SCHOOL ENERGY COALITION

CROSS-EXAMINATION MATERIALS

EB-2016-0152

OPG Cost of Capital Witnesses

other post-employment benefit ("OPEB") costs. Based on the above, Concentric's opinion is that the appropriate equity ratio for the Company exceeds the currently deemed ratio of 45% previously set by the Board in the EB-2013-0321 rate proceeding.

In terms of the comparable return requirement of the fair return standard, the range of common equity ratios for comparable utilities is 40.27% to 54.29%, with an average equity ratio of 49.06% and a median of 49.95%. OPG's current equity ratio of 45% is on the low end of the comparable group despite its elevated level of risk relative to the proxy group. Specifically, with its significant nuclear concentration, as well as its status as the only company in the group that is a pure generating company, OPG falls toward the upper end of the risk spectrum. Thus, given OPG's elevated risk relative to the average level of risk faced by the proxy group, Concentric believes the proxy group average and median equity ratios of approximately 49% to 50% provide a floor for the consideration of an appropriate equity ratio for the Company for the 2017-2021 period.

Concentric also finds that an equity ratio of at least 49% will be: (1) more supportive of OPG's financial integrity and access to capital; (2) consistent with the requirements of the fair return standard, and (3) beneficial to customers. Specifically, an increase in OPG's equity ratio from its current 45% to 49% will increase cash flow to the Company, bettering its financial stability and strengthening the metrics that the ratings agencies evaluate when assigning credit ratings. Financial stability and strengthened cash flow benefit all stakeholders of the Company, both by maintaining the financial health of the utility, and by supporting its credit rating.

Lastly, while OPG's risk level is at the upper end of the risk spectrum, Concentric finds that an equity ratio at or above the proxy group average (rather than high end of the range) is appropriate.

In summary, given the material increase in risks since EB-2013-0321, Concentric recommends an equity ratio of no less than 49% be set in the upcoming proceeding, based on the following factors:

- The change in the nuclear to hydroelectric asset mix
- The increase in OPG's business risk driven by the DRP
- Plans to pursue extended Pickering operations beyond 2020 and the aging of the Pickering plant
- The move to IR for hydroelectric rate-setting and to long-term rate-setting periods for nuclear operations
- The recovery risks associated with pension and OPEB costs and revenue deferred under rate smoothing
- OPG's higher risk relative to comparable firms that have a median equity ratio of almost 50%

[redacted]

[redacted]

Key Assumptions and Risks

- Planned activities carried out over the 2017-2020 period successfully enable Pickering continued operations beyond 2020, with a corresponding operating licence granted by the Canadian Nuclear Safety Commission (CNSC) by August 2018. Inability to extend Pickering operations beyond 2020 would result in a reduction to planned generation revenues and cash flow and the advancement of employee severance and station decommissioning expenditures. Extending Pickering operations has a moderating effect on OPG's nuclear rates.
- The Darlington refurbishment is executed consistent with the approved project budget and schedule. Failure to maintain cost and schedule commitments for the project could potentially result in significant write-offs against net income as well as reputational damage. In addition, inability to carry out the refurbishment of the first unit as planned may result in the Province of Ontario (Province) not proceeding with OPG's refurbishment of the remaining units.
- New regulated rates are effective January 1, 2017. An OEB decision that delays this effective date would result in a ~$50 million to $60 million reduction in net income per month. In addition, new rates established by the OEB that are lower than those requested by OPG may not provide for recovery of all costs of OPG's regulated operations or may not allow for an appropriate rate of return.
- Pension and OPEB costs allowed in the 2017-2021 nuclear rates are limited to cash amounts, with the difference between accrual and cash amounts (for nuclear and hydroelectric) continuing to be recorded in a deferral account. The OEB provides necessary assurance over future recovery of these amounts, including associated taxes, through the ongoing generic proceeding on this issue or otherwise. An OEB decision that leads to a write-off of the deferral account balance would result in material net income reductions of over ~$600 million over the planning period.
- Inability to retain and attract leadership talent and qualified management employees during the Darlington refurbishment and continued Pickering operations could adversely impact the successful execution of these projects and other strategic imperatives.
- OPG continues to report its financial results in accordance with United States generally accepted accounting principles (US GAAP) and the OEB continues to rate regulate OPG on that basis. Adoption of International Financial Reporting Standards (IFRS), either as a result of the expiry of the Ontario Securities Commission exemption allowing OPG to prepare its consolidated financial statements using US GAAP or the Shareholder's requirement to consolidate OPG's results under IFRS, is expected to cause significant volatility in OPG's net income compared to US GAAP. Currently, IFRS does not adequately address a rate regulated environment.
- OPG's pension, OPEB and nuclear waste obligations, and related funds are exposed to financial market conditions. The plan assumes that the funds perform according to long-term expectations.

Further details of the key planning assumptions for the 2017-2021 period are found in Appendix 1 and additional key risks to the plan are identified in Appendix 2. A discussion of the 2017-2019 Business Plan, organized by each of OPG's four strategic imperatives, is provided below. The detailed financial and headcount information is included in Appendix 3.

Operational Excellence

OPG remains focused on improving asset reliability, increasing output and safely generating electricity at a low cost. The business plan reflects funding and staffing levels aimed at achieving top performance at the Darlington nuclear station, maximizing the value of the Pickering nuclear station by continuing its safe and reliable operation to 2024, and maintaining strong cost-effective performance at OPG's hydroelectric and thermal facilities. Performance targets for safety and reliability over the planning period will continue to drive operational excellence.

APPENDIX 2: KEY RISKS

The key risks associated with the 2017-2019 Business Plan are outlined below.

Operational and Project Risks

- Failure to maintain the Darlington refurbishment cost and schedule commitments per the approved project budget and schedule;
- Inability to meet the objectives of the first unit refurbishment, resulting in sub-optimal post-refurbishment performance;
- Risk of the Province not concurring with the refurbishment of the subsequent Darlington units;
- Inability to retain and attract effective, knowledgeable and engaged leadership talent during the Darlington refurbishment and continued Pickering operations given an aging workforce and Management group compensation constraints;
- Failure to appropriately staff operational and support groups in critical skill areas given ongoing demographic challenges;
- Inability to achieve production targets, including risks associated with unit capability factors, planned nuclear outage performance, nuclear station lifecycle management, and human performance;
- Risk of increased operating costs as a result of greater-than-planned deterioration of station components and systems, discovery of unexpected conditions, and/or equipment failures; and
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020, and/or failure to obtain regulatory assurance from the CNSC in support of the station's continued operations, including inability to renew the operating licence without conditions.

Rate Regulation Risks

OEB rulings impacting OPG's rate regulated operations may be unfavourable compared to assumptions in the plan, including the following:

- Inability to receive sufficient assurance from the OEB for future recovery of the pension and OPEB cash-to-accrual deferral account balance projected at ~$480 million by the end of 2016 with further additions totalling ~$150 million over the 2017-2021 period, and associated taxes, which would result in a write-off against net income;
- An OEB-set nuclear rate smoothing trajectory that does not provide sufficient cash flow to fund operations, projects and/or obligations, and/or to maintain the current investment grade credit rating. A credit rating downgrade would increase borrowing costs and could reduce borrowing capacity;
- OEB-approved revenue requirements that do not allow for recovery of the full costs of the regulated operations and/or do not allow the regulated business to earn an appropriate return; and
- An effective date for new regulated rates that is later than the assumed January 1, 2017 date, which would reduce 2017 planned net income by ~$50 to $60 million per month.

Financial Risks

- Risk of delay in the Province's approval of the 2017 ONFA Reference Plan to 2017, which could result in a reduction in 2017 planned nuclear segregated fund earnings, through a reduction limiting fund asset balance sheet values to the updated, lower ONFA funding obligations. The impact of this reduction is currently reflected in the 2016 forecast net income on the assumption that the new reference plan is approved by the end of 2016.
- Risk of lower than planned returns on segregated nuclear and pension fund assets as a result of various market factors, including equity prices, interest rates, inflation, and commodity prices, which would lower net income and potentially increase future funding requirements compared to the plan;
- Risk of lower discount rates and other differences in assumptions for future pension and OPEB accounting and funding valuations, compared to the plan, including those due to underlying financial market conditions; and
- Risk of adoption of IFRS for financial reporting purposes, either as a result of the expiry of the Ontario Securities Commission exemption allowing OPG to prepare its consolidated financial statements under US GAAP or the Shareholder's requirement to consolidate OPG's results using IFRS. Adoption of IFRS is expected to cause significant net income volatility compared to US GAAP.

The New York Times | https://nyti.ms/2owRKs2

ENERGY & ENVIRONMENT

Westinghouse Files for Bankruptcy, in Blow to Nuclear Power

By DIANE CARDWELL and JONATHAN SOBLE MARCH 29, 2017

Westinghouse Electric Company, which helped drive the development of nuclear energy and the electric grid itself, filed for bankruptcy protection on Wednesday, casting a shadow over the global nuclear industry.

The filing comes as the company's corporate parent, Toshiba of Japan, scrambles to stanch huge losses stemming from Westinghouse's troubled nuclear construction projects in the American South. Now, the future of those projects, which once seemed to be on the leading edge of a renaissance for nuclear energy, is in doubt.

"This is a fairly big and consequential deal," said Richard Nephew, a senior research scholar at the Center on Global Energy Policy at Columbia University. "You've had some power companies and big utilities run into financial trouble, but this kind of thing hasn't happened."

Westinghouse, a once-proud name that in years past symbolized America's supremacy in nuclear power, now illustrates its problems.

Many of the company's injuries are self-inflicted, such as a disastrous deal for a construction business that was intended to control costs and instead precipitated the events that led to the filing on Wednesday. Over all, Toshiba has been widely criticized for overpaying for Westinghouse.

But some of what went wrong was beyond either company's control. Slowing demand for electricity and tumbling prices for natural gas have eroded the economic rationale for nuclear power, which is extremely costly and technically challenging to develop. Alternative-energy sources like wind and solar power are rapidly maturing and coming down in price. The 2011 earthquake in Japan that led to the nuclear disaster at the Fukushima Daiichi plant renewed worries about safety.

Westinghouse's problems are already reducing Japan's footprint in nuclear power, an industry it has nurtured for decades in the name of energy security. Even before the filing, Toshiba had essentially retired Westinghouse from the business of building nuclear power plants. Executives said they would instead focus on maintaining existing reactors — a more stable and reliably profitable business — and developing reactor designs.

That has made the already small club of companies that take on the giant, expensive and complex task of nuclear-reactor building even smaller. General Electric, a pioneer in the field, has scaled back its nuclear operations, expressing doubt about their economic viability. Areva, the French builder, is mired in losses and undergoing a large-scale restructuring.

Among the winners could be China, which has ambitions to turn its growing nuclear technical abilities into a major export. That has raised security concerns in some countries.

The shrinking field is a challenge for the future of nuclear power, and for Toshiba's revival plans. Its executives have said they would like to sell all or part of Westinghouse to a competitor, but with a dwindling list of potential buyers — combined with Westinghouse's history of financial calamity — that has become a difficult task.

Toshiba still faces tough questions. The company is also divesting its profitable semiconductor business and plans to sell a stake to an outside investor to raise capital. Most of the companies seen as possible buyers are from outside Japan. Some

Japanese business leaders have expressed fears that the sale will further erode Japan's place in an industry it once dominated.

After writing down Westinghouse's value, Toshiba said it expected to book a net loss of $9.9 billion for its current fiscal year, which ends on Friday.

"We have all but completely pulled out of the nuclear business overseas," Toshiba's president, Satoshi Tsunakawa, said at a news conference. Of the huge loss, he added, "I feel great responsibility."

Bankruptcy will make it harder for Westinghouse's business partners to collect money they are owed by the nuclear-plant maker. That mostly affects the American power companies for whom it is building reactors, analysts say. Now, it is unclear whether the company will be able to complete any of its projects, which in the United States are about three years late and billions over budget.

The power companies — Scana Energy in South Carolina and a consortium in Georgia led by Georgia Power, a unit of Southern Company — would face the possibility of new contract terms, long lawsuits and absorbing losses that Toshiba and Westinghouse could not cover, analysts say. The cost estimates are already running $1 billion to $1.3 billion higher than originally expected, according to a recent report from Morgan Stanley, and could eventually exceed $8 billion over all.

Dennis Pidherny, a managing director at Fitch Ratings who is sector head of the United States public power group, said that it was possible that the company's bankruptcy filing could terminate the contracts and that it could be difficult for the utilities to find another builder to take them over.

"There's still quite a bit of work that needs to be completed," he said. "The biggest challenge there is quite simply finding another suitable contractor who can complete the contract and have it completed at a quote-unquote reasonable cost."

That is, if they are constructed at all. Stan Wise, chairman of the Georgia Public Service Commission, said the utilities developing the Alvin W. Vogtle generating station in the state would have to evaluate whether it made sense to continue.

"It's a very serious issue for us and for the companies involved," Mr. Wise said.

"If, in fact, the company comes back to the commission asking for recertification, and at what cost, clearly the commission evaluates that versus natural gas or renewables."

In a statement on Wednesday, Toshiba said Westinghouse and affiliated companies were "working cooperatively" with the owners to arrange for construction to continue. In recent days, the affected companies issued statements saying they were monitoring the situation and exploring their options, as did the Energy Department, which has authorized $8.3 billion in federal loan guarantees for the Georgia project.

"We are keenly interested in the bankruptcy proceedings and what they mean for taxpayers and the nation," said Lindsey Geisler, a Department of Energy spokeswoman. "Our position with all parties has been consistent and clear: We expect the parties to honor their commitments and reach an agreement that protects taxpayers, promotes economic growth, and strengthens our energy and national security."

Toshiba said Westinghouse had total debt of $9.8 billion. The Chapter 11 bankruptcy filing was made in federal bankruptcy court for the Southern District of New York.

A decade ago, Toshiba was dreaming of a big global expansion when it bought Westinghouse for a surprisingly high $5.4 billion and made plans to install 45 new reactors worldwide by 2030.

At the same time, Westinghouse was trying to install a novel reactor design, the AP1000. Using simplified structures and safety equipment, it was intended to be easier and less expensive to install, operate and maintain. Its design also improves the ability to withstand earthquakes and plane crashes and is less vulnerable to a cutoff of electricity, which is what set off the triple meltdown at Fukushima.

Nonetheless, it was inevitable that expansions at the Vogtle generating station in Georgia and the Virgil C. Summer plant in South Carolina would hit some bumps along the road to fruition, nuclear executives say. Not only was the design new, but, because nuclear construction had been dormant for so long, American companies also lacked the equipment and expertise needed to make some of the biggest components and construct the projects.

Indeed, that may ultimately have been at the root of the troubles. The contractor Westinghouse chose to complete the projects struggled to meet the strict demands of nuclear construction and was undergoing its own internal difficulties after a merger. As part of an effort to get the delays and escalating costs under control, Westinghouse acquired part of the construction company, which set off a series of still-unresolved disputes over who should absorb the cost overruns and how Westinghouse accounted for and reported values in the transaction.

In its bankruptcy filing, Westinghouse said that its top 30 unsecured creditors held over $508 million in claims. Among those creditors are big engineering and construction companies like Fluor and CB&I, and Nuclear Fuel Services, a fuel supplier.

To shepherd its case through Chapter 11, Westinghouse has hired a number of advisers, including the investment bank PJT Partners, the law firm Weil, Gotshal & Manges, and the consulting firm AlixPartners.

Westinghouse also said in its bankruptcy filing that it had taken out an $800 million loan from a group led by Citigroup to support itself through the bankruptcy process.

Diane Cardwell reported from New York, and Jonathan Soble from Tokyo. Michael J. de la Merced contributed reporting from New Orleans.

Rating Report

Ontario Power Generation Inc.

DBRS

Insight beyond the rating.

Tom Li
+1 416 597 7378
tli@dbrs.com

James Jung, CFA, FRM, CPA, CMA
+1 416 597 7577
jjung@dbrs.com

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.

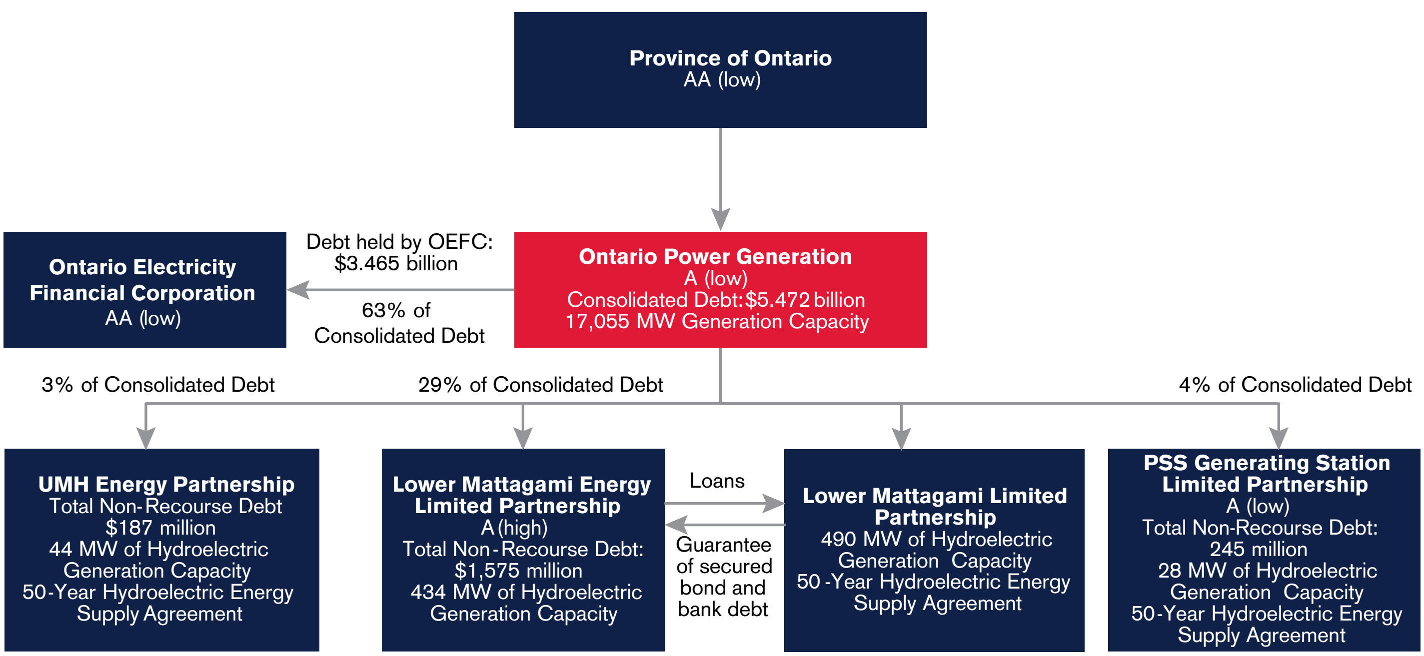
Major Projects

- **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

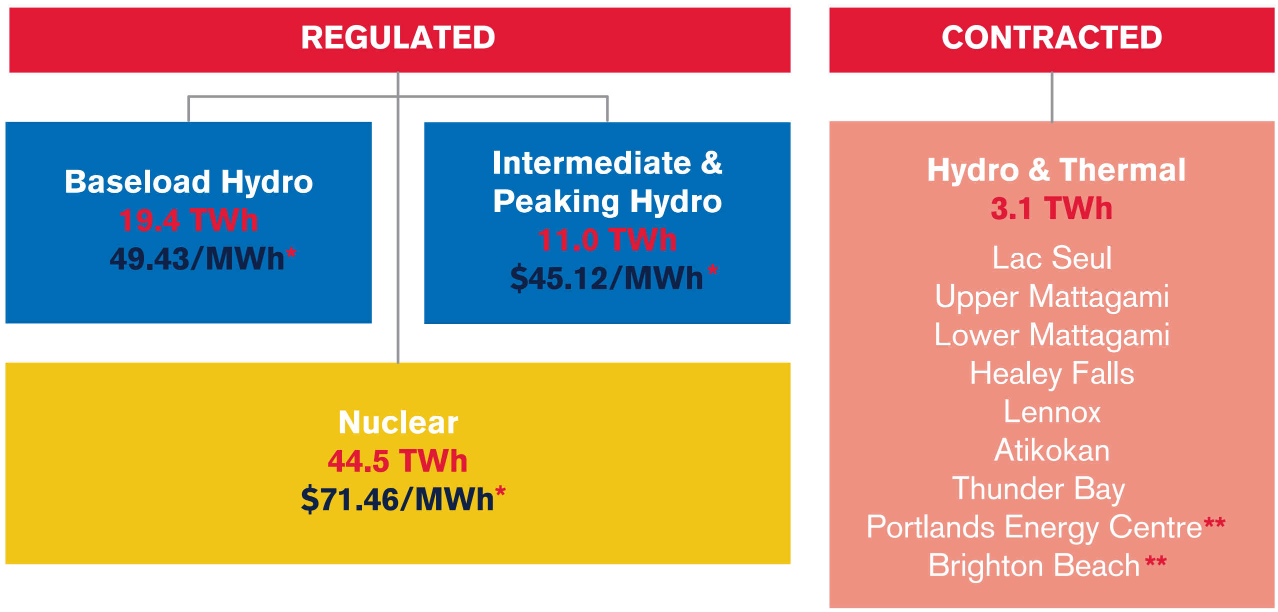


As of December 31, 2015.

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.

Research

Research Update:

Ontario Power Generation Inc. Rating Lowered To 'BBB+' From 'A-' On Province of Ontario Downgrade; Outlook Stable

Primary Credit Analyst:
Stephen R Goltz, Toronto (416) 507-2592; stephen.goltz@standardandpoors.com

Secondary Contact:
Andrew Ng, Toronto (416) 507-2545; andrew.ng@standardandpoors.com

Table Of Contents

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

Filed: 2016-10-26
EB-2016-0152
Exhibit L, Tab 3.1
Schedule 20 VECC-008
Attachment 2
Page 4 of 6

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
Page 5 of 6

- 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)	

Complete ratings information is available to subscribers of RatingsDirect at www.globalcreditportal.com and at www.spcapitaliq.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

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%

	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]
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.

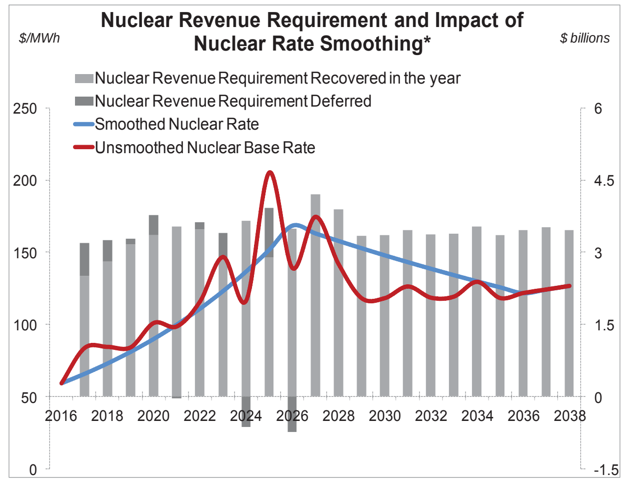
Exhibit 2: Proxy Group Company Relevant Indicators

Parent Company Ticker	Operating Company	State or Province	Weighted Common Equity/Total Cap (%)	S&P Credit Rating	Operating Revenue: Electric
ALE	ALLETE (Minnesota Power)	MN	54.29		
ALE [1]			54.29	BBB+	$1,013,221
AEE	Union Electric Company	MO	51.76		
AEE	Ameren Illinois Company	IL	50.00		
AEE [1]			50.87	BBB+	$4,953,315
AEP	Columbus Southern Power Company	OH	50.64		
AEP	Ohio Power Company	OH	53.79		
AEP	Appalachian Power Company	WV	47.16		
AEP	Indiana Michigan Power Company	IN	42.67		
AEP	Appalachian Power Company	VA	42.89		
AEP	Indiana Michigan Power Company	MI	42.07		
AEP	Southwestern Electric Power Company	AR	33.99		
AEP	AEP Texas Central Company	TX	40.00		
AEP	AEP Texas North Company	TX	40.00		
AEP	Southwestern Electric Power Company	TX	49.10		
AEP [1]			45.77	BBB	$14,490,000
DUK	Duke Energy Ohio, Inc.	OH	53.30		

Parent Company Ticker	Operating Company	State or Province	Weighted Common Equity/Total Cap (%)	S&P Credit Rating	Operating Revenue: Electric
DUK	Duke Energy Indiana, LLC	IN	44.44		
DUK	Duke Energy Florida, LLC	FL	45.74		
DUK	Duke Energy Carolinas, LLC	SC	53.00		
DUK	Duke Energy Progress, LLC	SC	44.72		
DUK	Duke Energy Progress, LLC	NC	53.00		
DUK	Duke Energy Carolinas, LLC	NC	53.00		
DUK [1]			50.14	A-	$22,581,161
EIX	Southern California Edison Company	CA	48.00		
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		
EMA	Emera Maine	ME	49.00		
EMA	Nova Scotia Power Inc.	Nova Scotia	37.50		
EMA [1]			40.27	BBB+	$2,067,200
ETR	Entergy Arkansas, Inc. [3]	AR	46.27		
ETR [1]			46.27	BBB	$10,904,103
FE	Cleveland Electric Illuminating Company	OH	49.00		
FE	Ohio Edison Company	OH	49.00		

Parent Company Ticker	Operating Company	State or Province	Weighted Common Equity/Total Cap (%)	S&P Credit Rating	Operating Revenue: Electric
FE	Toledo Edison Company	OH	49.00		
FE	Potomac Edison Company	WV	46.42		
FE	Jersey Central Power & Light Company	NJ	50.00		
FE [1]			49.22	BBB-	$9,871,000
FTS	Central Hudson Gas & Electric Corporation	NY	48.00		
FTS	Tucson Electric Power Company	AZ	43.50		
FTS	UNS Electric, Inc.	AZ	52.60		
FTS	Fortis BC Electric	British Columbia	40.00		
FTS	Fortis Alberta	Alberta	40.00		
FTS	Newfoundland Power	Newfoundland & Labrador	45.00		
FTS	Maritime Electric	Prince Edward Island	40.00		
FTS	Fortis Ontario	Ontario	40.00		
FTS [1]			43.31	A-	$3,554,612
GXP	KCP&L Greater Missouri Operations Company	MO	52.30		
GXP	Kansas City Power & Light Company	MO	50.09		
GXP	Kansas City Power & Light Company	KS	50.48		
GXP Weighted Average [1]			51.04	BBB+	$2,568,200
IDA	Idaho Power Co.	OR	49.90		

For the nuclear operations, consistent with *Ontario Regulation 53/05*, the rate application includes OPG's 11% per year rate smoothing proposal that avoids large price spikes arising during the Darlington refurbishment and at the end of Pickering operations. Under rate smoothing, the rate application seeks approval of annual nuclear revenue requirements as well as a smoothed rate trajectory for the 5-year period. The difference between the approved revenue requirements and the approved base rate trajectory will be recorded in a deferral account for recovery in the post-refurbishment period. The assumed nuclear rate trajectory from the rate application is below the 2013 LTEP assumptions for OPG's nuclear rates.



* Information beyond 2021 is included for illustrative purposes

In accordance with the regulation, the portion of the approved nuclear revenue requirement deferred for future collection will be determined by the OEB and captured in a deferral account that will earn interest at a long-term debt rate reflecting OPG's long-term borrowing cost as authorized by the OEB, compounded annually. Pursuant to the regulation, the OEB must authorize the recovery of the account balance over a period of up to 10 years beginning at the end of the refurbishment project. The rate smoothing illustration shown assumes recovery of the deferred balance over the 10-year period following the completion of the Darlington refurbishment. Based on the assumed rate trajectory, the deferral account balance, including associated interest, is projected to grow to ~$1.3 billion by 2019 and ~$1.9 billion by 2021. In accordance with US GAAP, rate smoothing deferrals in a given period will be recorded by OPG as income of that period, with the deferral account recorded as a regulatory asset on the balance sheet. Accordingly, the collection of the deferred amounts in future years will not result in additional net income.

Although for planning purposes OPG assumes smoothed nuclear base rate increases of 11% per year for the full Darlington refurbishment period, the determination of the rate trajectory beyond 2021 is not part of OPG's current rate application and will be established by the OEB in the future. Leading up to that period, OPG will continue to focus on improving its cost structure and generation performance.

Ontario Nuclear Funds Agreement Reference Plan Update

The plan reflects estimated impacts from the 2017 ONFA Reference Plan, assumed to be approved by the Minister of Finance by the end of 2016. The impacts over the planning period include the elimination of ~$180 million per year in OPG's contributions to the ONFA segregated funds, due to lower funding obligations for nuclear decommissioning and waste management. The impacts also include a decrease of ~$1.5 billion in OPG's present value accounting liability for these obligations, at the end of 2016. The main driver of the reduced obligations is lower costs associated with the long-term management of used nuclear fuel as estimated by the Nuclear Waste Management Organization. The lower costs are primarily due to a combination of a more cost effective used fuel disposal container and a delay in the assumed construction of the used fuel deep geologic repository as part of the Adaptive Phase Management plan. OPG's decommissioning and waste management obligations include those for the stations leased to Bruce Power.

The reduction in segregated fund contributions reflects the expectation that both the Decommissioning Segregated Fund and the Used Fuel Segregated Fund will be fully funded when the new ONFA Reference Plan with lower obligations is approved by the Province. This change improves OPG's operating cash flow but will not impact earnings, as the contributions are not treated as operating expenses. The reduction in the accounting liability lowers future depreciation, accretion and other related expenses; however, the majority of this impact does not affect net income as it will reduce amounts recovered through regulated rates. Upon approval of the new ONFA Reference Plan, OPG expects to file an update to its May 2016 rate application to reflect the lower costs to the benefit of customers.

Financing and Liquidity

With the exception of 2017, OPG's operating cash flow outlook is forecast [redacted]. In 2017, operating cash flow is expected to

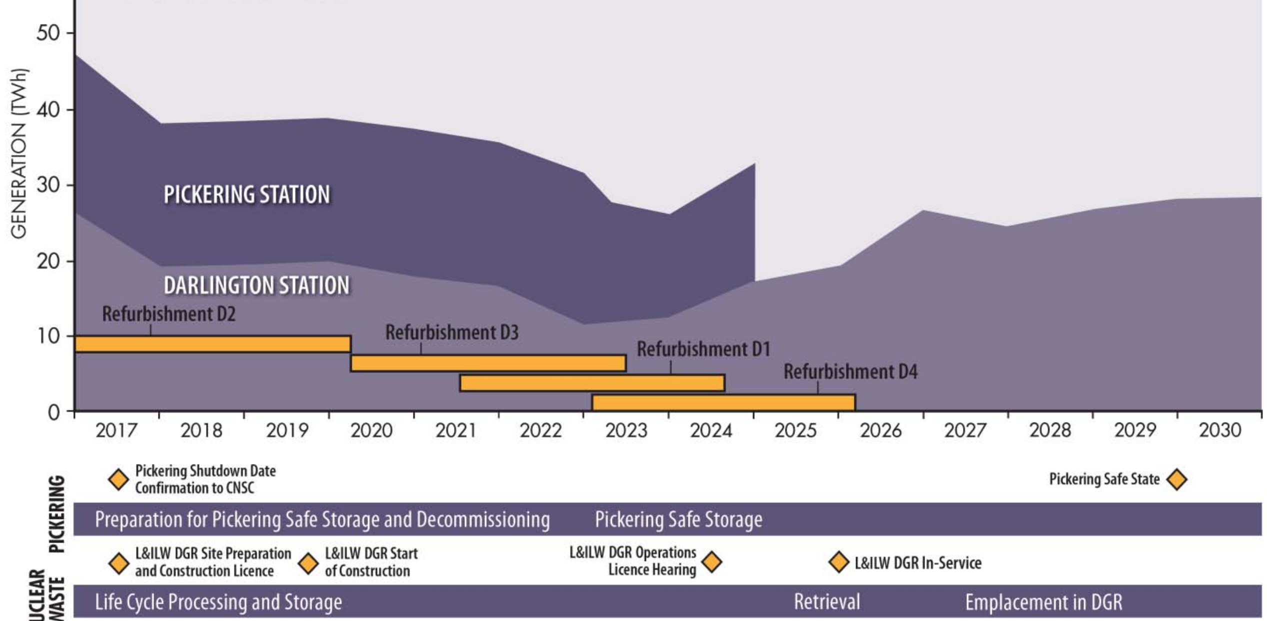
APPENDIX 5: NUCLEAR STRATEGIC FRAMEWORK

Nuclear Strategic Framework

Nuclear Cornerstones of Excellence

• Safety • Reliability • Value for Money • Human Performance

- Extending the life of Pickering station to 2024
- Achieving the cost and schedule commitments for the Darlington Refurbishment Project
- Safely and responsibly managing Ontario's nuclear waste
- Establish an organization that positions Darlington to achieve Top Quartile operational and financial performance
- Execute Pickering SAFSTOR project and transition to decommissioning



Key Strategic Goals

2017–2019

OPERATIONAL EXCELLENCE

- Protecting the health and safety of workers, public, environment, and plant.
- Establishing an Equipment Reliability Centre of Excellence to support sustainable reliability of our Nuclear stations.

PROJECT EXCELLENCE

- Integrating and executing the Darlington Unit 2 Refurbishment on schedule and budget.
- Improving project outcomes across the enterprise through the Project Management Centre of Excellence.

FINANCIAL STRENGTH

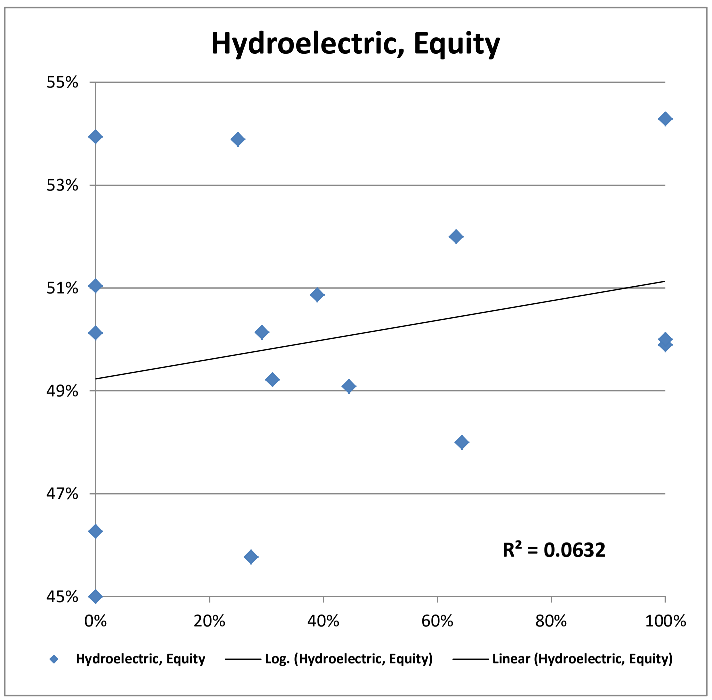
- Focusing on outage performance to meet our generation commitments.
- Optimizing inventory levels while ensuring availability of critical parts.
- Completing assessments to enable extending Pickering operations to 2024.

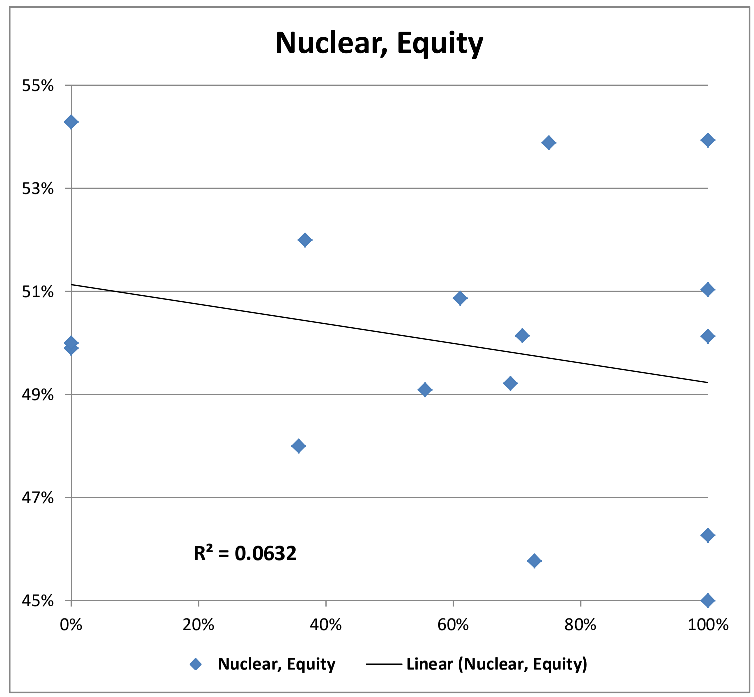
SOCIAL LICENCE

- Complying with all applicable laws, codes, and regulations.
- Ensuring safety of the public and environment and reducing tritium emissions as low as reasonably achievable.
- Strong community and stakeholder relations.

Relationship of Generation Type to Equity Thickness - U.S. Peer Group Utilities

Utility	Symbol	Nuclear		Hydroelectric		Equity
		% Total	% Gen	% Total	% Gen	
PNM Resources	PNM	17%	100%	0%	0%	45.00%
American Electric	AEP	8%	73%	3%	27%	45.77%
Entergy	ETR	15%	100%	0%	0%	46.27%
Edison	EIX	20%	36%	36%	64%	48.00%
Southern Company	SO	10%	56%	8%	44%	49.09%
FirstEnergy	FE	40%	69%	18%	31%	49.22%
IDACORP	IDA	0%	0%	52%	100%	49.90%
Portland General	POR	0%	0%	14%	100%	50.00%
Westar Energy	WR	9%	100%	0%	0%	50.13%
Duke	DUK	17%	71%	7%	29%	50.14%
Ameren	AEE	11%	61%	7%	39%	50.87%
Great Plains	GXP	8%	100%	0%	0%	51.04%
PG&E	PCG	29%	37%	50%	63%	52.00%
Xcel Energy	XEL	9%	75%	3%	25%	53.89%
Pinnacle West	PNW	18%	100%	0%	0%	53.94%
Allete, Inc.	ALE	0%	0%	6%	100%	54.29%





CONCENTRIC ENERGY ADVISORS

Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities

Volume III, May 1, 2015

INTRODUCTION

Concentric Energy Advisors, Inc. (Concentric) is pleased to publish the third edition of this newsletter summarizing authorized returns on common equity (ROEs) and common equity ratios for Canadian gas and electric distributors, Canadian electric transmission companies, U.S. gas and electric distributors, and select bond yields. Many regulators, stakeholders and analysts in Canada consider allowed returns in other Canadian jurisdictions and U.S. utilities when assessing the cost of capital. This newsletter seeks to assist with these inter-jurisdictional comparisons.

This newsletter and supporting database contain the authorized ROEs and common equity ratios for over 40 Canadian electric and gas utilities. For comparison purposes, the newsletter also presents the average and median authorized ROEs and common equity ratios for U.S. gas and electric distributors, as reported by SNL Financial's Regulatory Research Associates.

ROE

Concentric observes that the differential between the median authorized ROEs for Canadian and U.S. gas distributors continues to narrow, from 100 basis points in 2000 to 53 basis points in 2014 and to only 18 basis points through the first three months of 2015. There is a larger gap between Canadian and U.S. electric distributors, at 125 basis points in 2014 and 122 basis points in 2015. Concentric notes that gas ROEs are higher than their electric counterparts in Canada, while the opposite is generally true in the U.S. Median ROEs for Canadian electric transmission companies are 20 basis points lower than those awarded to Canadian electric distributors, but 142–145 basis points below U.S. electric distributors over the 2014–2015 period.

Concentric attributes the closure of the gap between Canadian and U.S. authorized ROEs over the past decade to the resetting and replacement of automatic formulas widely used in Canada, which has generally increased allowed ROEs from previous formula levels. Simultaneously, U.S. ROEs have followed the decline in interest rates and earnings growth projections that drive ROE estimates.

EQUITY RATIOS

While authorized ROEs have converged between the two countries, the authorized common equity ratios have not. In 2014, the median common equity ratio for Canadian gas distributors was 39.3% while the U.S. median was 51.9%, comparable to the difference for electric distributors which was 40.0% and 50.1%, respectively. Allowed equity ratios for Canadian electric transmission companies are 4.0% lower than their electric distribution counterparts, and 14.0% below U.S. electric distributors.

RECENT DECISIONS

Canadian utility regulators have issued several important cost of capital decisions since the second edition of this newsletter was published in May 2014. Notably, in Alberta, the Alberta Utilities Commission recently issued its decision in the 2013 Generic Cost of Capital proceeding for all gas and electric utilities in the Province. The allowed ROE for Alberta's gas and electric utilities was set at 8.3% for 2015. In addition, the AUC determined that the allowed ROE for 2013 and 2014 would be modified from the previous interim rate of 8.75% to 8.3%. The AUC also reduced the deemed common equity ratio by one percentage point for most Alberta regulated utilities and decided to forego returning to an automatic formula at this time. The Alberta utilities have filed applications to appeal this decision.

In Ontario, the Ontario Energy Board's revised ROE formula established in December 1999 remains in effect but is scheduled to be reviewed in 2015. In Québec, the Régie again decided to allow Gaz Métro to maintain its allowed ROE of 8.9% without a formal proceeding, and similarly for Hydro-Québec Distribution and TransÉnergie, maintaining 8.2% for both divisions.

BOND YIELDS

Government and corporate bond yields are often considered when setting authorized ROEs for utilities. As shown in the chart on page 3, after declining for many years, the long-term government bond yields (considered the risk-free rate of return) in both Canada and the U.S. increased from mid-2012 through mid-2013, but have since resumed their prolonged decline. While government bond yields play an important role in determining the authorized ROE for regulated utilities, changes in government bond yields do not imply a one-for-one change in the cost of equity for utilities. The relationship between government bond yields and the equity risk premium (the spread between government bond yields and the cost of equity) has historically exhibited an inverse relationship.

Going forward, Concentric anticipates that improving economic conditions and the withdrawal of accommodative monetary policy in both Canada and the U.S. will begin to exert upward pressure on the cost of capital for utilities over the next several years.

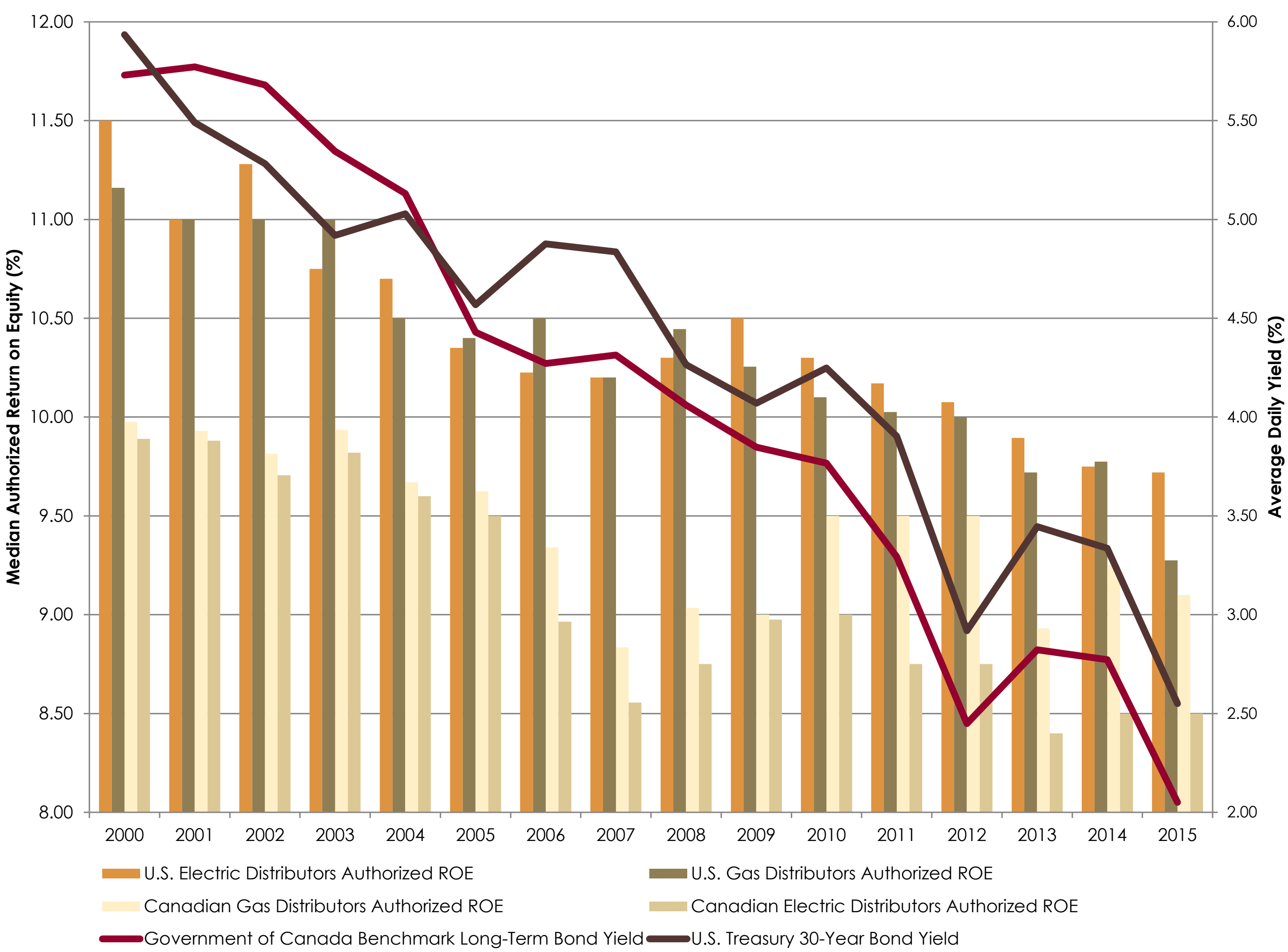
CONCENTRIC ENERGY ADVISORS

Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities [1]

	Return on Common Equity (%)			Common Equity Ratio (%)		
	2013	2014	2015	2013	2014	2015
Canadian Gas Distributors [2]						
AltaGas Utilities Inc. [3]	8.30	8.30	8.30	42.00	42.00	42.00
ATCO Gas [3]	8.30	8.30	8.30	38.00	38.00	38.00
Centra Gas Manitoba Inc.	N/A	N/A	N/A	30.00	30.00	30.00
Enbridge Gas Distribution Inc. [4]	8.93	9.36	9.30	36.00	36.00	36.00
Enbridge Gas New Brunswick	10.90	10.90	10.90	45.00	45.00	45.00
FortisBC Energy Inc.	8.75	8.75	8.75	38.50	38.50	38.50
FortisBC Energy (Vancouver Island) Inc. [5]	9.25	9.25	—	41.50	41.50	—
FortisBC Energy (Whistler) Inc. [5]	9.50	9.50	—	41.50	41.50	—
Gaz Métro Limited Partnership	8.90	8.90	8.90	38.50	38.50	38.50
Gazifère Inc.	7.82	9.10	9.10	40.00	40.00	40.00
Heritage Gas Limited	11.00	11.00	11.00	45.00	45.00	45.00
Pacific Northern Gas Ltd.	9.50	9.50	9.50	46.50	46.50	46.50
Pacific Northern Gas (N.E.) Ltd. (Fort St. John/Dawson Creek)	9.25	9.25	9.25	41.00	41.00	41.00
Pacific Northern Gas (N.E.) Ltd. (Tumbler Ridge)	9.50	9.50	9.50	46.50	46.50	46.50
SaskEnergy Inc.	8.75	8.75	7.74	37.00	37.00	37.00
Union Gas Limited [6]	8.93	8.93	8.93	36.00	36.00	36.00
Average	9.17	9.29	9.19	40.19	40.19	40.00
Median	8.93	9.25	9.10	40.50	40.50	39.25
U.S. Gas Distributors [7]						
Average of all Rate Cases Decided in the Year	9.68	9.78	9.48	50.60	51.25	50.60
Median of all Rate Cases Decided in the Year	9.72	9.78	9.28	50.38	51.90	50.48
Canadian Electric Distributors [2]						
ATCO Electric Ltd. [3]	8.30	8.30	8.30	38.00	38.00	38.00
ENMAX Power Corporation [3]	8.30	8.30	8.30	40.00	40.00	40.00
EPCOR Distribution Inc. [3]	8.30	8.30	8.30	40.00	40.00	40.00
FortisAlberta Inc. [3]	8.30	8.30	8.30	40.00	40.00	40.00
FortisBC Inc.	9.15	9.15	9.15	40.00	40.00	40.00
Hydro-Québec Distribution	6.19	8.20	8.20	35.00	35.00	35.00
Manitoba Hydro	* N/A	N/A	N/A	25.00	25.00	25.00
Maritime Electric Company Limited	9.75	9.75	9.75	43.50	43.10	41.90
Newfoundland and Labrador Hydro [8]	4.47	Pending	Pending	20.00	Pending	Pending
Newfoundland Power Inc.	8.80	8.80	8.80	45.00	45.00	45.00
Nova Scotia Power Inc.	9.00	9.00	9.00	37.50	37.50	37.50
Ontario's Electric Distributors [4]	8.98	9.36	9.30	40.00	40.00	40.00
Saskatchewan Power Corporation	8.50	8.50	8.50	40.00	40.00	40.00
Average	8.17	8.72	8.72	37.23	38.63	38.53
Median	8.40	8.50	8.50	40.00	40.00	40.00
U.S. Electric Distributors [7]						
Average of all Rate Cases Decided in the Year	10.02	9.75	9.66	49.25	50.57	51.81
Median of all Rate Cases Decided in the Year	9.90	9.75	9.72	50.84	50.14	51.43

Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities	Return on Common Equity (%)			Common Equity Ratio (%)		
	2013	2014	2015	2013	2014	2015
Canadian Electric Transmission Companies [2]						
AltaLink Management Ltd. [3]	8.30	8.30	8.30	36.00	36.00	36.00
ATCO Electric Ltd. [3]	8.30	8.30	8.30	36.00	36.00	36.00
ENMAX Power Corporation [3]	8.30	8.30	8.30	36.00	36.00	36.00
EPCOR Transmission Inc. [3]	8.30	8.30	8.30	36.00	36.00	36.00
Hydro One Networks Inc.	8.93	9.36	9.30	40.00	40.00	40.00
Hydro-Québec TransÉnergie	6.41	8.20	8.20	30.00	30.00	30.00
Average	8.09	8.46	8.45	35.67	35.67	35.67
Median	8.30	8.30	8.30	36.00	36.00	36.00

Economic Indicators (% Yields) [9]	2013	2014	2015
Government of Canada Benchmark Long-Term Bond Yield	2.82	2.77	2.05
U.S. Treasury 30-Year Bond Yield	3.45	3.34	2.55
Bloomberg Fair Value Canada A-rated Utility Bond Yield	4.24	4.14	3.50
Moody's A-rated Utility Bond Index (U.S.)	4.48	4.27	3.67



CONCENTRIC ENERGY ADVISORS

NOTES

1. Data for an expanded group of Canadian gas transmission companies is contained in the Concentric Energy Advisors Return on Equity Database.
2. Allowed in rates for the corresponding year; where the year overlaps, the rate/ratio shown prevails for the majority of the year. Sources: Regulatory decisions and documents; annual information forms; annual reports.
3. The Alberta Utilities Commission's 2015 decision in the Generic Cost of Capital proceeding was retroactive. Returns on common equity and common equity ratios were adjusted for 2013–2015. This also affects the category averages for 2013–2015 as compared to those reported in previous years.
4. Beginning in 2014, the Ontario Energy Board updates cost of capital parameters for setting rates in cost of service applications only once per year.
5. FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. were amalgamated with FortisBC Energy Inc. and are no longer separate entities in 2015.
6. Union's ROE per settlement agreement in its five-year incentive regulation plan for 2014–2018.
7. Source: SNL Financial LC's Regulatory Research Associates Division. Data for 2015 includes decisions through March 31, 2015.
8. Newfoundland and Labrador Hydro (NLH) filed a General Rate Application (GRA) on July 30, 2013. A decision has not yet been issued on that GRA. The Company subsequently filed a request for interim rates that was denied by the Board in Order No. P.U. 39 (2014), issued September 17, 2014. On November 10, 2014, NLH filed an amended 2013 GRA based on changes to the previous 2014 test year and a new forecasted 2015 test year. That amended GRA remains pending before the Board.
9. Average daily yield. Source: Bloomberg Finance L.P. Data for 2015 through March 31, 2015.

* N/A indicates the data are not available.

CONCENTRIC ENERGY ADVISORS, INC.

For more information regarding this data, please contact:

Jim Coyne
Senior Vice President
jcoyne@ceadvisors.com
508.263.6255
www.ceadvisors.com

John Trogonoski
Senior Project Manager
jtrogonoski@ceadvisors.com
508.263.6258
www.ceadvisors.com