dec-14
	April	1.59	2.1	12-Jan-15
	May	1.67	1.6	9-Feb-15
	June	1.77	1.6	9-Mar-15
	July	1.52	1.6	13-Apr-15
	August	1.45	1.7	11-May-15
	September	1.45	1.9	8-Jun-15
	October	1.47	1.9	13-Jul-15
	November	1.59	1.8	10-Aug-15
	December	1.4	1.7	7-Sep-15
2016	January	1.24	1.7	12-Oct-15
	February	1.15	1.8	9-Nov-15
	March	1.22	1.8	7-Dec-15
	April	1.5	1.6	11-Jan-16
	May	1.38	1.5	8-Feb-16
	June	1.12	1.4	7-Mar-16
	July	1.07	1.4	11-Apr-16
	August		1.5	9-May-16

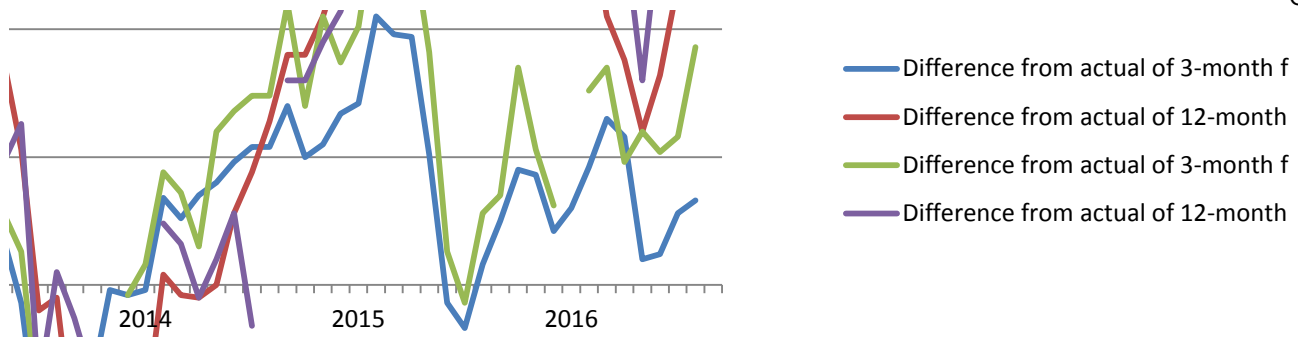




Forecasts			Variance Analysis		IHS Economics / Global	
12-month-ahead forecast			Difference from actual of 3-month forecast (Consensus Forecast)	Difference from actual of 12-month ahead forecast (Consensus Forecast)	3-month ahead forecast	
10-year Government of Canada Bond Yield Estimate (Consensus Forecasts - 12 month ahead)					10-year Government of Canada Bond Yield Estimate - Global Insight IHS - 3 month ahead	Survey Date
	3.1	12-Jan-09	0.15	-0.25	3.8	12-Oct-09
	3.2	9-Feb-09	0.15	-0.25	3.6	9-Nov-09
	3.1	9-Mar-09	-0.06	-0.46	3.5	7-Dec-09
	3.1	14-Apr-09	0.04	-0.56	3.7	11-Jan-10
	3.2	11-May-09	0.45	-0.05	3.9	8-Feb-10
	3.6	8-Jun-09	0.52	0.52	3.6	8-Mar-10
	3.8	13-Jul-09	0.58	0.58	4.1	12-Apr-10
	3.9	10-Aug-09	0.97	1.07	4.1	10-May-10
	3.9	14-Sep-09	0.86	1.16	3.6	14-Jun-10
	3.9	12-Oct-09	0.51	1.01	3.6	12-Jul-10
	4.0	9-Nov-09	0.21	0.81	3.7	9-Aug-10
	3.9	7-Dec-09	-0.06	0.74	3.0	13-Sep-10
	4.1	11-Jan-10	-0.51	0.79	2.4	11-Oct-10
	4.1	8-Feb-10	-0.52	0.78	2.5	8-Nov-10
	4.1	8-Mar-10	-0.19	0.81	3.0	6-Dec-10
	4.1	12-Apr-10	0.03	0.83	3.4	10-Jan-11
	4.2	10-May-10	0.42	1.12	#N/A	14-Feb-11
	4.1	14-Jun-10	0.41	1.01	3.8	14-Mar-11
	3.9	12-Jul-10	0.62	1.02	3.7	4-Apr-11
	3.8	9-Aug-10	1.01	1.31	3.7	9-May-11
	3.6	13-Sep-10	1.21	1.41	3.4	13-Jun-11
	3.3	11-Oct-10	0.92	0.92	3.4	11-Jul-11
	3.3	8-Nov-10	1.05	1.15	3.3	8-Aug-11
	3.5	6-Dec-10	0.64	1.54	2.4	12-Sep-11
	3.7	10-Jan-11	0.26	1.66	#N/A	10-Oct-11
	3.8	14-Feb-11	0.32	1.82	2.2	14-Nov-11
	3.9	14-Mar-11	0.18	1.78	2.3	12-Dec-11
	4.0	4-Apr-11	0	1.9	2.4	9-Jan-12
	4.0	9-May-11	0.31	2.21	2.3	13-Feb-12
	3.8	13-Jun-11	0.38	2.08	2.0	12-Mar-12
	3.8	11-Jul-11	0.6	2.2	2.1	10-Apr-12
	3.7	8-Aug-11	0.4	1.9	2.2	14-May-12
	2.9	12-Sep-11	0.25	1.15	1.9	11-Jun-12
	2.6	10-Oct-11	0.12	0.82	1.9	9-Jul-12
	2.6	14-Nov-11	-0.02	0.88	1.8	13-Aug-12
	2.7	12-Dec-11	-0.02	0.88	1.8	10-Sep-12
	2.6	9-Jan-12	-0.19	0.61	#N/A	8-Oct-12
	2.5	13-Feb-12	-0.06	0.64	1.8	12-Nov-12

2.5	12-Mar-12	0.04	0.74	#N/A	10-Dec-12
2.6	10-Apr-12	0.18	0.88	2.0	14-Jan-13
2.6	14-May-12	-0.07	0.53	2.2	11-Feb-13
2.4	11-Jun-12	-0.6	-0.1	2.0	11-Mar-13
2.4	9-Jul-12	-0.55	-0.05	2.0	8-Apr-13
2.0	13-Aug-12	-0.73	-0.63	1.8	13-May-13
2.2	10-Sep-12	-0.37	-0.37	2.1	10-Jun-13
2.2	8-Oct-12	-0.02	-0.22	#N/A	8-Jul-13
2.2	12-Nov-12	-0.04	-0.34	2.5	12-Aug-13
2.2	10-Dec-12	-0.02	-0.52	2.8	9-Sep-13
2.4	14-Jan-13	0.34	0.04	2.8	14-Oct-13
2.4	11-Feb-13	0.26	-0.04	2.8	11-Nov-13
2.4	11-Mar-13	0.35	-0.05	2.6	9-Dec-13
2.4	8-Apr-13	0.4	0	3.0	13-Jan-14
2.5	13-May-13	0.48	0.28	2.9	10-Feb-14
2.7	10-Jun-13	0.54	0.44	3.0	10-Mar-14
2.8	8-Jul-13	0.54	0.64	2.9	14-Apr-14
2.9	12-Aug-13	0.7	0.9	3.1	12-May-14
3.1	9-Sep-13	0.5	0.9	2.9	9-Jun-14
3.1	14-Oct-13	0.55	1.05	3.1	14-Jul-14
3.2	11-Nov-13	0.67	1.27	2.8	11-Aug-14
3.2	9-Dec-13	0.71	1.41	2.8	8-Sep-14
3.2	13-Jan-14	1.05	1.85	2.8	13-Oct-14
3.1	10-Feb-14	0.98	1.78	2.8	10-Nov-14
3.2	10-Mar-14	0.97	1.87	2.7	8-Dec-14
3.2	14-Apr-14	0.51	1.61	2.5	12-Jan-15
3.2	12-May-14	-0.07	1.53	1.8	9-Feb-15
3.2	9-Jun-14	-0.17	1.43	1.7	9-Mar-15
3.2	14-Jul-14	0.08	1.68	1.8	13-Apr-15
3.1	11-Aug-14	0.25	1.65	1.8	11-May-15
3.2	8-Sep-14	0.45	1.75	2.3	8-Jun-15
3	13-Oct-14	0.43	1.53	2.0	13-Jul-15
2.9	10-Nov-14	0.21	1.31	1.9	10-Aug-15
2.9	8-Dec-14	0.3	1.5	#N/A	7-Sep-15
2.7	12-Jan-15	0.46	1.46	2.0	12-Oct-15
2.2	9-Feb-15	0.65	1.05	2.0	9-Nov-15
2.1	9-Mar-15	0.58	0.88	1.7	7-Dec-15
2.1	13-Apr-15	0.1	0.6	2.1	11-Jan-16
2.2	11-May-15	0.12	0.82	1.9	8-Feb-16
2.3	8-Jun-15	0.28	1.18	1.7	7-Mar-16
2.3	13-Jul-15	0.33	1.23	2.0	11-Apr-16
2.2	10-Aug-15			1.9	9-May-16
Mean		0.30	0.90		
Max		1.21	2.21		
Min		-0.73	-0.63		





I Insights (part of C.F.)		Variance Analysis	
12-month-ahead forecast		Difference	Difference from
10-year		from actual of	actual of 12-
Government of		3-month	month ahead
Canada Bond		forecast - IHS	forecast - IHS
Yield Estimate -		Global Insight	Global Insight
Global Insight IHS -			
12 month ahead	Survey Date		
2.9	12-Jan-09	0.45	-0.45
2.9	9-Feb-09	0.15	-0.55
2.9	9-Mar-09	-0.06	-0.66
3.0	14-Apr-09	0.04	-0.66
3.2	11-May-09	0.65	-0.05
3.7	8-Jun-09	0.52	0.62
3.7	13-Jul-09	0.88	0.48
4.1	10-Aug-09	1.27	1.27
4.0	14-Sep-09	0.86	1.26
3.9	12-Oct-09	0.71	1.01
3.8	9-Nov-09	0.51	0.61
3.9	7-Dec-09	-0.16	0.74
4.0	11-Jan-10	-0.91	0.69
4.0	8-Feb-10	-0.82	0.68
4.4	8-Mar-10	-0.29	1.11
4.2	12-Apr-10	0.13	0.93
4.2	10-May-10		1.12
3.9	14-Jun-10	0.71	0.81
3.8	12-Jul-10	0.82	0.92
3.9	9-Aug-10	1.21	1.41
2.8	13-Sep-10	1.21	0.61
2.8	11-Oct-10	1.02	0.42
2.8	8-Nov-10	1.15	0.65
3.1	6-Dec-10	0.44	1.14
3.5	10-Jan-11		1.46
#N/A	14-Feb-11	0.22	
3.9	14-Mar-11	0.18	1.78
3.9	4-Apr-11	0.3	1.8
3.7	9-May-11	0.51	1.91
3.8	13-Jun-11	0.28	2.08
3.7	11-Jul-11	0.5	2.1
3.7	8-Aug-11	0.4	1.9
2.9	12-Sep-11	0.15	1.15
#N/A	10-Oct-11	0.12	
2.7	14-Nov-11	0.08	0.98
2.7	12-Dec-11	-0.02	0.88
2.8	9-Jan-12		0.81
2.7	13-Feb-12	-0.06	0.84

	2.1	12-Mar-12		0.34
	2.2	10-Apr-12	0.28	0.48
	2.7	14-May-12	0.13	0.63
	2.1	11-Jun-12	-0.5	-0.4
	2.5	9-Jul-12	-0.45	0.05
	2.5	13-Aug-12	-0.83	-0.13
	2.2	10-Sep-12	-0.47	-0.37
#N/A		8-Oct-12		
	2.0	12-Nov-12	-0.04	-0.54
#N/A		10-Dec-12	0.08	
	2.6	14-Jan-13	0.44	0.24
	2.6	11-Feb-13	0.36	0.16
	2.4	11-Mar-13	0.15	-0.05
	2.5	8-Apr-13	0.6	0.1
	2.5	13-May-13	0.68	0.28
	2.1	10-Jun-13	0.74	-0.16
#N/A		8-Jul-13	0.74	
	2.8	12-Aug-13	1.1	0.8
	3.0	9-Sep-13	0.7	0.8
	3.0	14-Oct-13	1.05	0.95
	3.0	11-Nov-13	0.87	1.07
	3.1	9-Dec-13	1.01	1.31
	3.2	13-Jan-14	1.45	1.85
	3.2	10-Feb-14	1.48	1.88
	3.2	10-Mar-14	1.37	1.87
	3.2	14-Apr-14	0.91	1.61
	3.3	12-May-14	0.13	1.63
	3.3	9-Jun-14	-0.07	1.53
	3.6	14-Jul-14	0.28	2.08
	3.3	11-Aug-14	0.35	1.85
	3.4	8-Sep-14	0.85	1.95
	3.4	13-Oct-14	0.53	1.93
	3.3	10-Nov-14	0.31	1.71
	3.4	8-Dec-14		2.0
	3.3	12-Jan-15	0.76	2.06
	2.5	9-Feb-15	0.85	1.35
	2.6	9-Mar-15	0.48	1.38
	2.3	13-Apr-15	0.6	0.8
	2.8	11-May-15	0.52	1.42
	2.9	8-Jun-15	0.58	1.78
	2.6	13-Jul-15	0.93	1.53
	2.5	10-Aug-15		
	Mean		0.44	0.94
	Max		1.48	2.10
	Min		-0.91	-0.66

ield (%)

ield Estimate (Consensus Forecasts - 3

ield Estimate (Consensus Forecasts -

ield Estimate - Global Insight IHS - 3

ield Estimate - Global Insight IHS - 12

Forecast (Consensus Forecast)

ahead forecast (Consensus Forecast)

Forecast - IHS Global Insight

ahead forecast - IHS Global Insight

Variance from actual 10-year Government of Canada bond yield
January 2010 - July 2016

	<i>Consensus Forecasts</i>		IHS Global Insights estimate from
	Difference from actual of 3-month forecast	Difference from actual of 12-month ahead forecast	Difference from actual of 3-month forecast
Mean	0.30	0.90	0.44
Max	1.21	2.21	1.48
Min	-0.73	-0.63	-0.91

All numbers are percentages

month end

om Consensus Forecasts	
Difference from actual of 12-month ahead forecast	
	0.94
	2.1
	-0.66

Selected Bond Yields

Monthly series: 2011-08 - 2016-07

V122543 = Government of Canada benchmark bond yields - 10 year

Summary	Date	V122543
Low	7/1/2016	1.07
High	12/1/2013	2.72
Average	2011-08-01 - 2016-07-01	1.89

Date	V122543
2011-08	2.49
2011-09	2.19
2011-10	2.38
2011-11	2.15
2011-12	1.96
2012-01	2.04
2012-02	1.98
2012-03	2.12
2012-04	2.1
2012-05	1.79
2012-06	1.72
2012-07	1.6
2012-08	1.8
2012-09	1.75
2012-10	1.78
2012-11	1.72
2012-12	1.82
2013-01	1.99
2013-02	1.86
2013-03	1.76
2013-04	1.72
2013-05	2.07
2013-06	2.5
2013-07	2.45
2013-08	2.63
2013-09	2.57
2013-10	2.42
2013-11	2.54
2013-12	2.72
2014-01	2.36
2014-02	2.44
2014-03	2.45
2014-04	2.4
2014-05	2.22
2014-06	2.26

2014-07	2.16
2014-08	2
2014-09	2.2
2014-10	2.05
2014-11	1.93
2014-12	1.79
2015-01	1.35
2015-02	1.32
2015-03	1.33
2015-04	1.59
2015-05	1.67
2015-06	1.77
2015-07	1.52
2015-08	1.45
2015-09	1.45
2015-10	1.47
2015-11	1.59
2015-12	1.4
2016-01	1.24
2016-02	1.15
2016-03	1.22
2016-04	1.5
2016-05	1.38
2016-06	1.12
2016-07	1.07

Selected Bond Yields

Monthly series: 2010-01 - 2016-07

V122543 = Government of Canada benchmark bond yields - 10 year

Summary	Date	V122543
Low	7/1/2016	1.07
High	4/1/2010	3.66
Average	2010-01-01 - 2	2.2

Date	V122543
2010-01	3.35
2010-02	3.45
2010-03	3.56
2010-04	3.66
2010-05	3.25
2010-06	3.08
2010-07	3.22
2010-08	2.83
2010-09	2.74
2010-10	2.89
2010-11	3.19
2010-12	3.16
2011-01	3.31
2011-02	3.32
2011-03	3.29
2011-04	3.27
2011-05	3.08
2011-06	3.09
2011-07	2.88
2011-08	2.49
2011-09	2.19
2011-10	2.38
2011-11	2.15
2011-12	1.96
2012-01	2.04
2012-02	1.98
2012-03	2.12
2012-04	2.1
2012-05	1.79
2012-06	1.72
2012-07	1.6
2012-08	1.8
2012-09	1.75
2012-10	1.78
2012-11	1.72

2012-12	1.82
2013-01	1.99
2013-02	1.86
2013-03	1.76
2013-04	1.72
2013-05	2.07
2013-06	2.5
2013-07	2.45
2013-08	2.63
2013-09	2.57
2013-10	2.42
2013-11	2.54
2013-12	2.72
2014-01	2.36
2014-02	2.44
2014-03	2.45
2014-04	2.4
2014-05	2.22
2014-06	2.26
2014-07	2.16
2014-08	2
2014-09	2.2
2014-10	2.05
2014-11	1.93
2014-12	1.79
2015-01	1.35
2015-02	1.32
2015-03	1.33
2015-04	1.59
2015-05	1.67
2015-06	1.77
2015-07	1.52
2015-08	1.45
2015-09	1.45
2015-10	1.47
2015-11	1.59
2015-12	1.4
2016-01	1.24
2016-02	1.15
2016-03	1.22
2016-04	1.5
2016-05	1.38
2016-06	1.12
2016-07	1.07

EP Interrogatory #5

Issue Number: 3.2

Issue: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Reference:

Exhibit A1, Tab 3, Schedule 3, page 5

Has OPG done any analysis that compares its long-term borrowing costs to those of private sector generators? If so, can it please provide those documents.

Response

OPG has not completed such an analysis. No documents are available to provide.

EP Interrogatory #6

Issue Number: 3.2

Issue: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Reference:

Exhibit A1, Tab 3, Schedule 3, page 5

Has OPG done an analysis that compares its credit rating and borrowing costs to private generators? If so, can you please provide those documents.

Response

OPG has not completed such an analysis. No documents are available to provide.

EP Interrogatory #7

Issue Number: 3.2

Issue: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Reference:

Exhibit A1, Tab 3, Schedule 3, Chart 3

1. Has OPG received or provided any comments from ratings agencies regarding its rate smoothing proposal? If so, please provide those documents.
2. Does OPG have any information to suggest that rate smoothing will negatively impact its credit rating?

Response

- 1 OPG has not received or provided comments from rating agencies regarding rate smoothing.
- 2 See response to Ex. L-9.7-015 SEC-94(b).

EP Interrogatory #8

Issue Number: 3.2

Issue: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Reference:

1. Is OPG issuing any long-term debt that is specifically related to capital spending on the DRP?
2. Can OPG provide a table – or point to it in the evidence – of the amount of long-term debt that the company expects to issue annually from 2015-2021

Response

1. No. As stated at Ex. C1-1-2 page 5, OPG does not plan to issue any additional project-related financing for the regulated assets during the bridge and test periods.
2. No debt was issued in 2015. Forecasted issuance of long term debt is captured in the evidence at Ex.C1-1-2 Chart 3, and in Ex. C1-1-2 Tables 4-10.

LPMA Interrogatory #1

Issue Number: 3.2

Issue: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Reference:

Ref: Exhibit C1, Tab 1, Schedule 2

a) Please update Charts 1 and 2 to reflect the most recent Global Insight forecast available, including actual 10 year Long Canada Bond Rates for the first three quarters of 2016.

b) Please provide the 3 month and 12 month ahead forecast for 10 year Long Canada Bond Rates from the most recent Consensus Forecasts for the period available from that publication.

Response

a)

**Chart 1:
Forecast 10-year Long Canada Bond Rates (%)**

Year	Q1	Q2	Q3	Q4
2016	1.20	1.33	1.02	1.39
2017	1.69	1.84	2.04	2.17
2018	2.34	2.43	2.62	2.76
2019	2.90	3.11	3.37	3.44
2020	3.44	3.44	3.44	3.44
2021	3.44	3.44	3.44	3.44

Chart 2:
Forecast 10-year Long Canada Bond Rates
including Credit Risk Spread (%)

Year	Q1	Q2	Q3	Q4
2016	2.81	2.94	2.63	3.00
2017	3.30	3.45	3.65	3.78
2018	3.95	4.04	4.23	4.37
2019	4.51	4.72	4.98	5.05
2020	5.05	5.05	5.05	5.05
2021	5.05	5.05	5.05	5.05

Chart 3:
3 month and 12 month ahead forecast for 10 year Long Canada Bond Rates (%)

3 Months	12 Months
1.2	1.6

LPMA Interrogatory #2

Issue Number: 3.2

Issue: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Reference:

Ref: Exhibit C1, Tab 1, Schedule 2, Table 5a

a) What is the status of the two notes shown in the table (Issue 29 & 30) with issue dates of 3/22/2016 and 9/22/2016?

b) Please update the tables shown for Issues 29 and 30 that shows the GOC and OPG Spread.

c) Does OPG propose to fix the forecast rate for the new long term debt issues as part of this application, or would they be updated annually to reflect actual issuances and rates and the forecast issuances and rates for the following year, as is the proposal for the return on equity?

Response

a) Issues 29 & 30 have not yet been issued. OPG plans to issue debt in November 2016.

b) A revised copy of Table 5a is provided at Attachment 1, showing a forecast to issue \$200M of new debt in November, 2016. OPG is not forecasting to issue the additional \$200M in debt (i.e. Note 2, Issue 30 from Ex. C1-1-2 Table 5a).

c) As discussed in Ex. L-3.2-1-Staff-23, OPG is not proposing to update the debt rates annually.

Numbers may not add due to rounding.

Filed: 2016-10-26
EB-2016-0152
Exhibit L
Tab 3.2
Schedule 11 LPMA-002
Attachment 1
Table 5a

Table 5a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt (\$M)
Outstanding During Calendar Year Ending Dec. 31, 2016
Notes to Ex. C1-1-2, Table 5

	Issue	Issue Date	Face Value (\$M)	Effective Days	Weighted Principal (\$M)
Note 1	Issue 29	11/22/2016	200.0	39.0	21.4
Note 2	Issue 30				
	Issue	Maturity Date	Face Value (\$M)	Effective Days	Weighted Principal (\$M)
Note 3	Niagara 1	10/22/2016	160.0	296.0	129.8

Note 4 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (c). The 2015 allocation ratio is used as it reflects OPG's most recent financial results.

Note 5 See Ex. C1-1-2 Table 2a, Note 4

Note 6 Future issue rate reference Global Insight (January 2016).

Note 2 Not Issued

Issue 29

GOC & OPG Spread	
GOC Q4-16	2.26%
OPG Spread	1.61%
Effective Rate	3.87%

LPMA Interrogatory #3

Issue Number: 3.2

Issue: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Reference:

Ref: Exhibit C1, Tab 1, Schedule 2, Tables 5 through 10

For each year in 2016 through 2021 as shown in Tables 5 through 10, respectively, please show the percentage of long term debt that is currently issued and the percentage of long term debt that is forecast to be issued, but has not yet been issued.

Response

Chart 1

Year		\$M	%
2016	Existing Debt	2,994.8	93
	New Debt	210.0	7
2017	Existing Debt	2,580.2	69
	New Debt	1,163.8	31
2018	Existing Debt	1,857.7	44
	New Debt	2,334.5	56
2019	Existing Debt	1,629.6	35
	New Debt	3,065.6	65
2020	Existing Debt	1,177.5	24
	New Debt	3,651.9	76
2021	Existing Debt	779.5	16
	New Debt	3,952.6	84

New debt is cumulative as proposed in Ex. C1-1-2 Tables 5-10

LPMA Interrogatory #4

Issue Number: 3.2

Issue: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Reference:

Ref: Exhibit C1, Tab 3, Schedule 2

The evidence states that the borrowing rate under the commercial paper program is based on a 10 basis point dealer fee and a corporate spread over the bankers' acceptances rate of 5 basis points.

a) What bankers' acceptance rate is being referred to (1 month, 3 month)?

b) Please provide the most recent forecast available from Global Insight for the bankers acceptance rate used in the calculation.

c) Does OPG propose to fix the forecast for the short term debt rate as part of this application, or would the short term rate be updated annually as is the return on equity?

Response

OPG believes the intended reference for this interrogatory was Exhibit C1, Tab 1, Schedule 3.

a) The bankers' acceptance rate is 3 months.

b) The Global Insight forecast from September 9, 2016 is provided in Chart 1:

Chart 1

		2016	2017	2018	2019	2020	2021
3-Month Rate	T-Bill	0.50%	0.51%	1.24%	2.74%	3.01%	3.01%

c) As discussed in Ex. L-3.2-1-Staff-23, OPG is not proposing to update the debt rates annually.

VECC Interrogatory #12

Issue Number: 3.2

Issue: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Reference:

Ref: C1/T1/S2/pg.5

OPG uses the Global Insight forecast for the 10 year Canada yield as the basis for its own forecast borrowing cost:

- a) Please indicate any analysis that OPG has performed to justify its implicit assumption that Global Insight's forecast are accurate.
- b) Please provide the latest Global Insight forecast and if none is available indicate the current 10 year Canada yield and the rate on January 1, 2016.
- c) Please indicate why OPG does not use the forecast ten year yield incorporated into the current yield curve. If it lacks the internal skills please explain why it cannot ask the staff at OEFC for an estimate.
- d) Please confirm that the current forecast by the Royal Bank of Canada (FMM, September 9, 2016) has the 10 year Canada rate at 1.25% at the end of 2016, Q4 and 1.90% as of 2017, Q4 versus the Global Insight values used by OPG of 2.26% (1.01% higher) and 2.48% (0.58% higher)

Response

- a) OPG uses an external forecasting service to provide an independent view of interest rates, and does not perform any incremental analysis.
- b) See Ex. L-3.2-Staff-22-Attachment 1.
- c) Any yield curve represents a point in time estimate of the yields on different bond maturities. The yield curve itself is dependent on which market data service calculated the yield curve and information supporting that curve. The yield curve will change more frequently than forecasts provided by an external forecast service. OPG uses an external forecasting service to provide an independent view of interest rates.

- d) The RBC FMM forecast and the Global Insight forecast were published at different points in time and, as such, are not directly comparable. Chart 1 below lists the forecast for 10 year Government of Canada bonds as at Q4 2016 and Q4 2017 published in January and September. The January 2016 RBC forecast for 2017 was higher than GI however the September forecast has RBC lower than GI.

Chart 1

	January 2016 Forecast		September 2016 Forecast	
	Govt of Cda 10 year – 2016 Q4	Govt of Cda 10 year – 2017 Q4	Govt of Cda 10 year – 2016 Q4	Govt of Cda 10 year – 2017 Q4
Global Insight forecast	2.26	2.48	1.39	2.17
RBC FMM forecast	2.30	3.15	1.25	1.90

VECC Interrogatory #13

Issue Number: 3.2

Issue: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Reference:

Reference: C1/T1/S3 Cost of short term debt

- a) Please include the critical details of \$1 billion bank facility that was renewed in May 2016 and discussed at page 1
- b) Given the small size of its commercial paper issue please discuss and contrast the total cost of OPG using its own name to issue commercial paper versus issuing Bankers Acceptances or simply borrowing on a credit line from its bank.
- c) Please confirm that the RBC forecast for the 91 day T Bill yield is 0.50% for 2016, Q4 and 0.60% for 2017, Q4.
- d) Please confirm that the \$2.6 million allocated to the bank credit facility represents an annual cost of 6.5% at the forecast \$2.6 million annual cost on an average outstanding balance of \$40 million (2.6/40).
- e) OPG forecasts that its short term debt cost for 2016 is 2.9% rising to 4.1% in 2021, please tie this cost into the terms of the new credit facility.
- f) Please indicate the current all in cost of issuing one year notes and why OPG would not simply issue such notes and leave the cash on deposit to fund its short term needs.

Response

- a) As discussed in prior applications: EB-2007-0905 C1-2-3 page 1

OPG "maintains a bank credit facility as the primary backstop to its commercial paper program. The bank credit facility provides protection to commercial paper investors by allowing OPG to borrow by way of bankers' acceptances in the event OPG is unable to re-issue its commercial paper in the market place."

In this application at Ex C1-1-3 OPG discusses that the bank facility is \$1B in size, comprised of two \$500M multi-year tranches. In May 2016, OPG extended both tranches to May 2021.

1 This facility is needed in order to issue commercial paper and borrowing directly out of
2 the facility would only be used if OPG was unable to issue commercial paper which is not
3 expected.
4

5 b) Table 2 at Ex. C1-1-3 shows the average daily balance of commercial paper. Actual
6 commercial paper outstanding varies dramatically in amount throughout the year as OPG
7 generally issues commercial paper intra-month to fund cash requirements to the next
8 revenue day. In 2015 the largest amount of commercial paper outstanding was \$300
9 million for 5 days. Loans under the credit facility have a minimum term of 1 month and
10 attract a margin on top of the loan rate which makes this funding approach significantly
11 more expensive than the all-in cost of commercial paper.
12

13 c) Confirmed (see Attachment 1, Page 5).
14

15 d) The noted calculation is incorrect as it attributes the value of credit facility to only the
16 average amount of commercial paper. As noted in the response to part (b) the average
17 balance does not capture the intra-month changes in the amount of commercial paper.
18 In addition, the credit facility provides financial value beyond commercial paper support.
19 The credit facility provides a key source of liquidity which is an area assessed by credit
20 rating agencies (see rating agency reports in A2-3-1). Companies without adequate
21 liquidity face greater credit risks and potentially lower credit ratings which result in higher
22 financing costs. A committed credit facility is a prudent practice to ensure funds are
23 available when required and is also a positive credit rating factor.
24

25 e) OPG forecasts its short term debt costs are \$2.9 million in 2016 rising to \$4.1 million by
26 2021. The components of these amounts are specified at Ex. C1-1-3 Table 2. The credit
27 facility cost is forecast to be \$2.6M for the years 2016-2021.
28

29 f) As noted in response to part (b) OPG's actual cash requirements vary dramatically
30 throughout the month. Estimated borrowing rates for a 1 year term exceed bank account
31 rates by about 1.1%. The suggested approach is not cost effective as OPG would incur a
32 net cost for every dollar borrowed.

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FINANCIAL MARKETS MONTHLY

September 9, 2016

Ups and downs

Getting a true read on G7 economies has not been easy lately. The UK's Brexit vote threw a spanner in the works to start the summer, and more than two months later, it is still not clear how the economy is faring after the referendum. Surveys have given mixed signals, most notably the UK's closely watched Purchasing Managers' Index (PMI) fell sharply into contractionary territory in July only to rebound fully in August. Getting a sense of the trend has not been easy in Canada either, where temporary oil production outages led to a sizeable decline in second-quarter gross domestic product (GDP). We expect a strong rebound in the third quarter as production resumes, but separately, concerns about the rotation toward non-energy exports linger. In the US, growth and employment have been sending different signals about the state of the economy, although there are indications that activity is finally picking up in the third quarter after a disappointing slowdown since the end of 2015.

Financial markets kept a level head amid these ups and downs. Global equity prices, as measured by the MSCI World Index, crept higher since the start of August, and volatility during that month was the lowest in more than a year. Investors were likely soothed by another round of monetary policy stimulus as central banks continue to fight low inflation globally. The Bank of England (BoE) announced a comprehensive stimulus package to address fallout from the Brexit vote, and the Reserve Banks of Australia (RBA) and New Zealand (RBNZ) both lowered rates in August. The Bank of Japan (BoJ) and European Central Bank (ECB) continue to add to their balance sheets, with the latter studying options to tweak its asset purchase program to ensure it can continue to buy bonds at least through March 2017. While equities were buoyed, those measures did not have much of an effect on already low government bond yields as they were largely anticipated by markets and came alongside an improvement in risk appetite.

Central bank near-term bias

Three-months out, policy rate



The BoC did not display the same sense of optimism that it had in July, noting that non-energy exports have disappointed and risks to the inflation outlook are now tilted to the downside. We expect the Bank will keep the door ajar to another rate cut, but any additional easing appears unlikely.



The Fed's September meeting will give us a better idea of whether the Committee is leaning toward a rate hike later this year. Barring a significant shift in tone, we expect that the Fed will not arrive at a consensus to raise rates by December.



The BoE announced a number of stimulus measures in August to deal with Brexit fallout. If its forecast that growth will stall in H2/16 plays out (which we expect it will), then we look for the Bank Rate to be cut to 0.10% in November.



We continue to expect the ECB will have to tweak some of the parameters of its asset purchase program to allow for purchases to continue at least to March 2017. Draghi hinted at as much, saying that a review to ensure "smooth implementation" is currently underway.



The RBA appeared content with the current stance of monetary policy following August's rate cut, and with a new governor now taking the helm, we do not expect any changes for the rest of the year.



The RBNZ delivered on an expected rate cut in August and showed no signs that the easing cycle is nearing an end. We expect another 25 basis point rate cut in September to be followed by further easing next year.

Highlights

- ▲ Market volatility ebbed following the Brexit shock, helped by stimulus from a number of central banks.
- ▲ The US economy appears to be perking up after a disappointing H1/16.
- ▲ Job growth slowed in August but continued to be strong enough to absorb remaining labour market slack.
- ▲ Chair Yellen's highly anticipated Jackson Hole speech was light on policy guidance, making September's post-meeting statement all the more important to gauge the Fed's thinking.

US economy shaping up for a solid Q3/16

The revised estimate of second-quarter GDP confirmed that the US economy continued to grow at a disappointingly slow pace, with a 1.1% annualized increase (was 1.2%) barely picking up from the sub-1.0% gains in the prior two quarters. A sizeable pullback in inventory investment was responsible for some of the weakness, and a surge in consumer spending helped boost domestic demand north of 2.0% despite a further decline in business investment. On a year-over-year basis, the economy is now growing at its weakest pace in three years, but there are indications that overall activity will improve from here. With a solid labour market and rising real wages, there is little to suggest that consumer spending, the lone source of growth in the first half of 2016, is beginning to fade. Auto sales jumped to a year-to-date high in July, and even with some moderation in August, spending on durable goods is poised to build on the second quarter's 10% annualized gain. As well, residential investment is poised for a return to growth with housing starts having surged close to a cycle-high to start the third quarter.

Two sources of recent weakness also appear to be turning. Oil and gas investment is nearing a trough, with the third quarter potentially seeing the first increase in drilling rigs since oil prices began to collapse in the second half of 2014. A solid rise in construction spending outside the energy sector also points to non-residential investment picking up. Even with spottier evidence of a pickup in machinery and equipment spending (capex orders up but shipments down), we expect business investment growth will turn positive in the third quarter after three consecutive declines—the worst streak since the 2008-09 recession. We also look for businesses to begin rebuilding inventories after five quarters of slowing. With these two key drags on the economy lifted, our forecast assumes growth will bounce back to a 3.2% annualized pace in the third quarter, which would be the strongest gain in two years.

A lukewarm labour market report...

August's jobs report was perhaps even more highly anticipated than usual, with another strong gain potentially opening the door further to a September rate hike. In the event, a 151,000 increase in non-farm payrolls fell short of consensus, although that pace can hardly be considered disappointing given recent strength and what is likely a much lower run rate reflecting demographic factors and limited labour market slack. The unemployment rate was steady at 4.9%; however, some softness was evident with a dip in the average workweek and slight moderation in wage inflation. Although it remains the case that wage growth has picked up for more than a year, at an annual pace of 2.4% in August, it is hard to argue that wage pressure is inflationary enough at present to force the Fed's hand on a rate hike.

...won't be enough for a September hike

Without an unambiguously positive payroll report, expectations for a rate hike at the September 21 meeting remain low. There was little to indicate that a consensus was building among policymakers at the July meeting, and data since then have likely done little to bridge the gap, providing something for both the doves (slow GDP growth and well behaved inflation) and hawks (further improvement in the labour market and relative calm in financial markets post-Brexit vote). For her part, Chair Yellen noted the case for a rate hike has strengthened in recent months, but her much-anticipated Jackson Hole speech gave few hints on the timing of any action.

While we do not expect a move in September, the meeting and press conference (and, more explicitly, the updated 'dot plot') should provide some clues as to whether the Committee is leaning toward a rate hike later this year. Markets are pricing in roughly 50/50 odds of a rate hike in December, and we are similarly sceptical that the Fed is prepared to tighten. Even if our expected rebound in GDP growth materializes in the second half of 2016, some of the more dovish Committee members will likely still be reluctant to raise rates in the absence of greater inflationary pressure. Policymakers also have cause to play it safe amid the uncertainty generated by money market reform that has already affected financial institutions' funding costs and could filter to the real economy through wider credit spreads. Absent a notable shift in the Fed's tone in September, we continue to expect higher policy rates will be a 2017 story.

Highlights

Canada's ugly Q2 GDP reflects a wildfire-driven slowdown

Canadian GDP fell by an annualized 1.6% in the second quarter, the worst outturn since the 2008-09 recession. The decline was in line with consensus estimates, however, and largely reflected temporary supply disruptions in the oil sector related to wildfires in Alberta. The oil production outages that began in May and extended into June contributed to energy exports falling by an annualized 27% in the quarter. Factoring in the disappointing weakness in non-energy exports, which saw a sizeable pullback following first-quarter strength, net exports subtracted nearly 6 percentage points from headline GDP growth. Another quarter of solid consumer spending provided some offset, as wealth effects in areas experiencing booming housing markets likely supplemented what has been fairly soft employment growth so far this year. Non-residential investment declined for a sixth consecutive quarter, although the most recent dip was by far the smallest in that period, with the machinery and equipment component actually posting a modest gain.

June rebound provides optimism for Q3

Underlying the quarterly growth numbers, June GDP showed a solid 0.6% monthly increase that retraced the 0.6% decline seen in May. The gain was led by a rebound in oil and gas production, although it did not fully retrace May's drop because some production remained offline in June. An increase in manufacturing output also provided support following a decline in the previous month that partly reflected auto parts supply disruptions associated with an earthquake in Japan. The increase in June GDP provided a solid jumping off point for the third quarter, and with some oil production still to be made up, we expect another above-trend increase in July. The full return of oil shipments will help boost energy exports, and recent trade data provide a glimmer of hope that the recent pullback in non-energy exports is beginning to reverse. As such, we expect net trade will make a positive contribution to growth in the third quarter. Our forecast also assumes a return to growth in business investment as the drag from the energy sector appears to be abating with rig counts flattening out. All told, we look for a 3.7% annualized rebound in third-quarter GDP, which is similar to the Bank of Canada's latest forecast for a 3.5% gain.

BoC takes on a more dovish tone in September

Although we had not heard from the Bank of Canada since mid-July, there was little fanfare going into its September meeting—the wildfire-related swing in GDP growth appeared to be playing out largely as expected (even if the hit to the energy sector was slightly greater than the central bank had anticipated), and the Bank previously sounded unperturbed by weakness in non-energy exports. There was, however, a slight shift in tone in the Bank's latest commentary, particularly on trade. The statement noted that the second-quarter decline in exports was larger and more broadly based than expected, with that weakness not fully accounted for by traditional drivers of trade (including US investment) or temporary factors. Even with some rebound in non-energy exports in July, this raised the prospect that net exports would fall short of contributing nearly a percentage point to GDP growth this year. The Bank is holding out hope that fiscal stimulus, including the Child Care Benefit payments that began in July, will boost the economy beyond the third-quarter rebound from returning oil production and rebuilding in Alberta. On balance, however, policymakers now see risks to the inflation outlook as tilted to the downside.

The Bank again voiced concern about elevated and rising household imbalances. Sales in the Vancouver area have begun to moderate, due in part to changes in government regulation, but affordability remains a significant concern, and there are fewer signs of cooling in other markets. While the Bank appears to be leaving the door ajar to further monetary policy accommodation if growth disappoints, we think household indebtedness and housing market imbalances present a significant obstacle to lowering rates at this stage, even if the Bank sees its role in correcting imbalances as limited. The federal government's stimulus has only begun to flow, with infrastructure investment still yet to gear up, and we think the Bank's risk management framework will favour leaving rates steady and allowing fiscal policy to do some of the heavy lifting.

▲ Oil-production outages pushed GDP into negative territory but that was not the only source of disappointment as non-energy exports fell substantially in Q2/16.

▲ June's 0.6% rebound in GDP provided a solid starting point for Q3/16, but we will need to see another above-trend gain in July to push growth above 3.0%.

▲ The BoC now sees risks to the outlook as tilted to the downside, but with the policy mix shifting toward fiscal stimulus, we do not think that another rate cut is likely or needed.

Highlights

▲ UK PMI readings are providing inconsistent signals and we continue to expect the economy stagnated in Q3.

▲ The euro area had seen broad-based growth from its major economies in earlier quarters, but that was not the case in Q2/16.

▲ Few changes were expected in September's policy statement, which was the last from outgoing RBA Governor Stevens.

▲ We now expect an additional 50 basis points of easing from the RBNZ, beginning with the next meeting in September.

Swing in UK surveys underscores Brexit uncertainty

While we expected the UK economy would enter a period of stagnation following the surprise Brexit vote on June 23, sharp deterioration in survey data in July raised the prospect that the slowdown would be even more severe than anticipated. Sentiment, however, unexpectedly rebounded in August with PMI readings generally returning to pre-referendum levels. While this volatility underscored the uncertainty facing the UK economy after the vote, we expect conditions were neither as weak as the July surveys indicated nor were they as strong as August's data would suggest. With mixed signals from the PMIs and hard data only beginning to filter in, we remain comfortable expecting a modest 0.1% decline in third-quarter GDP with the economy continuing to stagnate in coming quarters. Our forecast assumes the slowdown will initially be reflected in weaker business investment amid uncertainty about the UK's future access to the Single Market, with attendant slower job growth and a squeeze on real incomes weighing on consumer spending over time. In an attempt to mitigate the effect of these headwinds, the BoE announced a slew of stimulus measures in early August including a 25 basis point rate cut, another round of asset purchases, and other measures to ensure credit flows to the real economy. Should incoming data confirm the Bank's expected slowdown (it anticipates little growth in the second half of 2016), we see the Bank Rate being lowered to 0.10% in November, effectively maxing out conventional monetary policy stimulus but by no means leaving the BoE without additional options.

Euro area showing few signs of Brexit spillover

Euro area growth moderated to 0.3% (non-annualized) in the second quarter, which was the slowest pace since the recovery began to build momentum two years ago. The slowdown reflected more narrowly based growth than we have seen recently, as GDP in both Italy and France was little changed following several consecutive quarters of positive growth. Recent data continued to show little immediate effect from the UK's Brexit vote. The euro area's composite PMI edged downward only slightly in August and was in line with readings that have prevailed for much of 2016. Inflation remains stubbornly low, however, with the headline reading hovering near zero in recent months while core inflation continues to move sideways. That is keeping pressure on the ECB to provide stimulus, and we continue to expect changes to the parameters of the central bank's asset purchase program that will allow the current pace of purchases to be maintained at least until March 2017. ECB President Draghi noted that a review is underway to ensure "smooth implementation" of the purchase program, although we await further information to see just how far those changes will go.

RBA shows little bias as new governor set to take the reins

Australian GDP growth slowed to a 0.5% non-annualized pace in the second quarter, roughly in line with expectations. The underlying details were mixed with a poor composition of growth (concentrated in government spending and inventory investment) but some improvement in nominal measures, including the first increase in the terms of trade in more than two years. With some further recovery in key commodity prices in the third quarter, we may have seen the trough in terms of trade after a 40% decline since 2011. Alongside signs that the investment outlook is improving, it appears that two key drags on Australia's economy are beginning to ease. That said, we continue to view slow wage growth, a disinflationary global backdrop and a sticky currency as arguing for an accommodative policy stance and see scope for an additional rate cut next year. There was little hint of an easing bias in outgoing RBA Governor Steven's final policy statement, however, with few changes relative to the prior month and a concluding statement that sounded satisfied with the current policy stance following August's rate cut.

RBNZ set to lower rates again in September

The RBNZ delivered an expected rate cut in August of 25 basis points to 2.00% and, perhaps more significantly, maintained a strong easing bias with forecasts implying another 25 to 50 basis points of easing. We see weak headline inflation, falling inflation expectations, and a stubbornly high exchange rate as providing scope for additional cuts going forward. With the RBNZ making its intentions more explicit, we now forecast the easing cycle will continue with the cash rate being lowered to 1.50%. We expect the first of these cuts will be delivered in September and followed up by another move early next year.

Interest rate outlook

%, end of period

	<i>Actuals</i>						<i>Forecast</i>					
	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4	17Q1	17Q2	17Q3	17Q4
Canada												
Overnight	0.75	0.75	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Three-month	0.55	0.58	0.43	0.51	0.45	0.48	0.50	0.50	0.50	0.50	0.55	0.60
Two-year	0.50	0.48	0.52	0.48	0.54	0.52	0.55	0.60	0.60	0.65	0.70	0.80
Five-year	0.77	0.82	0.80	0.73	0.67	0.57	0.65	0.75	0.80	0.95	1.15	1.35
10-year	1.36	1.69	1.43	1.40	1.23	1.06	1.15	1.25	1.40	1.60	1.75	1.90
30-year	1.98	2.31	2.20	2.15	2.00	1.72	1.80	1.90	2.05	2.25	2.45	2.65
United States												
Fed funds**	0.25	0.25	0.25	0.50	0.50	0.50	0.50	0.50	0.50	0.75	0.75	1.00
Three-month	0.03	0.01	0.00	0.16	0.21	0.26	0.20	0.20	0.15	0.50	0.50	0.75
Two-year	0.56	0.64	0.64	1.06	0.73	0.58	0.70	0.80	0.90	1.00	1.15	1.25
Five-year	1.37	1.63	1.37	1.76	1.21	1.01	1.10	1.20	1.30	1.40	1.55	1.65
10-year	1.94	2.35	2.06	2.27	1.78	1.49	1.55	1.70	1.80	1.90	2.00	2.10
30-year	2.54	3.11	2.87	3.01	2.61	2.30	2.30	2.40	2.60	2.75	2.85	2.90
United Kingdom												
Bank rate	0.50	0.50	0.50	0.50	0.50	0.50	0.25	0.10	0.10	0.10	0.10	0.10
Two-year	0.43	0.55	0.56	0.66	0.45	0.13	0.10	0.10	0.10	0.10	0.10	0.10
10-year	1.58	2.01	1.76	1.96	1.43	0.89	0.85	0.90	1.00	1.10	1.20	1.25
Euro area												
Deposit Rate	-0.20	-0.20	-0.20	-0.30	-0.40	-0.40	-0.40	-0.40	-0.40	-0.40	-0.40	-0.40
Two-year	-0.25	-0.23	-0.26	-0.34	-0.48	-0.61	-0.70	-0.60	-0.60	-0.60	-0.60	-0.60
10-year	0.18	0.77	0.59	0.63	0.15	-0.11	-0.25	0.00	0.00	0.10	0.20	0.25
Australia												
Cash target rate	2.25	2.00	2.00	2.00	2.00	1.75	1.50	1.50	1.50	1.25	1.25	1.25
Two-year	1.72	2.01	1.81	2.02	1.89	1.59	1.40	1.40	1.30	1.20	1.20	1.30
10-year	2.32	3.01	2.61	2.88	2.49	1.98	1.95	2.10	2.10	2.20	2.40	2.50
New Zealand												
Cash target rate	3.50	3.25	2.75	2.50	2.25	2.25	1.75	1.75	1.50	1.50	1.50	1.50
Two-year swap	3.48	3.09	2.69	2.83	2.19	2.22	1.90	1.90	1.80	1.75	1.75	1.90
10-year swap	3.71	3.89	3.48	3.73	2.97	2.65	2.50	2.60	2.60	2.60	2.70	2.80
Yield curve*												
Canada	86	121	91	92	69	54	60	65	80	95	105	110
United States	138	171	142	121	105	91	85	90	90	90	85	85
United Kingdom	115	146	120	130	98	76	75	80	90	100	110	115
Eurozone	43	100	85	97	63	50	45	60	60	70	80	85
Australia	60	100	80	86	60	39	55	70	80	100	120	120
New Zealand	23	80	79	90	78	43	60	70	80	85	95	90

* Two-year/10-year spread in basis points, **Top of 25 basis point range,

Source: Reuters, RBC Economics Research

Central bank policy rate

%, end of period

		Current	Last				Current	Last	
United States	Fed funds	0.25-0.50	0.0-0.25	December 16, 2015	Eurozone	Deposit rate	-0.40	-0.30	March 10, 2016
Canada	Overnight rate	0.50	0.75	July 15, 2015	Australia	Cash rate	1.50	1.75	August 3, 2016
United Kingdom	Bank rate	0.25	0.50	August 4, 2016	New Zealand	Cash rate	2.00	2.25	August 11, 2016

Source: Bloomberg, Reuters, RBC Economics Research



Economic outlook

Growth outlook

% change, quarter-over-quarter in real GDP

	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4	17Q1	17Q2	17Q3	17Q4	2014	2015F	2016F	2017F
Canada*	-1.0	-0.5	2.2	0.5	2.5	-1.6	3.7	1.9	1.9	1.8	1.6	1.6	2.5	1.1	1.3	1.8
United States*	2.0	2.6	2.0	0.9	0.8	1.1	3.2	2.7	2.3	2.1	2.0	1.9	2.4	2.6	1.6	2.3
United Kingdom	0.3	0.4	0.4	0.7	0.4	0.6	-0.1	0.1	-0.1	0.0	0.0	0.1	3.1	2.2	1.6	0.1
Euro area	0.8	0.4	0.4	0.4	0.5	0.3	0.2	0.2	0.3	0.3	0.4	0.4	1.1	1.9	1.5	1.2
Australia	0.9	0.2	1.0	0.7	1.0	0.5	0.6	0.7	0.7	0.7	0.7	0.8	2.7	2.4	3.0	2.7
New Zealand	0.2	0.3	0.8	0.9	0.7	0.5	0.5	0.5	0.5	0.5	0.6	0.6	3.7	2.5	1.8	2.1

*annualized,

Inflation outlook

% change, year-over-year

	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4	17Q1	17Q2	17Q3	17Q4	2014	2015F	2016F	2017F
Canada	1.1	0.9	1.2	1.3	1.5	1.6	1.5	2.0	2.4	2.5	2.5	2.2	2.0	1.1	1.7	2.4
United States	-0.1	0.0	0.1	0.5	1.1	1.1	1.1	1.6	2.3	2.2	2.4	2.4	1.6	0.1	1.2	2.3
United Kingdom	0.1	0.0	0.0	0.1	0.3	0.4	0.7	1.1	1.9	2.4	2.2	1.9	1.5	0.0	0.6	2.1
Euro area	-0.3	0.2	0.1	0.2	0.0	-0.1	0.3	0.4	0.8	1.2	1.4	1.5	0.4	0.0	0.2	1.2
Australia	1.3	1.5	1.5	1.7	1.3	1.0	1.2	1.4	2.2	2.5	2.6	2.7	2.5	1.5	1.2	2.5
New Zealand	0.3	0.4	0.4	0.1	0.4	0.4	0.6	1.4	1.5	1.5	1.5	1.6	1.2	0.3	0.7	1.6

Source: Statistics Canada, Bureau of Labor Statistics, Bank of England, European Central Bank, Reserve Bank of Australia, Reserve Bank of New Zealand, RBC Economics Research

Inflation tracking

Inflation Watch

	Measure	Current period	Period ago	Year ago	Three-month trend	Six-month trend
Canada	Bank of Canada core CPI ¹	Jul	0.1	2.1	2.5	2.2
United States	Core PCE ^{1,2}	Jul	0.1	1.6	1.6	1.8
United Kingdom	All-items CPI	Jul	0.0	0.6	1.9	0.3
Euro area	All-items CPI ¹	Aug	0.0	0.2	1.7	0.5
Australia	Trimmed mean CPI ¹	Q2	0.5	1.7	N/A	N/A
New Zealand	All-items CPI	Q2	0.4	0.4	N/A	N/A

¹ Seasonally adjusted measurement.

² Personal consumption expenditures less food and energy price indices.

Source: Statistics Canada, US Bureau of Labor Statistics, Bank of England, European Central Bank, Reserve Bank of Australia, Reserve Bank of New Zealand, RBC Economics Research

Currency outlook

Level, end of period

	Actuals						Forecast					
	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4	17Q1	17Q2	17Q3	17Q4
Canadian dollar	1.27	1.25	1.33	1.38	1.30	1.29	1.31	1.33	1.31	1.31	1.30	1.30
Euro	1.07	1.11	1.12	1.09	1.14	1.11	1.11	1.10	1.08	1.07	1.06	1.05
U.K. pound sterling	1.48	1.57	1.51	1.47	1.44	1.33	1.32	1.25	1.15	1.15	1.16	1.18
New Zealand dollar	0.75	0.68	0.64	0.68	0.69	0.71	0.74	0.78	0.80	0.78	0.77	0.76
Japanese yen	120.1	122.5	119.9	120.1	112.6	103.2	99.0	97.0	95.0	92.0	95.0	97.0
Australian dollar	0.76	0.77	0.70	0.73	0.77	0.75	0.77	0.79	0.79	0.76	0.74	0.72

Canadian dollar cross-rates

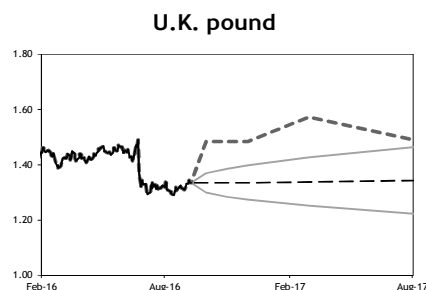
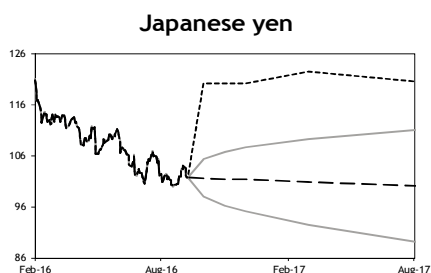
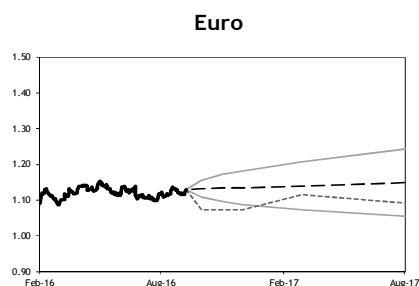
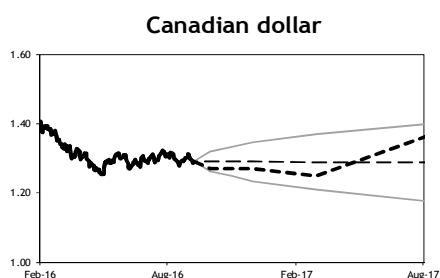
	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4	17Q1	17Q2	17Q3	17Q4
EUR/CAD	1.36	1.39	1.49	1.50	1.48	1.43	1.45	1.46	1.41	1.40	1.38	1.37
GBP/CAD	1.88	1.96	2.01	2.04	1.87	1.72	1.73	1.66	1.51	1.51	1.51	1.53
NZD/CAD	0.95	0.85	0.85	0.95	0.90	0.92	0.97	1.04	1.05	1.02	1.00	0.99
CAD/JPY	94.7	98.0	90.0	86.8	86.6	79.9	75.6	72.9	72.5	70.2	73.1	74.6
AUD/CAD	0.97	0.96	0.93	1.01	1.00	0.96	1.01	1.05	1.03	1.00	0.96	0.94

Rates are expressed in currency units per US dollar and currency units per Canadian dollar, except the euro, UK pound, Australian dollar, and New Zealand dollar, which are expressed in US dollars per currency unit and Canadian dollars per currency unit.

Source: Bloomberg, RBC Economics Research

RBC Economics outlook compared to the market

The following charts track historical exchange rates plus the forward rate (dashed line) compared to the RBC Economics forecast (dotted line) out one year. The cone for the forecast period frames the forward rate with confidence bounds using implied option volatilities as of the date of publication.

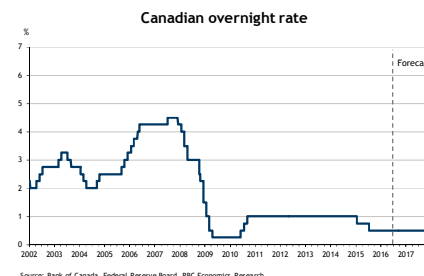


Central bank watch

Bank of Canada

The 1.6% annualized decline in Q2/16 GDP reflected temporary supply outages in the oil sector, and we are with the BoC in projecting a rebound of more than 3.0% in Q3 as oil production returns to earlier levels.

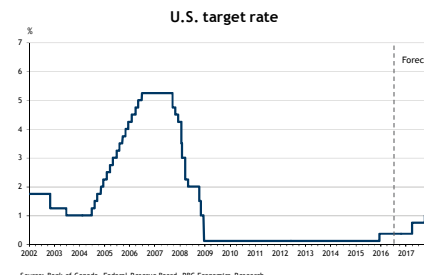
The BoC acknowledged recent underperformance in non-energy exports but continues to look for fiscal stimulus to support growth beyond the economy's Q3 rebound.



Federal Reserve

US GDP growth disappointed again in Q2/16, but there are indications that the drag from investment is easing, which should help growth pick up above 3% in Q3.

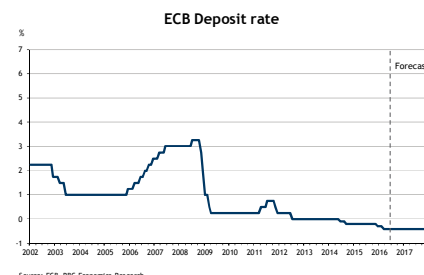
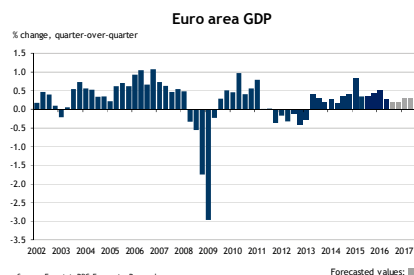
With recent data providing something for both the doves and hawks, we do not see the FOMC moving toward a consensus to raise rates in September. Absent a clear shift in tone, we expect the Fed will hold policy steady through the end of 2016.



European Central Bank

Euro area growth moderated to its weakest pace in more than two years as both Italy and France lost momentum. We expect growth will continue at a fairly subdued pace in H2/16.

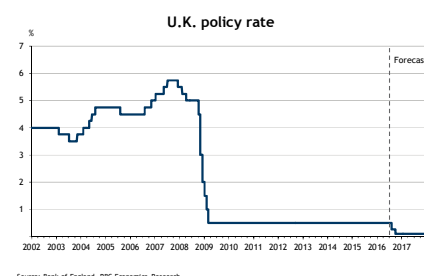
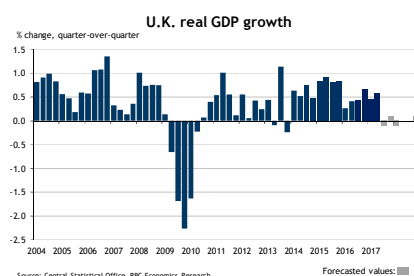
The ECB's September meeting resulted in no policy changes, although the parameters of the central bank's asset purchase program are being reviewed to ensure the current pace of buying can continue into 2017.



Bank of England

With PMI data bouncing around in July and August and hard data post-Brexit vote only beginning to filter in, we continue to expect the UK economy slowed in Q3/16.

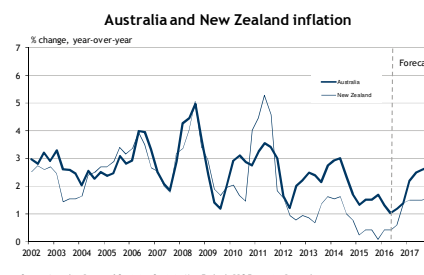
The BoE announced a sizeable stimulus package in August, and if the data align with its forecast for little growth in GDP during H2/16, then we would expect another rate cut in November.



Australia and New Zealand

Australia's latest set of national accounts indicated that some of the drag from terms of trade and capex is abating, but we expect weak wage growth, low inflation, and a stubbornly strong currency will prompt another rate cut from the RBA next year.

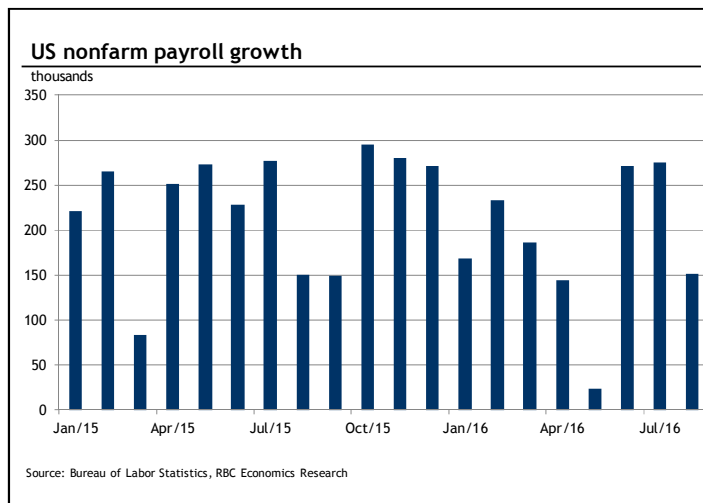
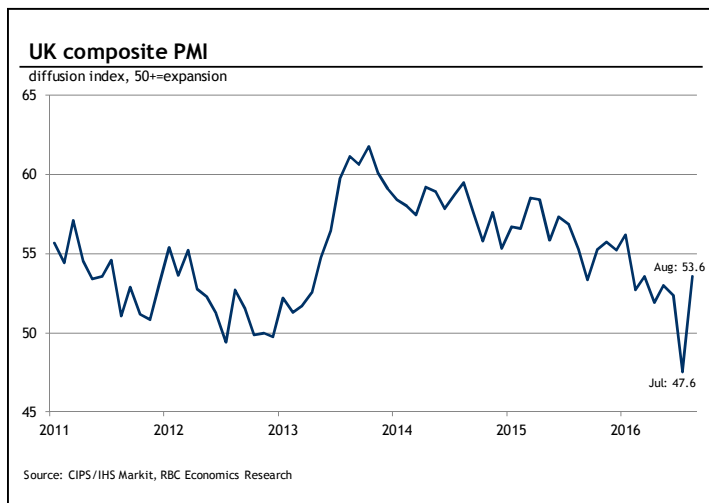
The RBNZ maintained a strong easing bias after lowering the cash rate in August, with its projections showing another 25-50 basis points of easing anticipated. We look for the central bank to follow up with another rate cut in September.



Signal and noise

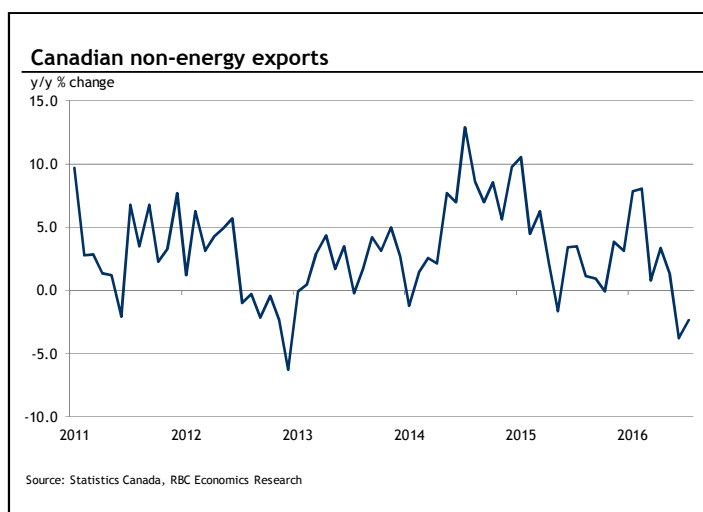
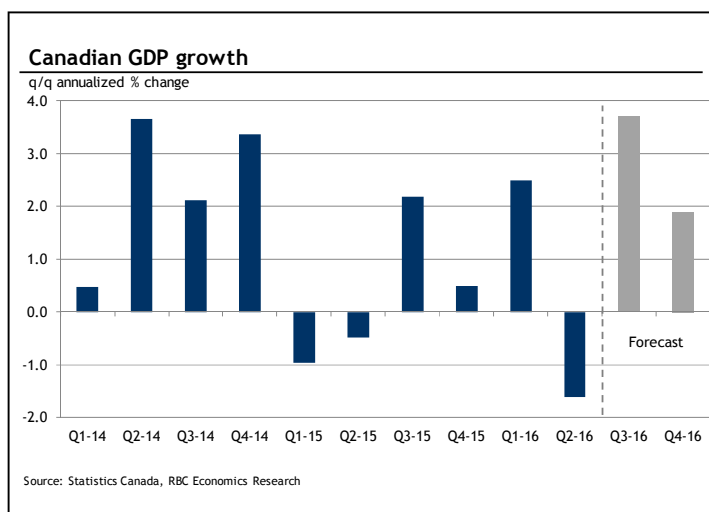
The UK's composite PMI fully recovered in August after a substantial decline in July. Looking through the volatility, we continue to expect the economy will stagnate in H2/16.

A dreadful US payroll report in May gave way to strong job gains in June and July. August fell short of expectations, but the 151,000 increase can hardly be called disappointing.



Shutdowns in the oil sector contributed to a 1.6% annualized decline in Canada's Q2/16 GDP. We look for growth to rebound to 3.7% as oil output returns to normal levels.

Canada's non-energy exports improved in July but are still below year-ago levels following a substantial decline in Q2/16.



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