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April 24, 2008

Board Secretary
Ontario Energy Board
2300 Yonge Street, Ste. 2701
Toronto ON M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Board Staff Evidence - Board File # EB-2007-0905
Payment Amounts for OPG's Prescribed Facilities

Attached please find the evidence of London Economics International (LEI) with respect to cost of capital issues in this proceeding.

Please distribute to all Intervenors, Observors and Participants in this case.

Yours truly,

Original signed by

Allan Fogwill
Director - Applications

Encl.

Development of an Overall Framework to Determine an Appropriate Capital Structure and Return on Equity for Ontario Power Generation's Prescribed Facilities

prepared for Ontario Energy Board staff by London Economics International LLC

April 21st, 2008

London Economics International LLC (LEI) was asked to develop an overall framework which can be used to evaluate the risk to equity and an appropriate capital structure for Ontario Power Generation's (OPG) prescribed assets, relative to other power sector assets for which capital structures and returns on equity have been determined or can be observed. The prescribed assets can generally be considered to be low risk, particularly given their current regulatory treatment. Nonetheless, they are not risk free. A regulated return on equity of 5% is lower than that allowed for any of the entities considered in this report which have an equity base. While both higher allowed returns on equity and higher deemed levels of debt can be observed, ultimately any determination of the appropriate parameters for the prescribed assets must take into account the impact of the proposed regulatory arrangements on earnings volatility.

Overall, it is our view that application of a framework for the assessment of overall risks for generation assets would generally show that the volatility of earnings to generation assets exceeds that of regulated wires assets, even where such generation assets are baseload in nature and protected with variance and deferral accounts. While the appropriate additional risk premium for regulated generation assets relative to regulated wires assets may be small, it can only be eliminated if regulatory arrangements fully compensate for volume risk in a more favorable fashion than is available to wires assets. Were the variance and deferral accounts to be eliminated, the risk premium for regulated generation assets relative to wires assets would rise.

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1 Introduction

1.1 scope of work

For the purposes of this engagement, London Economics International LLC (LEI) was asked by Ontario Energy Board (OEB) staff to perform three tasks:

- first, to provide an assessment of the salient risk factors which need to be accounted for in the determination of an appropriate return on equity (ROE) and capital structure for Ontario Power Generation (OPG's) prescribed assets;
- second, to discuss where various power sector and non-power sector entities would appear on a risk continuum based on volatility of returns, and how such volatility may be influenced by regulatory arrangements;
- third, in particular to consider the capital structure and allowed ROEs of a number of Canadian provincially-owned and US Federally-owned power utilities; and
- fourth, develop a framework for determining an appropriate capital structure and return on equity for OPG's prescribed facilities that takes into account the assessed risk factors.

LEI chose to augment this list with a number of other entities, including US generation and transmission co-ops, Canadian generation focused income trusts, US regulated integrated utilities, and US independent power generation companies.

Figure 1. Companies LEI was instructed to consider

Canadian provincial entities	US Federal Power Authorities
BC Hydro	Bonneville Power Administration
Hydro Quebec	Tennessee Valley Authority
Manitoba Hydro	
NBPower	
Newfoundland Power*	
SaskPower	
**privately, rather than provincially, owned*	

LEI was not asked by OEB staff to play the traditional expert role of calculating a specific cost of equity using methods like the capital asset pricing model (CAPM) or a discounted cash flow (DCF) analysis, nor was LEI asked to position the OPG prescribed assets within the framework created by LEI to assess relative risks of various asset classes.

1.2 expert qualifications

LEI and its president A.J. Goulding have been active in the Ontario electricity industry since 1998. During that period LEI has advised a range of clients on issues related to electricity sector asset valuation, public policy, and regulatory affairs. LEI advised on the first lease transaction of a nuclear power station in North America, advised the successful bidder on the privatization of OPG's Mississagi assets, provided expert opinions related to debt and equity financings of Ontario-based hydro assets, and has at various times advised the OEB, the Ontario Power Authority (OPA), and the Independent Electricity System Operator (IESO). Worldwide, the firm has served as a market expert on the acquisition and financing of nuclear and hydro assets collectively approaching one hundred billion US dollars in value, and LEI principals have provided expert testimony before US state regulators, US Federal courts, and Canadian regulatory bodies.

In addition to his extensive work in Ontario, A.J. Goulding teaches at Columbia University's Center for Energy and Marine Transportation in New York. He wrote the Electricity Industry Restructuring Plan for Saudi Arabia, and led an LEI team advising on the successful acquisition by a large Chinese generation company of a Singapore-based generation portfolio. He is also advising private equity clients on the acquisition of small hydro and biomass facilities in the United States.

Additional information on LEI and A.J. Goulding's credentials appears in Appendix C.

1.3 unique nature of cost of service regulation for the assets to be examined

As LEI noted in its previous report to the OEB, "although price regulation of generation is a new activity for the Ontario Energy Board, it has been the norm in a number of jurisdictions outside of Ontario for decades."[1] However, what makes the situation in Ontario unique is that Ontario is the only jurisdiction in North America to impose regulation on generation assets after a competitive[2] wholesale market has been established. As the OEB has pointed out, "OPG is not a natural monopoly supplier of goods and services. There is a market for selling the output from its generation assets, OPG does not have a statutory obligation to serve nor does it have a franchise territory."[3] Given that regulation of generation elsewhere has occurred in a context of regulation of vertically integrated privately-owned monopolies (and, in other provinces, publicly owned vertically integrated monopolies), regulators in North America have yet to face a situation directly analogous to that facing the OEB today.

Although the lack of direct precedence for the situation facing the OEB with regards to the prescribed assets may provide some latitude as to the framework for determining OEB's response, LEI believes several guiding principles should apply:

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[1] London Economics International LLC, "Alternatives for regulating prices associated with output from designated generation assets." Toronto, Ontario, 19th May 2006, p.2.

[2] The Ontario market can only be deemed "competitive" provided provisions are in place to address the potential market power held by OPG; various mechanisms, including the former Market Power Mitigation Agreement (MPMA) and the current arrangements for the prescribed assets, have performed this function.

[3] "Board Report: A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc." Ontario Energy Board, Toronto, Ontario, November 30th, 2006, p.3.

- first, OPG is a corporation created under the *Ontario Business Corporations Act*; in this sense, it is no different from the other entities that the OEB regulates. The Memorandum of Agreement with the province specifically states that "OPG will operate as a commercial enterprise." Although this paper examines many other types of organizations, including US Federal power authorities, co-operatives, and state power authorities, the government of Ontario chose to set OPG up as a standard business corporation. Thus, while the Province is the sole shareholder of OPG, it is unclear why that should impact OEB deliberations any more than if OPG were owned 100% by a private entity – in neither case should OPG be compelled by the regulator to suppress equity returns for the public good, since OPG was established as a "normal" business corporation;

- second, the Ontario Energy Board Act, 1998, Section 78.1, repeatedly uses the terms "just and reasonable" with regards to setting various payment amounts. Canadian tradition defines a "fair" return as that "the company will be allowed as large a return on the capital invested in its enterprise… as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise."[4] This suggests that, when considering the return to allow on the prescribed assets, we should in turn consider which securities would actually be similar to the prescribed assets in terms of "attractiveness", "stability", and "certainty." We will return to these metrics throughout this paper.

- third, the assets themselves are clearly not risk free. Even given the fact that OPG is protected by deferral and variance accounts in ways that its competitors are not, owning and operating nuclear and hydro stations is clearly not the same as clipping coupons on a government bond. At a time when Government of Canada 30 year bonds have in the recent past carried a 5% coupon,[5] a return on equity of 5% for the prescribed assets is clearly inappropriate from a financial market and peer utility context.

Below, we briefly describe the prescribed assets and the current associated financial arrangements, as well as the proposals made by OPG. We also address the intended role of the regulated payments.

1.3.1 description of the prescribed assets

The prescribed assets consist of 9,938 MW of largely baseload generation assets in Ontario. The prescribed asset portfolio contains only hydro and nuclear facilities, and these facilities have been in operation for a number of years. Hydro facilities include some ability to shift production temporally, particularly through the use of pump storage. The table below lists the prescribed assets.

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[4] Supreme Court of Canada, Northwestern Utilities Ltd. v. Edmonton [1929] SCR 186.

[5] Bank of Canada website, www.bankofcanada.ca/en/rates/bond-look.html; refers to benchmark bond yields on the 2037.06.01 issue, with benchmark yield as of January 18th, 2008.

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Figure 2. OPG prescribed assets[6]

Nuclear	MW	Hydroelectric	MW
Pickering A	1,030.0	Niagara Plant Group	
Pickering B	2,064.0	Sir Adam Beck I	447.0
Darlington	3,512.0	Sir Adam Beck II	1,499.2
		Sir Adam Beck Pump	174.0
		DeCew Falls I and II	166.8
		R.H. Saunders	1,045.0
subtotal:	*6,606.0*	*subtotal:*	*3,332.0*
total:	**9,938.0**	MW	

1.3.2 proposed pricing for the prescribed assets

Based on a deemed capital structure of 42.5% debt and 57.5% equity, production forecasts of 31.5 TWh for the test period for the regulated hydro facilities and 88.2 TWh for the nuclear facilities, an allowed return on equity (ROE) of 10.5%, and a combined return on ratebase of 8.48% in 2008 and 8.56% in 2009, OPG is requesting:

- a payment amount for the regulated hydroelectric facilities of $37.90/MWh for average hourly net energy production (increased from $33.00 per MWh);

- production from the regulated hydroelectric facilities over the hourly volume would receive the market price; and

- a payment amount for the nuclear facilities of $58.2 million per month plus $41.50/MWh. While the unitized amount is less than the previous figure of $49.50/MWh, if the monthly payment is amortized at a 100% load factor,[7] average hourly compensation would be $53.57/MWh.[8]

OPG notes that "a major driver of total revenue deficiency results from the move to a commercial rate of return and capital structure."[9]

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[6] The Beck tunnel project will also be included among the designated assets; although originally expected to come online in late 2009, OPG's February 29th, 2008 press release noted that "considerable uncertainty remains with respect to the schedule…"

[7] The 100% load factor is used purely for illustrative purposes; nuclear plants are, of course, subject to periodic outages. Use of a lower load factor would increase the unitized number further.

[8] Figures taken from OPG Application EB-2007-0905 Exhibit A1, Tab 2, Schedule 2, as updated 2008-03-14, pp. 1-2.

[9] OPG Application EB-2007-0905 Exhibit A1, Tab 3, Schedule 1, as updated 2008-03-14, p.8.

1.3.3 variance and deferral accounts

In addition to the payment amounts described above, OPG also seeks the continuation of a series of variance and deferral accounts, as well as payments to clear certain balances in those accounts. Details are as follows:

- recovery of current variance and deferral account balances associated with the nuclear assets through a payment rider of $1.45/MWh, with similar account balances for the hydro assets being recovered directly in the calculation of the payment amounts described above;

- continuation or establishment of variance and deferral accounts for:

    - variance in hydrology from forecast conditions;
    - deviation in assumed ancillary service revenues;
    - deviation in actual from forecast refurbishment costs for potential refurbishment of Pickering B and Darlington generating stations;
    - deviation from forecast non-capital costs for planning and preparation for development of proposed new nuclear generation facilities;
    - deviation between actual and forecast nuclear fuel costs;
    - variances associated with water transactions and interactions with Hydro Quebec;
    - deviations associated with specified pension benefit expenses;
    - deferral account to record non-capital costs associated with the planned return to service of units at Pickering A;
    - deferral account associated with changes in the nuclear decommissioning liability;
    - a variance account to capture impact of changes in tax rates.[10]

1.3.4 payment process for the prescribed assets

OPG receives payment directly from the Independent Electricity Market Operator (IESO) for output from the prescribed assets. As such it is not directly exposed to counterparty payment risk except to the extent that IESO rules allocate costs of member defaults to all members. OPG, like all generators in the Ontario market, accepts this credit risk based on IESO's own credit risk management policies which require all spot market participants to meet specific standards for creditworthiness.[11] IESO itself does not have a credit rating.

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[10] OPG Application EB-2007-0905 Exhibit A1, Tab 2, Schedule 2, pp. 3 and 4, as updated 2008-03-14.

[11] OPG Management's Discussion and Analysis, 2007 Report, p. 52.

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The IESO market rules set forth the requirements for all participants in IESO administered markets. In carrying out its settlement responsibility, the IESO issues settlement invoices to each market participant.[12] Each market participant is required to pay the full net invoice amount by the market participant payment date. On the IESO payment date, the IESO determines the amounts available in the IESO settlement clearing account for distribution to market participants. If necessary, the IESO borrows funds to enable the IESO settlement clearing account to clear.

As a condition of purchasing energy in the Ontario markets, a market participant must provide the IESO with prudential support to guard against payment default. However, as a result of reductions for creditworthiness or good payment history, the prudential support held could be less than a defaulted amount. the risk management objective of prudential support is to obtain a level of financial security that adds a reasonable degree of protection to participants in the IESO administered markets against a default levy occurring.

If the full amount due by the market participant has not been remitted, default interest accrues on all amounts outstanding.[13] The defaulting market participant must pay the balance by making a prepayment into the IESO prepayment account. The IESO then can initiate the transfer of necessary funds from the IESO's prepayment account to the IESO settlement account to discharge the market participant's outstanding payment obligation.

If necessary, the IESO can recover the aggregate of any amounts owing to the IESO by means of a default levy which is the aggregate of the market participant's default amount, including the net invoice amount plus any default interests, and any costs incurred in investigating the default in payments.[14] In addition to the imposition of different default levies, the IESO has the authority to issue a suspension order.

1.4 intended role of the regulated payments to OPG prescribed assets

At the time that the Electricity Act of 2004 was finalized, the Ontario government listed several objectives related to the setting of regulated payment to the prescribed assets. These included:

- "easing the burden on taxpayers"
- reducing "price volatility"
- "stabilizing" electricity prices
- assuring that Ontario prices are "competitive" with neighboring jurisdictions.[15]

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[12] IESO Market Rules, Chapter 9, Section 6.10 and 6.11

[13] IESO Market Rules, Chapter 9, Section 6.14

[14] IESO Market Rules, Chapter 2, Section 8.1

[15] Ontario Ministry of Energy press release, 23rd February 2005, "Ontario Government Introduces Fair and Stable Prices for Electricity from Ontario Power Generation."

The first of these goals suggests that a long term objective is to reduce the suppression of equity returns for OPG whereby taxpayers are essentially subsidizing ratepayers. This implicit subsidy occurs when OPG is forced to accept a less than commercial return on its assets – taxpayer money is thus being invested at a lower return than it would otherwise earn. The Memorandum of Agreement between the province and OPG states that "as an OBCA corporation with a commercial mandate, OPG will operate on a financially sustainable basis and maintain the value of its assets…" Earning less than an appropriate return on capital would be contrary to this objective.

However, additional rationales can be applied. The prescribed assets are essentially legacy assets; ratepayers would make the argument that, over time, they have already paid for a portion of these assets through previous rates.[16] Thus, during a transition to a competitive wholesale market, gains associated with a move to market based, rather than cost based, revenues for valuable baseload assets could result in a windfall to the incumbent unless mechanisms are put in place that retain these benefits for ratepayers.

Establishing payments to the prescribed assets is essentially a mechanism which allows customers to benefit from these legacy assets and to avoid transfer of windfall profits to shareholders. However, avoidance of windfall profits does not suggest that OPG should make no profits on the prescribed assets; instead, it suggests that returns should be regulated consistent with the fact that the capital to build the assets was provided by ratepayers long before OPG was established, and that OPG's risk profile for assets with a long operating history is quite different from that for a greenfield plant where new capital is being provided, construction risk exists, and operational challenges from newly installed equipment are likely to arise.

[16] Note that ratepayers are already paying for stranded costs associated with the nuclear assets through a separate charge, and that write downs were taken on some of the assets during the period when OPG was created.

2 Definition of risk and its role in determining an appropriate ROE/capital structure for OPG's prescribed assets

Determining the relative attractiveness, stability, and certainty of various securities requires a degree of judgment. As the eminent US regulator Alfred Kahn said, regulators must seek a "zone of reasonableness" within which to base their decisions.[17] To a certain degree, use of a risk-adjusted rate of return allows us to compare entities on a consistent basis – a security of similar risk to another, but which has a higher return, can be assumed to be more "attractive." A more "stable" security would be one whose returns were less volatile than some chosen benchmark, perhaps a market index. "Certainty" can be expected to be correlated to stability; the more "certain" returns are, the more stable we would expect valuations to be.

In this context, it is important to develop a sound understanding of what we mean by "risk." The risk to equity holders of the prescribed assets is derived not only from the nature and technologies of the assets themselves, but also by the way in which the payment schemes and variance and deferral accounts result in customers assuming some of that underlying risk. To the extent that these arrangements reduce the volatility of earnings for equity, "certainty" and "stability" are increased. In a subsequent section, we will examine in more detail precisely how these arrangements serve to mitigate risk, and the relative attractiveness of various entities for which the allowed returns and capital structures are known. In this section, we will discuss further the concept of risk itself.

Among the first academic definitions of risk was one advanced in 1921 by the economist Frank Knight. He attempted to distinguish between risk and uncertainty, terms which had commonly been used interchangeably. He wrote

> ... Uncertainty must be taken in a sense radically distinct from the familiar notion of Risk [*sic*], from which it has never been properly separated. The term "risk," as loosely used in everyday speech and in economic discussion, really covers two things which, functionally at least, in their causal relations to the phenomena of economic organization, are categorically different. ... The essential fact is that "risk" means in some cases a quantity susceptible of measurement, while at other times it is something distinctly not of this character; and there are far-reaching and crucial differences in the bearings of the phenomenon depending on which of the two is really present and operating. ... It will appear that a measurable uncertainty, or "risk" proper, as we shall use the term, is so far different from an unmeasurable one that it is not in effect an

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[17] "The courts and commissions have characterized the entire task of setting 'just and reasonable rates,' and particularly that portion representing return to shareholders, in terms of reaching an acceptable compromise between the interests of investors in the one hand and consumers on the other. The conception is that there is no single, scientifically correct rate of return, but a 'zone of reasonableness,' within which judgment must be exercised." - Kahn, Alfred, *The Economics of Regulation: Principles and Institutions*, Cambridge, MA: MIT Press, 1988, p. 42/I.

> uncertainty at all. We ... accordingly restrict the term "uncertainty" to cases of the non-quantitive type.[18]

Knight made a distinction between *a priori* probabilities, where the probability of an outcome is determined by an inherent symmetry (such as the probability of getting a heads or a tails in a coin flip) or statistical probabilities, which we can determine only by examining homogenous data. Knight therefore defines risk as being a "measurable uncertainty". One problem with this definition is it does not relate risk to outcome. Knowing the probability of an event occurring tells us nothing about the consequences of that event.

Glyn A. Holten, in a 2004 paper, defines risk as being the "exposure to a proposition to which one is uncertain"[19]. Here, "exposure" means the degree to which a given outcome has a material consequence. For example, there may be a non-zero chance that the stock market will decline, but if we own no stocks our exposure is none and so our risk is zero. Mathematically, risk may be quantified as follows:

$$R = P * C$$

which states simply that a given risk (R) is equal to the probability that an event will occur (P) times the cost (C) incurred as a result. This concept is particularly relevant to the nuclear business, for example; while nuclear plants have similar forced outage rates to other plants, the potential cost incurred from the outage may be significantly higher than for a fossil or hydro plant.

From a statistical perspective, risk has generally been measured in terms of standard deviations from the mean. This comes up most prominently in portfolio analysis, where, in comparing two investment strategies, the one whose potential payoff or loss has a higher standard deviation is defined to be the riskier investment. From a financial perspective, therefore, risk is related directly to an investor's willingness to accept greater variability in overall return. Key to this is the fact that willingness to accept higher risks is not the same thing as being willing to accept an uncertain outcome.

A distinction is often made between hedgeable and un-hedgeable risks. As one author notes, "The former are typically risks which can be hedged with tradable assets for which a unique market value exists"[20] The ability to hedge against a risk is limited by the liquidity (or lack-thereof) of futures markets, or the availability of counterparties willing to underwrite customized hedging or insurance packages.

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[18] Frank Knight, *Risk, Uncertainty, and Profit* (1921), I.I.26.

[19] Glyn A. Holton, "Defining Risk", *Financial Analysts Journal* (2004), vol. 60, no. 6.

[20] Kriele, Marcus and Jochen Wolf, "On Market Value Origins and Cost of Capital", Blätter DGVFM (2007) 28: 195–219

> In an ideal situation, one can achieve a so-called *perfect hedge* which completely eliminates the risk associated with a future commitment to deliver by taking an equal and opposite position in the futures market. However, this strategy implies the existence of futures contracts that exactly match the supply commitments. Depending on the maturities of forward contracts, the availability of matching futures and the creditworthiness of other derivative product alternatives varies.[21]

The proposed arrangements surrounding revenues to OPG's prescribed assets do not result in a perfect hedge. At the same time, however, the structure of the variance and deferral accounts, as well as the fixed value of the payments themselves, do increase the stability of OPG revenues and profits. To the extent that other entities in North America do not benefit from such hedges, it would be reasonable to expect that such entities would be allowed to earn a higher return on equity than would be appropriate for the prescribed assets. Likewise, if these arrangements do in fact stabilize net revenues, a greater amount of debt may be attributed to the prescribed assets, as predictable cash flows allow financial institutions to reduce required debt service coverage ratios.

[21] Medova, E.A. and A. Sembos, "Price Protection Strategies for an Oil Company", Presented at the 9th International Conference on Stochastic Programming, Berlin, Germany, August 2001.

3 Salient risk factors

Focusing more intently on specific risk factors, OEB staff identified 14 potential salient risk factors associated with the prescribed assets for LEI to consider; LEI augmented the list and reconfigured some of the identified factors. LEI views the risk factors for the prescribed assets as falling into four broad categories: risks related to corporate structure, risks associated with cost recovery, operational risks, and political risks. For the prescribed assets, we believe that the greatest risks borne by equity are in the operational and political realms.

Throughout this section, we provide an assessment of the directional impact of various risk factors and the proposed arrangements on equity premiums and the ability to raise greater amounts of debt. We do not intend to suggest that raising more debt equates to an optimal capital structure; rather, our intent is to show that within an optimal capital structure, greater leverage can be obtained if the identified risks are mitigated.

3.1 corporate structure

Figure 3. Directional impact of corporate structure risk factors on equity risk premium and ability to raise debt

potential risk factor	IMPACT ON: equity premium relative to regulated Ontario wires companies	equity premium relative to merchant generator	ability to raise higher amounts of debt
OPG ownership	none	none	increases ability
stand alone principle	not applicable	decreases premium	increases ability
ONFA	not applicable	decreases premium	increases ability
reliance on OEFC for financing	none	decreases premium	increases ability
portfolio composition	not applicable	decreases premium	increases ability

As noted previously, OPG was set up as a commercially-oriented Ontario business corporation, just as are virtually all other entities regulated by the OEB. Viewed in isolation, it is not clear that OPG's corporate structure in and of itself should make it any more or less risky than other entities regulated by the OEB. Thus, with some limited exceptions, corporate structure alone cannot be used as justification for a higher or lower allowed return or different capital structure from other OEB-regulated entities. Below, we discuss in greater detail aspects of OPG's corporate structure, including its ownership, relationship of the prescribed assets to other assets in OPG's portfolio, the effect of the Ontario Nuclear Funds Agreement (ONFA), the role of the Ontario Electricity Finance Corporation, and the portfolio composition of the prescribed assets.

3.1.1 ownership of OPG

Ownership of OPG by the province is a double-edged sword. We would argue that such ownership on par is moderately beneficial to debt-holders, but increases risk to equity. OPG's credit ratings clearly benefit from a halo effect caused by government ownership. The assumption is that the province will not allow OPG to default on its debt (held by OEFC); the cost of this guarantee to OPG is likely far lower than if it had to obtain such credit insurance from an AA rated third party. Standard and Poor's comments that "the ratings on Ontario Power Generation… reflect the close relationship between the company and its highly rated owner, the Province of Ontario."[22] Similarly, DBRS states "ratings on OPG continue to be supported by a sole shareholder, the Province of Ontario."[23] This support reduces the cost of borrowing for OPG by at least 89 basis points.[24]

While ownership by the province should enable OPG to directly or indirectly raise more debt than it could as an independent entity, the more debt OPG raises, the greater the risk to equity, since equity distributions are subordinated to debt. Although on a practical basis the real life impact of the observations of Modigliani-Miller[25] may not be continuous – i.e., within a broad range it may be possible to increase debt without equity holders demanding perfectly counterbalancing increases in their equity returns – broadly speaking increases in debt levels increase both the cost of debt and the cost of equity. As DBRS notes "[we] would expect the Province to forgo dividends during a period of heightened capital expenditures if necessary to preserve the Company's credit metrics."[26]

Of greater concern, however, is the provincial government's tendency to use OPG as an instrument of public policy rather than an entity which seeks to maximize profits as would a true commercially oriented enterprise. Use of ministerial directives[27] to set investment policy may at times violate the principles of least cost long term planning or that a commercial company chooses projects based on the highest risk-adjusted rate of return. While failure to behave in a commercially sensible fashion increases equity risk, it is not clear that OEB should be in the business of compensating equity for the increase in risk due to equity's own decisions. Ultimately voters will determine whether directed investments met social goals in a fashion which compensated them for any potential lost profits; OEB should base its decisions more narrowly on risks to equity *assuming* equity holders behave in a commercially reasonable fashion. Put another way, political risks imposed by the government on OPG should only be considered to the extent that a normal commercial company would also be subject to such political risks.

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[22] Standard & Poor's, Corporate Ratings, Ontario Power Generation, Inc., September 29th, 2006, p.1.

[23] Dominion Bond Rating Service, Ontario Power Generation Rating Report, November 30th, 2006, p.1

[24] Based on a comparison of average annual S&P 10-year AA and BBB+ corporate bond yields from 1996-2007, Bloomberg, April 15th, 2008. Note that we disagree with the argument that only Canadian debt markets should be considered, and the corresponding conclusion of a shallow market for low investment grade debt. Canadian power sector entities have been successfully issuing both debt and equity in US markets for several years; indeed, LEI has advised Canadian power sector entities on issues related to such issuances.

[25] F. Modigliani and M. Miller, "The Cost of Capital, Corporation Finance and the Theory of Investment", *American Economic Review*, June 1958.

[26] Dominion Bond Rating Service, Ontario Power Generation Rating Report, November 30th, 2006, p.2.

[27] See paragraph B2 of the Memorandum of Agreement between Her Majesty the Crown in Right in Ontario (the "Shareholder") and Ontario Power Generation ("OPG").

3.1.2 appropriateness of the "stand alone" principle

It is appropriate to consider the prescribed assets on a "stand alone" basis for several reasons. First, OEB was charged with the task of setting rates for the prescribed assets, rather than for OPG's entire portfolio or for OPG as an entity. To consider revenue from the remainder of OPG's portfolio would potentially result in rates that are less than just and reasonable for the prescribed assets themselves. Furthermore, revenues from the non-prescribed assets are subject to their own constraints; further burdening OPG by discounting allowed revenues to the prescribed assets would potentially result in a double penalty to the firm.

The non-prescribed assets and the prescribed assets are not in fact substitutes. Nuclear stations, for example, are highly inflexible; once running, a company's incentive is to keep them running at a steady rate of output for as long as is possible as it is costly and technically challenging to vary production levels. It is simply not technically feasible for OPG to gain some advantage by substituting non-prescribed assets, which have a much higher degree of operating flexibility, for the nuclear non-prescribed assets; the same can be said for the run-of-river components of the hydro assets.

Figure 4. OPG non-prescribed assets

Asset	Capacity (MW)
Non-prescribed hydro	
Ottawa St. Lawrence	1,527
Northeast	1,324
Northwest	669
Evergreen Energy	120
Non-prescribed fossil	
Nanticoke	3,960
Lennox	2,120
Lambton	1976
Thunder Bay	306
Atikokan	211
Wind	7
Total	**12,220**

Source: OPG 2007 Fact Sheet - http://www.ontariopowergeneration.com/investor/pdf/2007factsheet.pdf

Furthermore, the structure of the payment mechanism for the prescribed assets currently is based on volumetric payments – if the units do not run for reasons other than water availability (on the part of the hydro assets), OPG does not get paid. It is highly unlikely that OPG would be able to use the non-prescribed assets to substitute for prescribed assets and increase its revenue, rather than running the prescribed assets as much as possible. The hydro incentive payment structure further prevents this from happening, since the less the hydro assets run, the less likely they are to be able to sell some output at market based rates. Many of the non-prescribed assets have marginal costs that are higher than the prescribed assets, or are subject to dynamic constraints and water availability themselves, further limiting the profitability of substitution. Even were OEB to approve the fixed monthly payment for the nuclear facilities, the overall inability to increase profits through substitution would likely still hold.

Notwithstanding the fact that OPG may at times be able to use its non-prescribed assets to provide power during periods when the prescribed assets are unavailable, we do not feel that it is appropriate for OEB to consider this fact in assigning an appropriate return or capital structure to the prescribed assets. The non-prescribed assets are not rate-regulated by OEB. Were OPG a normal commercial company, it could choose whether to hedge its operational risk on the prescribed assets with other, non-regulated assets, through financial hedges, or not at all. To adjust the rate of return or capital structure for the prescribed assets based on other assets currently owned by OPG (some of which are to be shut down per government decree) would be to bring into rate regulation assets which are not at the present time intended to be so regulated. The appropriate comparison would be, for example, if a municipal utility chose to spend shareholder money on distributed generation in a region of its network which experienced higher outage frequencies. The fact that this investment in distributed generation could earn more when the network is out of service is not a justification to reduce the risk premium on the wires business -- the asset baskets are completely separate.

3.1.3 effect of the ONFA between Government of Ontario and OPG

The ONFA sets forth the delineation of financial responsibilities between OPG, the province, and OEFC with regards to treatment and storage of used nuclear fuel bundles. Among other provisions, it allows for OPG to obtain a financial guarantee, if needed, from OEFC, and it caps OPG liability related to used fuel. While the ONFA does not eliminate uncertainty for OPG with regards to treatment of nuclear waste, it does better define it, with among other provisions the province paying an increasing share of the obligations to the Used Fuel Segregated Fund related to projected costs above $4.6 billion, and all of the cost in excess of $10 billion.[28] Essentially, OPG is receiving, at little cost, insurance from Ontario taxpayers which limits OPG liabilities related to treatment of spent fuel.

This insurance reduces risk to hypothetical debt and equity investors in the prescribed assets. Uncertainty regarding future liabilities is bounded, and reasonable base case and worst case scenarios can be factored into the decision of hypothetical investors regarding the degree of additional yield required to bear this risk. The ONFA significantly reduces any uncertainty premium hypothetical investors would demand related to nuclear fuel treatment and site remediation. The ONFA is not anomalous; in the United States, nuclear power station

[28] Ontario Nuclear Fuels Agreement, April 1, 1999, p. 35.

operators benefit from Federal limits on liability[29] as well as from a delineation of responsibilities regarding short and long term storage of nuclear waste[30].

3.1.4 OPG reliance on OEFC for debt financing

The Electricity Act of 1998 mandates that the OEFC provide financial assistance to the successor corporations of Ontario Hydro.[31] The OEFC provides financing on commercial terms to OPG in order to develop new electricity supply projects. OEFC financing costs are repaid from interest on notes receivable from OPG and from dedicated electricity revenues in the form of payments-in-lieu of corporate income, capital and property taxes made by OPG.

Overall, we are of the view that OPG reliance on OEFC for debt financing is a risk (and cost) mitigant. Whether OEFC is being appropriately compensated for this service is a matter outside of our purview. However, from OPG's perspective, relying on OEFC for financing means that OPG need not repeatedly justify its proposed investments to every major investment bank on Bay Street every time it seeks financing. Furthermore, it means that, from the perspective of those working with OEFC on debt financings, OPG is viewed as part of a larger provincial financing account, resulting in better potential pricing. Finally, the ability to rely on OEFC for debt financing means that OPG is partially shielded from market disruptions like the recent credit crunch which has delayed financing for large capital intensive projects both in and outside of the electric power industry.

3.1.5 prescribed asset portfolio composition

The composition of the prescribed asset portfolio reduces risk to equity relative to other possible generation asset portfolio configurations. The portfolio is comprised of baseload assets with limited dispatch risk, as will be discussed further in a later section. It is not composed of a single asset or technology, many of the stations consist of multiple units, and the technologies deployed are well-understood.

While the age of the hydro assets means that various capital refurbishment programs may become increasingly economic, such programs often also result in improved potential output from a given amount of water. For hydro assets, the prescribed assets themselves show that the actual operational life can be extended repeatedly. This is less true for nuclear stations, though recent programs across North America to extend operating lives of nuclear stations have been

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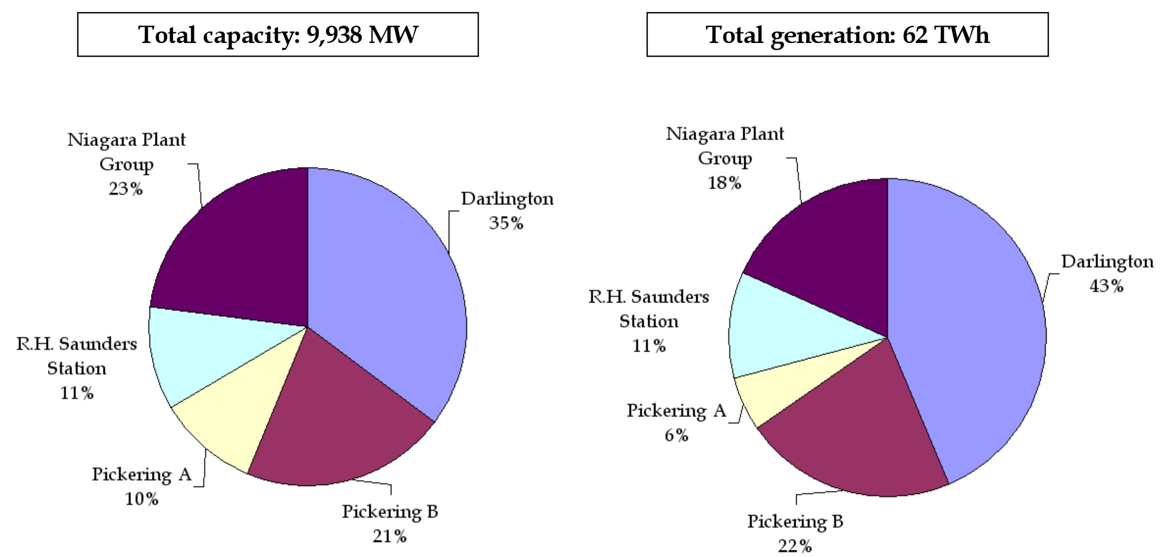
29 The Price-Anderson Nuclear Industries Indemnity Act, originally enacted by the US Congress in 1957, limits the liability of the nuclear industry by providing compensation of member of the public who incur damages from nuclear or radiological incidents; latest extension 2005 under the Energy Policy Act of 2005.

30 The Nuclear Waste Policy Act of 1982 requires utilities which generate electricity using nuclear power to pay a fee of one tenth of one cent ($0.001) per kilowatt-hour into the Nuclear Waste Fund. The Fund is responsible for the management and disposal of high-level radioactive waste and spent nuclear fuel. As of 2007, payments and interest credited to the Fund totaled $27.2 billion.

31 Electricity Act, 1998, S.O. 1998, Chapter 15, Schedule A, Section 54.

successful. As the nuclear stations reach the end of their design lives, replacement or life extension programs need to be considered. However, the fact that stations may be in the second half of their design lives does not in and of itself increase risk to investors; an investor may know that an asset has a finite life, but that investment may still be attractive given the yields involved and the stability of cash flows throughout that life. Even if an aging station requires more maintenance (and new stations often pose their own maintenance challenges), the amounts involved are not unknown or surprising, and can be factored into the investment decision.

Figure 5. Comparing capacity and output of OPG prescribed assets



Source: OPG 2007 Factsheet

There is nothing unique to the nature of either hydro or nuclear assets which significantly increases risk relative to other assets. Furthermore, combining the two into a diversified multi-plant portfolio reduces overall risk. While hydro stations face fluctuations in hydrology, long term hydrology is often cyclical, rather than random; average hydrology is predictable,[32] even if hydrology in a particular year is not. The prescribed assets are protected from fluctuations in revenue due to hydrology by variance accounts, an insurance product provided by ratepayers to which a private, non-regulated hydro generator would not have access. It is worth noting that fossil fuel plant operators can face significant fluctuations in fuel costs, and also face greater dispatch risk; in this context, hydrology risk may present a lower risk relative to fuel price volatility.

[32] While climate change would appear to be having an effect on hydrology, this impact may be less profound presently in Canada than in some South American countries.

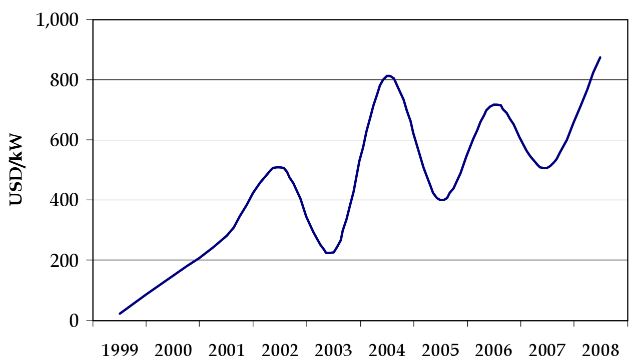
Figure 6. Standard deviation of average annual output of OPG's prescribed hydro assets and annual Dawn hub gas prices

	Standard deviation (as a % of the mean)
Output OPG prescribed hydro assets	3.4%
Dawn hub gas prices	16.1%

Source: IESO, OPG for annual outputs, Bloomberg for annual gas prices; years covered from 2004-2007

Market risk perception of nuclear assets in North America has changed significantly over the past decade. During the early 1990s, nuclear assets were considered risky, with many assumed to potentially be unable to operate for their entire license period. In fact, as a portion of the nuclear fleet transitioned from ratebase to merchant operations, load factors improved, license extension applications were prepared, and capacity increases were implemented at existing plants. The price paid by new investors for nuclear plants increased dramatically. At a time when major banks are rethinking their ability to provide debt to new conventional coal stations, the ability to raise debt on existing nuclear stations has improved. In fact, a large US utility and merchant nuclear plant operator has announced plans to spin off its merchant nuclear operations into an independently traded entity. As Entergy noted in its 2007 annual report, "[the independent nuclear company] expects to execute roughly $4.5 billion of debt financing… a stark contrast to when we started this business and it had to be all internally financed" with equity.[33]

Figure 7. Nuclear power plant sales in the US



Source: World Nuclear Association[34]

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[33] Entergy Annual Report 2007, p.3.

[34] Chart created by LEI based on data from World Nuclear Association table, US Nuclear Power Plant Sales 1999-2008.

While it is true that nuclear assets do entail risks somewhat greater than other generation assets, that risk is less due to reliability than it is due to the costs involved when an unplanned outage actually takes place. If OPG's proposal is approved, the nuclear assets would be protected from fuel price risk with a variance account, and while OPG does bear some operating risk associated with the stations, it is not [unlike other jurisdictions] at risk for replacement power costs. Although fully regulated vertically integrated utilities are often able to pass through most generation-related costs, state regulatory commissions have often shown little patience with such regulated entities attempting to pass through the costs of replacement power where the length of a nuclear outage appeared to be caused by a failure to follow good utility operating practice. In Ontario, customers, not OPG, are required to bear the cost of more expensive power when OPG nuclear stations are less reliable than expected; OPG faces the prospect of lost revenues, but not the potentially much more expensive prospect of having to replace lost power.[35]

Overall, the prescribed asset portfolio composition results in a diversified set of low risk assets which would be capable of being financed on a stand-alone basis with a moderate risk premium.

3.2 cost recovery mechanisms

Risks falling within the cost recovery mechanisms category include the timing and nature of rate reviews, recovery requirements of variance accounts, the impact of the variance accounts themselves, the impact of the fixed monthly payment, impact of full regulation for the prescribed assets, and the impact of bonus revenues and ROE associated with the hydro incentive mechanism. Over all, the various cost recovery mechanisms associated with the prescribed assets serve to reduce risk; while full recovery of costs for OPG is not guaranteed, overall risk, when defined as volatility of expected net revenue streams, is reduced.

Figure 8. Directional impact of cost recovery mechanisms on equity risk premium and ability to raise debt

potential risk factor	IMPACT ON: equity premium relative to regulated Ontario wires companies	equity premium relative to merchant generator	ability to raise higher amounts of debt
timing and nature of rate review	increases premium	not applicable	decreases ability
recovery of variance and deferral accounts	none	decreases premium	increases ability
existing and proposed variance accounts	none	decreases premium	increases ability
impact of fixed monthly nuclear payment	decreases premium	decreases premium	increases ability
impact of assets being fully regulated	none	decreases premium	increases ability
impact of bonus revenues	none (assuming 3GIRM)	decreases premium	increases ability

[35] American Electric Power (AEP), one of the largest electric utilities in the US, agreed to bear most of the costs related to the company's 1997 shut down of its Donald C. Cook nuclear plant. Besides the costs associated with consumer refunds, the proposed rate freeze, and increased annual payments to its nuclear decommissioning fund, AEP faced substantial costs associated with the replacement of power. Source: 10-Q SEC filing by American Electric Power on 5/17/99

3.2.1 uncertainties related to timing and nature of rate review

One aspect of the cost recovery mechanisms which does increase risk for OPG is the timing and nature of rate reviews for the prescribed assets. Until the duration of regulatory periods and the process by which rates are set is better established, OPG faces risk associated with its ability to recover costs in a timely fashion. Of course, to the extent that OPG is able to reduce costs, it may be able to benefit from a regulatory lag effect, in which the prices it receives are slow to adjust to true cost of service. In that sense, the risk is somewhat symmetrical – OPG is at risk of costs rising more rapidly than can be adapted through a rate filing, but benefits during periods when costs are falling. However, the lack of clearly established rules and procedures makes it difficult for OPG to assess the durability of the current regulatory regime. On par, this likely increases equity risk and would be a factor in debt raising were OPG to be raising debt independently for the prescribed assets. This issue is related to, though distinct from, political risk as discussed further below, in that political risk also incorporates larger potential changes in public policy.

Proposed variance accounts

- ✓ variance in hydrology from forecast conditions;
- ✓ deviation in assumed ancillary service revenues;
- ✓ deviation in actual from forecast refurbishment costs for potential refurbishment of Pickering B and Darlington generating stations;
- ✓ deviation from forecast non-capital costs for planning and preparation for development of proposed new nuclear generation facilities;
- ✓ deviation between actual and forecast nuclear fuel costs;
- ✓ variances associated with water transactions and interactions with Hydro Quebec;
- ✓ deviations associated with specified pension benefit expenses;
- ✓ deferral account to record non-capital costs associated with the planned return to service of units at Pickering A;
- ✓ deferral account associated with changes in the nuclear decommissioning liability;
- ✓ a variance account to capture impact of changes in tax rates.

3.2.2 recovery requirement of existing variance and deferral accounts per Regulation 53/05

Regulation 53/05 set forth both the starting set of variance and deferral accounts to be established by OPG, and the terms under which they were to be treated. Thus, variance accounts are to be recovered over a period of three years, and earn interest at the rate of 6%; recovery periods for deferral accounts vary between three and fifteen years. In general, Regulation 53/05 satisfies two key criteria for dealing with variance and deferral accounts: the timing for recovery is set forth clearly, and by establishing an interest rate associated with the accounts Regulation 53/05 recognizes the time value of money. Overall, the recovery requirements set forth in Regulation 53/05 reduce business risk to OPG by reducing the degree of discretion that is left to the regulator. While there is arguably a disconnect in the fact that the interest rate should more properly be based on OPG's weighted average cost of capital, this disconnect is outweighed by the value provided by the clarity of treatment and increased certainty of recovery.

3.2.3 existing and proposed variance accounts

As noted previously, the existing and proposed variance accounts shift a number of risks related to the prescribed assets from OPG to ratepayers. It is important to note two things, however. First, although merchant generators[36] operate in competitive wholesale markets without the benefit such mechanisms, regulated entities often do; variance and deferral accounts are a normal part of cost-of-service ratemaking. Fuel cost adjustment mechanisms, for example, can be found in a number of regulated jurisdictions[37]; the hydrology and nuclear fuel accounts serve a similar purpose.

A number of other accounts allow for OPG to recover variations from forecast costs for potential refurbishment, planning and preparation for new nuclear generation, and for Pickering A return to service. While additional costs incurred by OPG must be shown to be prudent, the arrangements reduce equity exposure to potential cost overruns – again, ratepayers are providing insurance against cost overruns, and underwriting certain business development costs. Jurisdictions where utilities remain vertically integrated and continue to be regulated vary on the extent to which such costs can be recovered. Generally, where commissions want to encourage utilities to undertake business development for projects which face a high degree of regulatory risk, advance cost recovery or the creation of associated regulatory assets is allowed. This shows that the practice of establishing variance and deferral accounts, in addition to being consistent with provincial policy, can also be observed in other jurisdictions across North America.[38]

It is clear that the variance and deferral accounts serve to reduce business risk to OPG. OPG's exposure is reduced with regards to fluctuations in water availability, uranium prices, and increased costs associated with refurbishment planning, planning for new nuclear capacity, and addressing the Pickering A return to service. At the same time, however, the arrangements do not completely shield OPG from risk – OPG retains a degree of operating risk, despite being protected from the impact of several other variables.

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[36] For the purposes of this paper, a merchant generator is a privately-owned entity which receives a portion of its revenues from sales into spot markets. Merchant generators, sometimes referred to as independent power producers or IPPs, may vary in the amounts and length of contract cover that they have arranged, but all operate according to commercial principles and put shareholder equity at risk.

[37] For example. the Public Service Commissions of Oklahoma (Title165. Corporation Commission, Chapter50), Minnesota (Minnesota Public Utilities Commission, Docket No. E-017/M-07-1220) and Florida (State of Florida Public Services Commission, Order No. PSC 02-1484-FOF-EI), among others, incorporate the volatility of fuel costs in their rate making processes.

[38] The types and number of variance and deferral accounts vary widely from utility to utility and state to state. They can include storm recovery reserve funds, various accounts designed to allow utilities to cover the costs of environmental mandates, lost revenue adjustment mechanisms (which may deal with elements other than the impact of conservation, and accounts intended to adjust for the impact of seasonality.

3.2.4 impact of requested 25% fixed monthly payment for nuclear production

Current arrangements for the OPG prescribed assets are entirely volumetric; OPG proposes to change this with regards to the nuclear operations. Use of a fixed monthly payment is another means to reduce business risk for OPG. Use of contracts which have a mixture of fixed and variable components is not uncommon; contracts are often split between monthly fixed payments (sometimes referred to as capacity payments) and volumetric, or energy payments. Customarily, capacity payments represent coverage of the plant's fixed costs, while energy payments are representative of variable costs.[39] However, payment of capacity payments may be linked to the plant achieving certain availability or reliability standards. OPG does not propose such a linkage.

Decreasing the portion of OPG's revenues associated with volumetric payments also reduces fluctuations in revenues due to operational issues – the payment would occur even when one or more nuclear units are out of service. This means that OPG's cash flow is less affected. Again, this is an arrangement which would not be available to merchant generators in a competitive wholesale market, and is not available to generators with OPA contracts. Indeed, it would also not be available to a regulated wires company facing a shutdown of an industrial customer – something less in the control of a wires company, but which could have a similar impact on revenue.

3.2.5 impact of prescribed assets being fully regulated

The impact of the prescribed assets being fully regulated is a risk mitigant for OPG's prescribed assets to the extent that the regulatory regime becomes established and predictable. The regulatory arrangements established for the prescribed assets provide a greater degree of certainty of recovery of fixed and variable costs than would be available to owners of the prescribed assets if the prescribed assets were operated as a separate company. Because the assets are fully regulated, OPG can with greater certainty predict what its revenues will be. While OPG still bears some operational risk, it can call upon its decades of operating history to predict the extent of potential planned and unplanned outages at the units. However, it need not speculate as to what price it will receive for its output; this variable is known, reducing overall expected revenue volatility.

As the figure below shows, if we compare the pricing OPG has proposed for the prescribed assets to the price duration curve for 2007, we can see that, if 2009 prices were to follow a similar pattern, OPG would be giving up some potential profits during periods when prices

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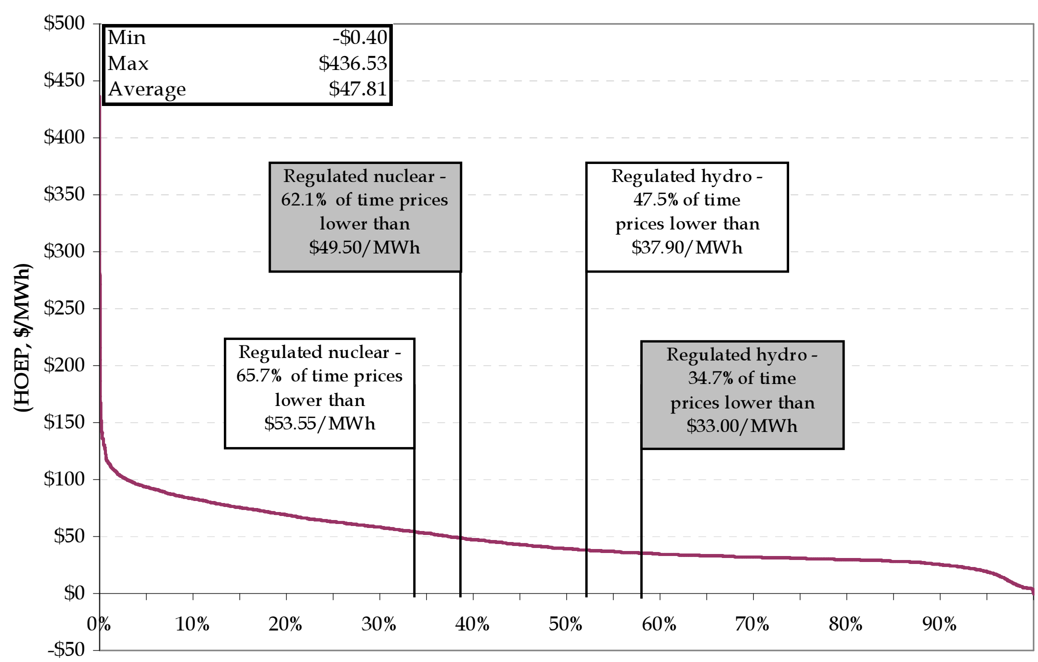
[39] We hasten to add, however, that the fact that some (by no means all) private sector contracts incorporate a capacity payment by no means demonstrates that generators are in any way entitled to recover fixed costs. Even in the markets cited by OPG in the US as having established capacity markets, there is no guarantee that all generators will be able to recover fixed costs, and indeed we can expect capacity prices to fall in real terms if the long run marginal cost of new entry falls due to technological improvements. Existing capacity market designs in the Northeast use the fixed costs of a simple cycle gas turbine for referent pricing; technologies with higher fixed costs will in these markets only recover a portion of their own costs in the capacity markets.

exceeded the regulated prices, but would also be gaining additional profits during periods when prices are lower than the regulated prices that have been set for the prescribed assets. Generally speaking, there may be years in the future in which OPG could earn more under the regulated arrangements than it would were it to be selling its output into the market.[40] While OPG retains some operating risk, and is at risk that certain costs may be deemed imprudent, by eliminating commodity price risk, the fact that the prescribed assets are fully regulated reduces business risks overall.

Figure 9. prescribed asset pricing relative to 2007 Ontario price duration curve



Source: LEI graphic based on IESO data

40 This does not necessarily mean that the regulated prices are not beneficial to customers. First, customers may perceive a benefit from stable prices; long term fixed price contracts can mitigate risks for both buyers and sellers, and the fact that one or the other party ends up paying a premium relative to spot prices which were unknown at the time the contract was entered into does not mean that both parties have not received benefits. Second, regulated prices to prescribed assets reduce OPG's ability to profitably exercise market power, in turn resulting in wholesale prices being lower than they otherwise would have been. Third, the unique structure of the Ontario market likely suppresses peak prices, given that relatively few players rely on the spot market to cover fixed costs for low load factor plant – the very plant likely to need to bid above marginal cost during periods of system stress.

3.2.6 impact of bonus revenues and ROE associated with hydro incentive mechanism

The hydro incentive mechanism provides the opportunity for OPG to earn additional revenues at market rates during periods when it is capable of above average production.[41] This mechanism, for those facilities which have the potential for inter-temporal shifts in production, provides OPG with some degree of market based price signals; when OPG expects prices to exceed the regulated price, it can forgo some production at the regulated price while being assured of being able to produce greater than average volumes during periods when market prices are higher than the regulated price. The mechanism also provides an incentive to assure that the facilities are producing as much as they can out of a given amount of water.

While the incentive may not be perfect, it does provide a partially market based price signal for OPG to manage its water and its assets in a commercially sensible fashion. Ontario ratepayers benefit because water reserved for use in peak periods reduces the use of more expensive peaking units. The modification proposed by OPG – that the incentive be symmetrical, based on average hourly volumes per month based on actual output, with above average production compensated at market prices and below average production charged against the incentive at market prices – corrects a flaw in the existing mechanism whereby the incentive may fall as the regulated price increases relative to the average market price.

If we take the regulated revenues to the prescribed assets in isolation, and assume that we are talking about whether the incentive mechanism increases or decreases business risk associated with the regulated revenues, we can see that the incentive mechanism overall reduces the risk associated with the regulated revenues. As long as the probability of receiving payments under the incentive is greater than zero, that means that the probability of earning revenues in addition to the regulated revenues is greater than zero. This in turn provides for the possibility of making up for production losses due to operational issues. We are skeptical of OPG's claims that the incentive increases risk to OPG because it is symmetrical. Intertemporal shifting remains optional for OPG; it need not shift production if it does not want to. Furthermore, OPG is able to predict the extent to which it would benefit from the incentive; while there is uncertainty around this potential benefit, we do not believe that this uncertainty puts recovery of the revenue requirement at meaningfully greater risk, while the ability to achieve higher revenues may offset revenue shortfalls due to operational issues.[42]

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[41] It is not accurate to claim that OPG can control its monthly output for the hydro stations – while it can curtail its production relative to what it would otherwise produce, and shift that production over the short term, its capabilities are ultimately limited by water availability.

[42] By way of comparison, some OPA contracts incorporate various incentive payments designed to encourage market price responsiveness and additional production when such production is economic. In some cases, particularly for the non-OPG contracts, there is no cap on these incentive payments.

3.3 operational

Operational risks are one area in which the prescribed assets are more risky than regulated wires assets.[43] Simply put, generation assets are more mechanical in nature and entail significantly more complex operating dynamics than most transmission and distribution assets. Forced outage rates on generation assets in general far exceed those of non-generation assets in the electricity system. Revenue volatility can increase due to the performance of individual assets in the prescribed asset portfolio. While the prescribed assets face limited dispatch risk, the nuclear (and hydro) assets do face potential outage risk, and such outages (particularly for nuclear assets) can be of much longer duration than a typical wires outage[44]. While the prescribed asset portfolio benefits from diversification as mentioned above, nonetheless each of the nuclear units is of sufficient size that the loss of a single unit would have a material impact on the prescribed asset portfolio revenues. In terms of operational impacts from changing environmental regulations, the prescribed assets generally have a low air emissions profile and therefore have very little risk of economic or operational impact.

Figure 10. Directional impact of operational risks on equity risk premium and ability to raise debt

potential risk factor	IMPACT ON: equity premium relative to regulated Ontario wires companies	equity premium relative to merchant generator	ability to raise higher amounts of debt
dispatch risk	increases premium	decreases premium	increases ability
nuclear outage risk	increases premium	increases premium	decreases ability
risk of non-payment from IESO	decreases premium	decreases premium	increases ability
impact of potential air emissions regulations	not applicable	decreases premium	increases ability

[43] If we consider only forced outages (times when a plant is called upon and expected to operate but is incapable of doing so) we find that according to the North American Electricity Reliability Council (NERC)'s GADS database, such outages for nuclear and hydro assets occur 3-4% of all hours the unit is expected to operate. By contrast, even when so-called force majeure hours are considered, the expectation of the percentage of minutes that Hydro One's network would be unavailable is 1.65%. Furthermore, this percentage does not cover the entire network, but simply the possibility that part of the network will be unavailable.

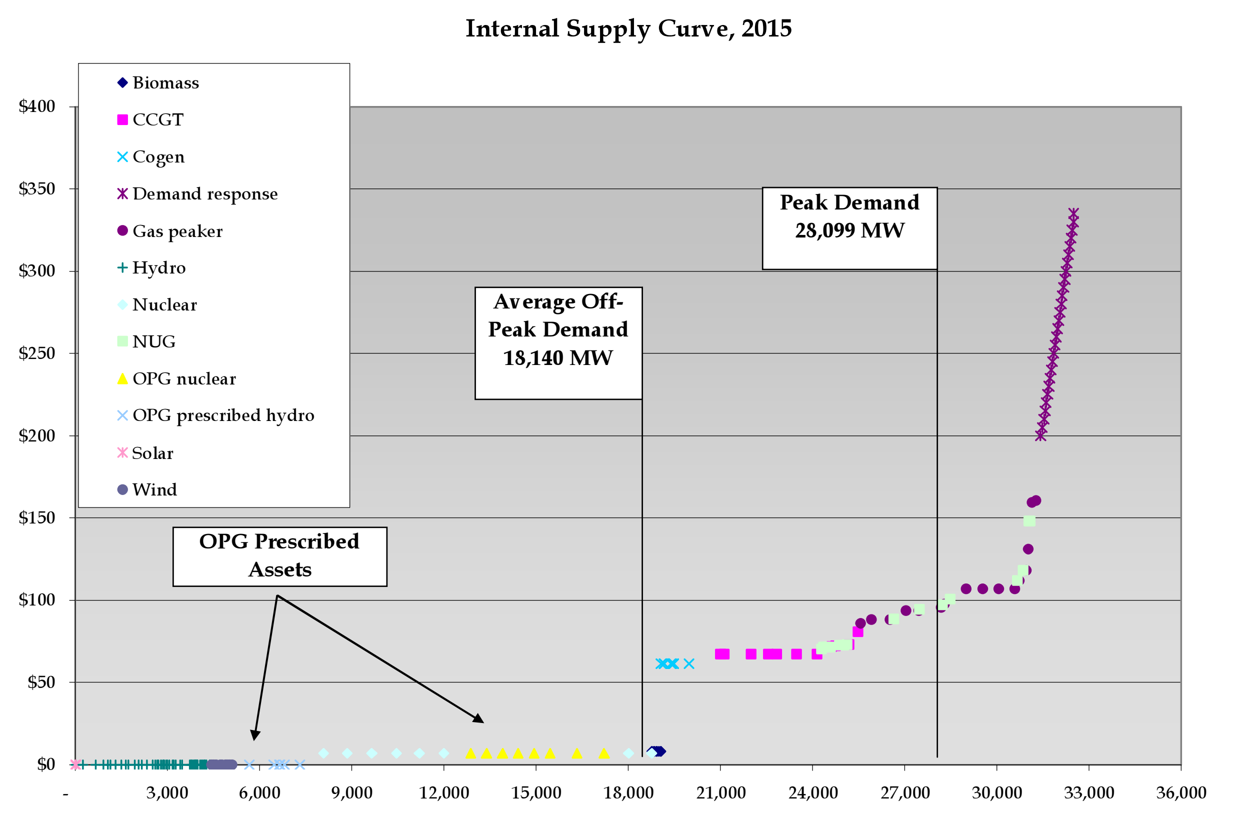
[44] Our focus here is not on whether OPG is a better or worse operator than other generators, but rather whether, as an asset class, the prescribed assets are more or less risky than a regulated wires company. We find that potential revenue volatility, even when a generator operates according to best practice, is higher for generators than for wires companies.

3.3.1 dispatch risk of prescribed assets

As the supply curves below show, the prescribed assets bear limited dispatch risk. Each of the plants in the prescribed asset portfolio has low marginal costs. When we examine the internal supply curve[45] for Ontario, even when we consider 2015 and the Reference Case 1A scenario of the OPA's integrated power supply plan (IPSP), we find that, relative to average off peak demand, all of the prescribed assets would operate under most demand conditions.

Reference Case 1A scenario is one of the two main reference cases developed for IPSP analysis. Case 1A focuses on the dynamics of the supply resources based on assumptions that Pickering B unit is refurbished. According to this scenario over 32,000 MW of capacity is added by 2027, of which about 9,000 MW includes currently committed resources and over 23,000 MW of planned resources.

Figure 11. Indicative position of prescribed assets on hypothetical 2015 Ontario supply curve



Source: *LEI graphic based on proprietary LEI Ontario wholesale power market model*

45 Supply curves shown here are based on load factor adjusted capacity for wind and hydro facilities. Imports are not considered, as it is assumed that imports will be priced above the marginal cost of the prescribed assets. Resources are shown at deemed marginal costs, without shadow pricing.

Note that the OPA scenario used to build the 2015 supply curve includes almost 3,500[46] MW of new wind, as well as robust conservation contributions; it is possible that neither of these assumptions will be met. This is not to suggest that the prescribed assets in a limited number of circumstances do not face some dispatch risk; the observation of negative prices in 2007 proves otherwise. However, as the price duration curve in Figure 9 shows, there were only 4.2% of hours when prices dipped below our assumed marginal cost for the nuclear assets.

3.3.2 nuclear outage risk

> In 2007, outages at US nuclear plants varied in length between one and 109 days. The average annual outage length for 2007 was 3-4 days which is in line with preceding average annual nuclear outage lengths (based on actual scheduled and unscheduled outages of US nuclear plants).
>
> *Source: Global Velocity Suite*

The calculation of the price to be paid for output from the nuclear stations within the prescribed assets likely incorporates to a certain degree the expected outage performance of the units, by factoring planned outages into the number of hours of output across which nuclear costs are spread. Thus, scheduled maintenance may already be accounted for. However, although nuclear plants North America-wide do not tend to be any more unreliable than other technology types, the issue is not so much the probability of occurrence as it is the high and possibly unknown cost of the outage when it does occur. Once taken offline, it can take weeks for a nuclear station to be brought back to full power, and then only if the required repairs are minor. If the cause of the outage is more serious, plants can be offline for six months to a year. The problem is exacerbated if several units share common systems and the common system fails. This means that nuclear operators face a greater degree of uncertainty regarding the cost of outages than do operators of other types of technologies. Although OPG's proposal for a fixed monthly payment equal to 25% of its revenue requirement reduces nuclear outage risk somewhat, OPG's prescribed assets are far more exposed to potential loss of revenues than would be a transmission or a distribution network, or indeed other types of generation assets.

3.3.3 risk of non-payment by IESO

> Each IESO market participant must provide **prudential support** as a condition of participation in IESO-administered markets. The IESO determines, for each market participant, the maximum net exposure as the sum of the market participant's trading limit and the market participant's default protection amount. In order to meet its prudential support obligation, a market participant must provide prudential support in of the following forms: a guarantee of credit which must be provided by a bank with a minimum long-term credit rating of "A" or a credit union licensed by the Financial Services Commission of Ontario with a minimum credit rating of "A"; marketable securities in form of Canadian Government treasure bills; a guarantee from affiliated or non-affiliated persons that have a credit rating as stipulated in the IESO market rules.

Risk of non-payment by the IESO is minimal. IESO members must meet stringent credit requirements, and the cost of defaults, which are rare, are shared pro rata among members. There are no examples of system operator defaults in North America.[47] This places OPG's prescribed assets in a better position than, for example, a merchant generator with contracts, since such a

[46] OPA IPSP assumes total installed wind capacity of 3,466 MW, and effective (reliable) capacity at 666 MW.

[47] California Power Exchange was not also an independent system operator; California ISO has never defaulted.

merchant generator must determine the creditworthiness of each counterparty, and faces bearing the entire loss should a counterparty default. In some ways, these arrangements are even more favorable than those for regulated distribution companies. Regulated distribution companies face counterparty credit risk that is the combined creditworthiness of all of their customers. While regulated distribution companies can always shut off non-paying customers eventually, there is often a lag. Furthermore, although some distribution companies can ultimately include the costs of bad debt in ratebase, this again results in a lag before the distribution company is made whole. Overall, OPG's reliance on the IESO for payment reduces business risk associated with the prescribed assets.

3.3.4 impact of potential changes in air emission requirements

> The **Regional Greenhouse Gas Initiative (RGGI)** is an example of carbon "cap and trade" system, where Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont (District of Columbia, Massachusetts, Pennsylvania, Rhode Island, the Eastern Canadian Provinces, and New Brunswick as observers) have joined forces develop a cap and trade system for power plant emissions.
>
> The **carbon tax** proposed by the government of British Columbia will be applied on the purchase and use of fossil fuels in British Columbia, such as gasoline, diesel, natural gas, heating, fuel, propane, and coal. The carbon tax will be revenue neutral which means that revenues from the carbon tax will be returned to taxpayers through reductions in other provincial taxes.

Compliance requirements with regards to carbon dioxide emissions in North America are evolving. Slow progress at the national level is leading to a host of regional initiatives, such as British Columbia's proposed carbon tax and the Regional Greenhouse Gas Initiative (RGGI) to which many Northeastern US states belong, which is essentially a cap and trade system. While the details of carbon tax and cap and trade systems vary, both result in higher costs for fossil fueled plants. This makes non-emitting plants, such as the prescribed assets, more competitive. Were Ontario to join RGGI, exports from the prescribed assets would potentially be more valuable.

Some generators in Canada have already sold credits associated with renewable attributes to buyers across the US border; as markets become more transparent, more such opportunities may arise.[48] While OPG may not be able to perform such trades for political reasons (Ontarians may confuse the sale of environmental attributes with importing pollution, for example), the trends in both carbon dioxide emissions regulation and in the markets for renewable energy credits suggest that such regulations benefit, rather than harm, the business prospects of the prescribed assets. Evolving environmental policy makes the prescribed assets more attractive relative to merchant generators with significant fossil-fueled assets. By improving the prescribed assets competitive position, and potentially providing an additional revenue streams, it could even be argued that potential emissions regulations improve the risk profile of the prescribed assets relative to wires companies.

3.4 frequency of policy changes and lack of independence of regulators

One of the biggest risks facing power sector investors in Ontario today is the frequency with which government policies are changed, even during the same administration. While all power

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[48] See Bonneville Environmental Foundation, "Canadian 'Green Tags' Flow to U.S. Distributor", June 29, 2004

sector assets in the province face this risk, in some ways the risk is greater for the prescribed assets. To the extent that OPG is viewed as a tool for keeping electricity prices low, rather than as an investment of taxpayers' money which needs to earn an appropriate commercial return, there is the potential for pricing of output from the prescribed assets to be affected. OPG's nuclear program also faces political risks from Federal atomic energy policies. Below, we briefly discuss the impact of policy changes at the provincial and Federal level. In both cases, we feel that the prescribed assets face a higher degree of political risk than either wires assets or merchant generators.

3.4.1 Ontario

In the past decade, Ontario policy towards the electricity sector has been in a state of constant change. After an initial industry restructuring, a brief period of competitive wholesale markets was abruptly compromised by imposed price caps; part-privatization of the provincially-owned wires company was launched, then shelved; a hybrid market structure, with a principal buyer, the OPA, has gradually evolved; announcements regarding the date of the shut down of Ontario's coal plants were repeatedly made, then altered; significant initiatives for conservation and demand management have been initiated; and, after OPA was set up to provide a degree of stability to investors, the future institutional home of OPA's various functions is in doubt.

Figure 12. Directional impact of political risk on equity risk premiums and ability to raise debt

potential risk factor	IMPACT ON: equity premium relative to regulated Ontario wires companies	IMPACT ON: equity premium relative to merchant generator	IMPACT ON: ability to raise higher amounts of debt
provincial political risk	increases premium	increases premium	decreases ability
federal political risk	increases premium	increases premium	decreases ability

Of all of the companies operating in the Ontario power sector, OPG is likely the entity that is most subject to the political agendas of the government of the moment. Hydro One, as a company which, at the distribution level at least resembles many other Ontario wires companies, can convincingly argue in most cases that it should be treated in a similar fashion to Ontario's municipally owned distribution companies. New private investors in the Ontario power sector can rely on the terms of the contracts negotiated with OPA; Ontario does not have a history of forced contract renegotiation, and even were the OPA to be dismantled or merged with another entity, precedence with the Ontario Hydro non-utility generator contracts (which outlived Ontario Hydro) suggests that investors will be unharmed even if the government decides to dismember OPA. Although the policy fluctuations also adversely affect merchant generators without OPA contracts, the Ontario government does not own these generators, cannot force them to lower their prices provided they have been behaving competitively, and does not subject them to ministerial directives. Overall, the biggest potential risk taxpayers face as investors in the equity of the prescribed assets is that the provincial government could take actions that diminish the ability of the assets to earn a reasonable commercial equity return.[49]

3.4.2 Federal

The prescribed assets face political risk from another quarter, however. The nuclear assets are subject to the jurisdiction of the Canadian Nuclear Safety Commission (CNSC). However, just as the province of Ontario faces potential conflicts of interest in its ownership of OPG, the Canadian federal government faces a similar conflict of interest in its ownership of Atomic Energy Canada Limited (AECL). The recent firing of the President of the CNSC has called into question the independence of the CNSC. At the same time, the Canadian government has been actively lobbying provincial authorities to assure that the next generation of nuclear investment provides a role for AECL.

The structure of the deferral and variance accounts provides OPG with a partial hedge against federal efforts to favor AECL. If, for example, OPG began a process to evaluate new nuclear installations at the prescribed asset sites based solely on best quality for least cost principles, only to have that process undermined by federal government actions, OEB would likely regard such costs as being prudently incurred and allowed for recovery, even if OPG were forced to "buy Canadian." However, the arrangements for the prescribed assets do not provide OPG any mechanism to recover costs that arise due to the potential lack of independence of CNSC. Were the federal ruling party to influence the CNSC in a fashion which increased costs to OPG, or increased the uncertainty regarding CNSC actions, OPG would potentially not be able to recover such costs.[50] With the largest fleet of CANDU reactors in Canada, this is a political risk which is unique to OPG.

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[49] We recognize that there is a pernicious outcome in that if we chose to "reward" the prescribed assets with a higher equity return due to political risk, we may appear to be effectively encouraging erratic policy behavior on the part of the owner of the prescribed assets. In this case, however, we are making a distinction between the government, on behalf of the taxpayers, owning the prescribed assets, and the incumbent party, in search of votes, seeking to suppress electricity prices. We believe it is unarguable that the prescribed assets face political risk, even if that risk reflects a conflict of interest at the ownership level.

[50] Some of this political risk may be mitigated to the extent that the ongoing Infrastructure Ontario process determines the technology to be used for new nuclear development in Ontario. Were future nuclear developments to be selected based on a competition overseen by OPA, with OPA contracts awarded as a result, the new nuclear generation would not be part of the prescribed asset portfolio, notwithstanding the fact that certain development costs are recovered through the variance and deferral account structure.

4 Characteristics and risk profile of other possible benchmark entities

In the previous section, we have listed a wide range of potential risks along with the unique arrangements established to deal with some of them. In addition, we have laid out conceptually how such arrangements and risks affect whether the OPG prescribed assets are more or less "attractive", "stable", or "certain" relative to two other types of power sector investments: Ontario regulated wires companies, and merchant generators. For many of these entities, capital structure and allowed returns to equity are known, or can be inferred. Below, we highlight returns and capital structures for various kinds of power sector investments. In the subsequent section, we synthesize our findings regarding relative risk of the prescribed assets and the observed allowed returns to power sector entities so as to place the prescribed assets in a risk-reward continuum.

4.1 Canadian entities

We reviewed several different types of Canadian power sector entities. These included other Canadian provincially-owned entities, private Canadian utilities and independent power companies, and Canadian generation focused income trusts. For the sake of comparison, we examined not only treatment of Hydro One, but also of selected US wires-only companies.

4.1.1 other Canadian provincially-owned vertically integrated power entities

LEI examined six vertically integrated Canadian utilities.[51] Further details regarding each of these entities are presented in Appendix A. However, as can be observed, the overall allowed average return on equity is over 9%, and the deemed debt to capitalization ratios are over 65%. It is worth observing that none of these entities is directly comparable to OPG's prescribed assets. Most are vertically integrated, and in some cases the allowed ROE is largely or entirely based on wires assets. Generally speaking, a generation-only entity can be presumed to be more risky than a vertically integrated utility, which is in turn more risky than a wires only company. Furthermore, the generation mix of the prescribed assets differs from that of many of the companies examined here. Arguably, the generation mix of the prescribed assets, due to the presence of nuclear, is more risky than that of BC Hydro, Manitoba Hydro, and Hydro Quebec (Hydro Quebec's nuclear station is smaller relative to total capacity), but less so than SaskPower and the Atlantic Province companies due to the lack of coal and oil-fired assets [which increase risks related to future emissions regulation] among the prescribed assets.

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[51] ATCO Electric is excluded from this list, as its generation assets are no longer part of ratebase.

Figure 13. Canadian provincially-owned vertically integrated power entities[52]							
Province	**Entity**	**Total capacity (MW)**	**% nuclear**	**% hydro**	**Deemed debt to capital**	**allowed return on equity**	
Quebec	Hydro-Quebec TransÉnergie	35,647	1.9%	93.4%	70%	7.50%	T
	Hydro-Quebec Distribution				65%	7.57%	D
British Columbia	BC Hydro	11,323	-	90.4%	70%	13.10%	
Manitoba	Manitoba Hydro	5,461	-	91.4%	75%		
Saskatchewan	SaskPower	3,214	-	26.6%	60%	8.50%	
Newfoundland&Labrador	Newfoundland Power	139	-	68.8%	55%	8.95%	
New Brunswick	NB Power	3,948	16.1%	22.4%	65%	9.50%	T
		9,955	9.00%	65.50%	66%	9.19%	
Ontario		**22,151**	**30.0%**	**31.5%**	**55.0%**	**5.00%**	
					42.5%	**10.50%**	

Sources: most recent annual reports; provincial regulatory authorities for allowed return on equity
Note: T=allowed return on equity for transmission services, D= allowed return on equity for distribution services

4.1.2 Canadian generation-focused income trusts

Many practitioners, when seeking generation comparators, overlook Canada's generation income trust sector. Not withstanding the fact that recent changes in federal tax law will largely eliminate the benefits from the income trust pass-through structure, income trusts may well be securities that are similar to the prescribed assets in attractiveness, certainty of returns, and stability. Indeed, the prescribed assets themselves would have been strong candidates to become income trusts had the provincial government been so inclined.

Figure 14. Canadian hydro generation-focused income trusts						
Name	**Total capacity**	**% nuclear**	**% hydro**	**Debt to capital**	**Avg. annual total returns to shareholders**	**Avg. annual return on equity**
				Bloomberg	Bloomberg	Bloomberg
Great Lakes Hydro Income Fund	1,015	-	100%	57.39%	17.68%	8.18%
OPG (present)	**22,151**	**30.0%**	**31.5%**	**55% (deemed)**		
OPG (applied)				**43% (deemed)**		

Sources: Data for the period 2000 – 2007. Bloomberg; Great Lakes Hydro website

A number of the income trusts have a high proportion of hydro in their portfolios, some of which is under contracts of varying lengths. The stability of such portfolios can enable some income trusts to increase their leverage. The income trusts' portfolios are generally smaller than

[52] Allowed return on equity varies in most cases based on a formula; shown as a fixed number for the convenience of readers. Alberta is excluded as it was not one of the provinces LEI was asked to consider; however, allowed ROEs and debt to capital ratios for Alberta would fall within the midrange of those listed here.

OPG's prescribed assets, and more geographically dispersed. The larger size of the prescribed asset portfolio, and the diversification of technologies, mean that OPG's prescribed assets face slightly less business risk than the income trusts.[53] This is particularly true when variance and deferral accounts are taken into account, as generation income trusts do not have the ability to benefit from similar provisions.

For the sake of comparison, we have focused on the income trust with the largest hydro portfolio, Great Lakes Hydro Income Fund. Debt to capital for Great Lakes Hydro Income Fund is approaching 60%, and its ROE as reported by Bloomberg exceeds 8%.

4.1.3 Hydro One

Hydro One's rates are set on the basis of $/kW, with charging determinants (kW) based on Hydro One's annual forecast of monthly peak demand (or more specifically, higher of the coincident peak and 85% of the customers' peak demand at the time of system peak). Since rates are set based on forecast volume, Hydro One is exposed to some volume risk. However, technically, with the exception of the adjustments for conservation and demand management (CDM) and bypass as discussed below, Hydro One is exposed to volume risk due to varying weather patterns. However, one could argue that the approach for setting rates, whereby Hydro One forecasts a future year's peak demand, allows for some implicit risk mitigation by Hydro One.

Until 2006, Hydro One had an earnings sharing mechanism (ESM), with 50/50 sharing if returns exceeded 9.88%. In 2007, once the ESM ended, the Board approved a tracking account that tracks and accumulates differences in actual revenue and approved revenue.[54] In addition, the transmission rate design established by the Board is intended to mitigate uneconomic bypass and lost revenues due to CDM. Compensation in the case of bypass is done on a case-by-case basis. The Board determines the amount of compensation based on the Net Book Value (NBV) of the stranded asset in question, plus adjustments for salvage and removal costs.

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[53] This conclusion assumes that any additional risk premium associated with nuclear assets is offset by the overall diversification based on number of stations and differing technologies; other observers may place greater weight on the geographic diversity factor in determining relative risk.

[54] The 2007 Revenue Deficiency Deferral Account (RDDA) will record the revenue deficiency between the OEB approved revenue for 2007 compared to 'forecasted' revenue at currently approved transmission rates. Hydro One, in its March 13, 2007 submissions, stated that the EB-2005-0501 transmission earnings sharing mechanism (ESM) was intended to end once new transmission rates were implemented. Hydro One claimed that the proposed RDDA was more transparent than the ESM, and would be easier to justify and implement for a portion of a year (as un-audited financial results would be used.) The RDDA tracks on a monthly basis, the deficiency between the proposed revenue 2007 requirement (per the Hydro One Transmission rate filing) and revenue calculated using current approved rates (by applying a weather normal monthly load forecast consistent with the 2007 load forecast). The differences would be reflected in the deferral account. Monthly carrying costs would be applied to this entry using the short-term interest rate included in the 2007 revenue requirement. OEB approved the RDDA effective January 1, 2007. Disposition of the account would be subject to future OEB review and approval.

There are also variance accounts[55] set up for various policy-level and government initiatives, like smart meter initiatives, and retail settlement. In its 2006-2007 rate application, Hydro One requested additional variance accounts, some of which were approved recently by OEB. Tab 2 Schedule 1 of the 2006-2007 Rate Application notes that "Hydro One also seeks approval of variance accounts to track the impact of tax rate changes (OEB approved), incremental OEB costs (OEB approved), variances between Hydro One's planned and actual pension costs (OEB approved), the amounts paid to third parties as a result of changes to the Transmission System Code between rate re-sets (OEB approved), and the deficiency in 2007 revenues, given the anticipated time to obtain a rate adjustment (OEB approved)."

Hydro One faces the same risks as other regulated utilities related to operations and maintenance and capital expenditures – will it be allowed by the regulator? – although its experts have tried to claim that Hydro One's risks on these fronts are greater in the future because of capital pressures.

> "All costs incurred are subject to a test of prudency; there is no guarantee that all costs of development and construction will be recoverable from ratepayers. Since major projects will likely be undertaken without prior approval of the costs (as has been the case with the Niagara Reinforcement project), Tx faces the risk of delayed recovery of costs (through inclusion in the rate base) as well as the risk of cost disallowances. While these risks are not new or unique, they are amplified by the extraordinary level of capital expenditures faced by Tx."[56]

Based on recent history with distribution rebasing rate cases, OEB has not approached the issue of prudence lightly.

Overall, several of the risks faced by Hydro One are similar to those faced by OPG's prescribed assets, and are dealt with in a similar fashion. Just as the prescribed assets benefit from variance accounts associated with fluctuations in hydrology, Hydro One benefits from the various measures which reduce the burden of CDM. While both the prescribed assets and Hydro One are exposed to fluctuations in demand, this is less the case for the prescribed assets due to their position in the merit order. However, overall our view is that given the higher probability of generation outages than wires outages, and the risk of prolonged nuclear outages, the prescribed assets face slightly higher business risk than Hydro One.

4.1.4 US and UK wires only entities

There has been ongoing debate in Ontario regarding the relevance of US benchmarks for ROEs. Many intervenors have noted that US allowed ROEs are higher than those in Canada, and have presumed that this may be evidence that allowed ROEs in Canada are too low. Such analysis

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[55] For example, Retail Settlement Variance Accounts, Pre-Market Opening Energy Variance Account, Retail Cost Variance Accounts, and Miscellaneous Deferred Debits.

[56] See page 12 of the Foster Associates weighted average cost of capital study prepared as part of Hydro One's 2006-2007 rate filing.

overlooks several factors. US allowed ROEs can vary regionally by as much as 500 basis points; this suggests that even within the US there is little consensus on what the appropriate allowed return should be. Second, many of the higher allowed ROEs are artifacts of earlier rate cases which have yet to be updated; were such rates to be automatically adjusted as is the norm in Canada, ROEs in the US would also have fallen. Third, and perhaps most important, higher ROEs than are necessary to attract capital in the US simply result in transfers from ratepayers to shareholders. As interest rates fall, utility share prices adjust to reflect investor's actual required returns; indeed, acquisitions of regulated utilities at a premium to book value suggest that, while some premium may be justified by increased efficiencies, a portion of the premium simply reflects the fact that new owners are willing to accept a potentially lower return on equity than is provided for in the regulatory accounts.

Figure 15. US and UK wires only companies

Name	**Actual debt to capital ratio** Bloomberg	**Deemed debt to capital ratio**	**Allowed return on equity**	
CH Energy Group, Inc.	45.00%	55.00%	9.60%	Central Hudson
Consolidated Edison Inc.	49.87%	52.02%	9.10%	ConEdison of New York
Energy East	56.01%	58.40%	9.55%	NY State Electric & Gas
			12.25%	Rochester Gas & Electric
			11.40%	Central Maine Power (Transmission)
NSTAR	64.13%		11.40%	NSTAR (Transmission)
Pepco Holdings, Inc.	57.12%	53.45%	10.00%	Pepco (District of Columbia)
			10.00%	Pepco & Delmarva (Maryland)
UI Holding Corporation	56.32%	52.00%	9.75%	United Illuminating
			11.40%	United Illuminating (Transmission)
Unitil	63.67%		8.70%	Unitil Energy Systems
		55.70%	10.25%	Fitchburg Gas&Electric Light
Average	56.02%	54.43%	**10.3%**	
Total average	56.02%	54.43%	**10.3%**	
OPG (present)			**5.0%**	
OPG (applied)			**10.5%**	
Hydro One		60.0%	8.35%	Transmission
		60.0%	9.00%	Distribution
OFGEM (UK)		60.0%	7.0%	Transmission (post-tax real)
		57.5%	7.5%	Distribution (post-tax real)

Sources: Bloomberg; allowed return on equity obtained from state regulatory authorities; OFGEM[57]
Note: OFGEM figures for the UK would need to be adjusted for inflation to be directly comparable to US cost of equity numbers; however, doing so would nonetheless result in lower numbers than many of the wires companies shown above.

It is striking that while experts rightly point out the increasing globalization of investment, and particularly the increased options for Canadians to invest overseas, their analysis seldom extends beyond the US. However, Canadians also invest non-trivial amounts in the United

[57] OFGEM, Transmission Price Control Review, p. 1, December 4, 2006, 206/06; Electricity Distribution Price Control Review, p.3, November 2004, 265/04.

Kingdom, where allowed returns to wires companies are much lower. Overall, our view is that while the business risks faced by the prescribed assets are greater than those faced by US (and UK) wires companies, it would be more appropriate for the OEB to focus on setting the ROE for the prescribed assets relative to Hydro One, rather than placing much weight on values from wires companies (or integrated utilities, discussed later) in the US.

4.1.5 comparison with OPA contracts

Generators built under contract in response to requests for proposals from OPA face significantly higher business risks than do the prescribed assets. Contract holders do not have the ability to recover cost overruns, are not able to pass through changes in pension costs, cannot change prices in response to rising operations and maintenance costs, and are fully at risk for the cost of construction delays, subject to some force majeure exceptions. While the OPA contracts and the prescribed assets share certain characteristics, such as bonus features linked to market prices, and are alike in terms of facing limited counterparty credit risk, overall the OPA contracts assign a greater degree of risk to plant owners than the prescribed asset arrangements do to OPG.

For the most part the RFP contracts exhibit a high degree of structural continuity across the process, soliciting generation projects under 20-year contracts with a single buyer structure (OPA). The mandated commercial operation dates have generally been three years from the announcement of RFP winners in the case of the renewables projects, four years in the case of the CES projects, and 2.5 years in the case of the demand-response projects.

Contract terms and conditions are generally similar for all generation projects, regardless of size, and exhibit similar degrees of complexity. Contracts for the larger new clean power generation projects contain a payment structure based on contingent support and revenue sharing payments, while the renewables contracts call for contract price multiplied by delivered energy terms.

The contracts contain several provisions which increase risks to developers relative to those faced by OPG's prescribed assets. For example, contracts base payments on a deemed dispatch schedule; if plants fail to operate during periods when they are deemed to have done so, they are not eligible for contingent support payments. By contrast, if OPG is successful in obtaining a fixed payment for a portion the nuclear revenue requirement, no such deemed dispatch expectation would apply – the fixed payment would not be clawed back if the plants did not operate. OPA contracts also provide for developers to pay liquidated damages if certain contract terms are not met; OPG is under no such strictures with regards to the prescribed assets. In addition, developers assume significant pre-construction risks and are at risk for cost overruns.

All the contracts contain the same anti-collusion conditions. OPA retention of ownership title to the environmental attributes of renewables generation assets is also common to all RFP contracts. Finally, the credit and security requirements for the renewables RFP contracts are similar across projects, while the requirements are, as expected, somewhat higher for larger new clean power generation contracts. Figure 16 on the following page provides some information on the RFP contract terms and conditions.

Figure 16: Selected RFP contract terms

	Renewables I	Renewables II	Renewables III [draft contract]	Consolidated 2500 MW CES, DSM, DR
Payment terms	1.contract price x monthly delivered electricity 2."constrained on" payment provision 3. above-cap energy provision 4. buyer's share: 50% of above-cap energy 5. operating reserve payment 6. performance incentive payment 7. approved incremental costs	same terms as Renewables I with these exceptions: 1. no operating reserve provisions 2. provision for the Buyer's return to the Supplier of 15% of the sale of contract-related products	same terms as Renewables II	Contingent Support payment from Buyer to Supplier; Revenue Sharing Payment from Supplier to Buyer
Environmental Attributes	buyer retains	same terms as Renewables I	same terms as Renewables I	same terms as Renewables I
Credit & Security Requrements	$33,000/MW until operational date; then $20,000/MW	$33,000/MW until operational date; then $20,000/MW -- provisions for adjusting security in case of altered contract capacity	$33,000/MW until operational date; then $20,000/MW -- provisions for adjusting security in case of altered contract capacity	$100,000/MW if commercial op. before Dec. 31, 2006; $70,000/MW if commercial op. b/n Dec. 31, 2006 and Dec. 31, 2007; $50,000/MW if commercial op. is on or after Dec. 31, 2007
Credit Evaluation	S x T S = net worth in dollars T = scale from 0.05 (S&P BBB- rating) to 0.10 (S&P A- rating)	same terms as Renewables I	same terms as Renewables I	same terms as Renewables I
Performance Incentive Payments	P x (Q-R) x S P = 25% Q = production-weighted avg. price S = monthly delivered power R = time-average price P = 25%	same terms as Renewables I	same terms as Renewables I	no
Anti-Collusion Conditions	yes	yes	yes	yes
Capacity Adjustment Option	yes	yes	yes	yes
Milestone Date Penalties	$65/MW x contract capacity per day Maximum $33,000/MW x contract capacity	same terms as Renewables I	same terms as Renewables I	same terms as Renewables I
Contract Indexation	15% indexed; 85% non-indexed	same terms as Renewables I	same terms as Renewables I	Energy Cost, Startup Cost, and O&M Cost are indexed

4.2 US entities

Utilities in the US take on a wide array of institutional forms. In addition to investor-owned utilities, which can be wires-only or vertically integrated, there are federal power authorities (largely generation and transmission), state agencies (often more weighted towards generation), municipal utilities, and co-operatives. Below, we briefly review issues related to capitalization, returns, and relative risks of these entities.

4.2.1 US Federal power entities

There are a number of types of Federal power entities in the United States.[58] Most are largely self-regulating, and set rates at levels that assure debt repayment. Although debt issued by these entities is not equivalent to US Government bonds, investors perceive an implied guarantee, allowing some power authorities to be almost entirely debt financed. Any equity which arises is a result of debt repayments, and new debt issuances can be used to maintain a very low equity base. The appendix goes into greater detail about these entities.

Figure 17. Selected US Federal power entities[59]

Name	Region	Total capacity	% nuclear	% hydro	Debt to capital	Comments
TVA	Southeast	33,410	20.6%	15.5%	91.0%	rates set by the TVA board under regulation of TVA Act; cost-based rate setting
BPA	Pacific Northwest	-	-	-	88.0%	rates set under regulation of Pacific Northwest Elelctric Power Act; cost-based rate setting
average		33,410	20.60%	15.50%	89.50%	
OPG (present)	**Ontario**	**22,151**	**30.0%**	**31.5%**	**55.0%**	
OPG (applied)					**42.5%**	

Sources: most recent annual reports

While there are some similarities in the underlying assets (Tennessee Valley Authority, or TVA, for example, has substantial hydro assets, as well as a large nuclear fleet in which some units are being refurbished), the federal power authorities are not perfect analogues to the prescribed assets. Unlike OPG, the federal power authorities are not fully corporatized, and do not operate as normal commercial organizations. Crucially, they also face low regulatory risk – they are not subject to rate regulation by state commissions, and the Federal Energy Regulatory Commission (FERC) has limited oversight of these entities. The federal power authorities bear a greater

[58] In addition to Bonneville Power Administration, there are the Southeastern, Southwestern, and Western Area Power Administrations, for example. Multi-state (but non-Federal) public entities include organizations like the Salt River Project, which are both water and power providers.

[59] Bonneville Power Administration (BPA) markets power from 31 federal dams, one non-federal nuclear plant, and some non-federal wind and other generating stations.

resemblance to the former Ontario Hydro than to the prescribed assets.[60] While the federal power authorities demonstrate that higher levels of debt can be achieved in their capital structures, this higher degree of leverage must be viewed in the context of statutory rate setting mechanisms which require rates to be set at a level which will assure that debt is repaid.

In this context, it is worth noting that BPA rates included several Cost Recovery Adjustment Clauses (CRACs) from 2002 through 2006 which provided insurance against revenue volatility. These included load-based, financial based, and "safety net" CRACs. The load-based CRAC allowed BPA to pass through costs of purchased power; the financial based CRAC provided additional revenue in the event of a projected revenue shortfall for reasons other than purchased power costs, and the safety net CRAC was triggered if a scheduled payment to the US government or creditors was missed or expected to be missed. These CRACs have been replaced with a single CRAC which is applied whenever a revenue shortfall is projected; the amount allowed under this consolidated CRAC can be increased to offset various environmental costs, such as protection of fish populations. This adjustment is referred to as the Biological Opinion Rate Adjustment Mechanism.[61]

4.2.2 generation and transmission co-operatives

There are a number of generation and transmission cooperatives in the United States; we consider a sample of them here. Cooperatives are owned by their members; rates are generally cost-based. Few approximate exactly the generation mix of the prescribed assets. Cooperatives vary widely in their degree of sophistication, but generally have the ability to achieve high levels of debt in their capitalization structures. However, cooperatives in the US have been known to go bankrupt or to be substantially restructured. Again, a key difference with the prescribed assets is the fact that co-ops are relatively lightly regulated; this is likely a mixed blessing for ratepayers, in that co-ops face little scrutiny with regards to efficiency or financial stability.

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[60] It is worth noting, however, that the Beck tunnel financing was expected to be based on up to 100% debt financing from the province, similar to the fashion in which the US Federal power entities are able to finance some of their capital projects. See, for example, Standard and Poor's Canadian Ratings, OPG, 12-9-05, p.2.

[61] BPA 2007 Annual Report, p. 28.

Figure 18. Generation and transmission cooperatives

Name	State	Total capacity	% nuclear	% hydro	Debt capital ratio
Oglethorpe Power Corporation	Georgia	4,744	25.0%	13.3%	87%
Basin Electric Power Cooperative	North Dakota	3,710	-	44.5%	63%
East Kentucky Power Cooperative	Kentucky	3,308	-	5.1%	94%
Great River Energy Cooperative	Minnesota	2,816	-	3.5%	85%
South Mississippi Electric Power Association	Mississippi	1,915	65.0%	-	87%
Power South Energy Cooperative	Alabama	1,724	-	0.4%	89%
Arkansas Electric Cooperative Corporation	Arkansas	2,638	-	10.1%	52%
Dairyland Power Coooperative	Wisconsin	1,220	-	2.0%	83%
North Carolina Electric Membership Corporation	North Carolina	662	97.3%	-	97%
average		2,526	62.4%	11.3%	81.9%
OPG (present)	**Ontario**	**22,151**	**30.0%**	**31.5%**	**55.0%**
OPG (applied)					**42.5%**

Sources: most recent annual reports; companies' websites

4.2.3 regulated vertically integrated private utilities

Figure 19. Sample of selected vertically integrated private utilities

Name	Province	Total capacity (MW)	% nuclear	% hydro	Deemed debt to capital ratio	allowed return on equity
Arizona Public Service Co.	Arizona	5,947	19.4%	0.0%	46.0%	10.75%
Detroit Edison Company	Michigan	11,020	10.2%	8.3%	54.0%	11.00%
Duke Energy Carolinas, LLC	North Carolina	19,204	26.1%	16.5%	47.0%	11.00%
Entergy Arkansas Inc.	Arkansas	4,978	38.5%	1.3%	54.5%	9.90%
Florida Power&Light Company	Florida	22,135	13.3%	0.0%	44.2%	11.75%
Georgia Power Company	Geogia	15,995	12.2%	6.8%		11.25%
PacifiCorp	Washington	712	0.0%	73.0%	53.0%	10.20%
Portland General Electric	Oregon	2,315	0.0%	22.1%	50.0%	10.10%
Public Service Co. of Colorado	Colorado	4,290	0.0%	7.8%	40.0%	10.50%
Puget Sound Energy	Washington	1,984	0.0%	13.3%	50.7%	10.40%
average		8,858	11.97%	14.91%	48.82%	10.69%
OPG (present)	**Ontario**	**22,151**	**30.0%**	**31.5%**	**55.0%**	**5.0%**
OPG (applied)					**42.5%**	**10.5%**

Sources: most recent annual reports; SEC Form 10-K filings; State regulatory authorities

Although potentially subject to less political interference[62] than OPG, regulated vertically integrated utilities in the US share with OPG a commercial orientation, as well as similarly structured rate recovery mechanisms. Bundling of generation with wires assets means that vertically integrated utilities are, on par, less risky than the OPG prescribed assets; even given the number of variance and deferral accounts proposed by OPG, inclusion of the less risky wires asset class with generation makes vertically integrated utilities less risky than OPG. Indeed, many vertically integrated utilities have similar sets of variance and deferral accounts associated with their generation assets.

However, even though we find the OPG assets more risky than those of regulated vertically integrated utilities, our concerns about the appropriateness of allowed returns in the US continue to apply. We are not convinced that awarding a higher allowed ROE to the prescribed assets than a similarly situated US utility is appropriate, and note that if a higher ROE is offered, it should only be in the context of higher proportion of debt financing in the capital structure as well. Note that many of the US utilities listed in the table above also have a portfolio which includes other types of generation assets than hydro and nuclear; the presence of such assets may increase risk given their greater marginal costs and less favorable environmental characteristics.

4.2.4 merchant generators

The last set of power sector assets we will consider is merchant generators. As previously defined, merchant generators derive the bulk of their profits from the sale of energy in a mix of spot and contract markets. None of their generation is under ratebase, though power purchase agreements may serve to mitigate some risks. As a group, merchant generators are not homogenous; some, like AES, also own distribution assets, and the geographic spread and technology mix varies among companies. Three of the companies listed below went through bankruptcy; statistics shown tend to mute risk by only considering performance of new shares issued after exit from bankruptcy. Given this, the risk of the sector on a historical basis is likely greater than an examination of recent betas would imply.

[62] US states vary widely in the extent to which state governments have the authority to intervene in electricity markets. State regulatory commissions generally have a greater degree of autonomy from state governments then do Canadian regulatory bodies. Even in the cases of Illinois and Maryland, state government intervention was triggered by a limited set of issues, and does not show a tendency for repeated short term interventions on a wide range of regulatory issues. Furthermore, US state governments do not have the ability to issue directives to the companies established on a commercial basis in their state to make particular investments at less than commercial rates of return.

Figure 20. Merchant generators

Name	Capacity MW	Levered Beta	Debt to capital
source:		*Bloomberg*	*balance sheet*
AES Corporation	43,000	0.97	81.4%
Calpine Corporation	23,809	0.93	62.1%
Canadian Hydro	364	0.55	49.3%
Dynegy	19,165	1.19	65.7%
International Power	18,935	1.07	74.4%
Mirant	10,280	0.92	43.8%
NRG Energy, Inc.	24,115	1.00	76.1%
Ormat Technologies	400	1.21	46.4%
Reliant Energy, Inc.	16,337	1.17	52.7%
Transalta	8,877	0.75	61.1%
average		0.98	61.3%
OPG (present)			**55.0%**
OPG (applied)			**42.5%**

Sources:
Bloomberg; debt to capital based most recent annual SEC Form 10-K filings as downloaded from Bloomberg except for Calpine as explained below.
Notes:
Calculations based on use the difference between total assets and shareholder equity divided by total assets; thus, total debt D = total assets A minus shareholder equity E; debt to capital equals D/A. This calculation incorporates both short term and long term debt into the calculation.
Aggregate value of Calpine's PPAs is USD 1.5 billion, as of December 31, 2007. Debt to capital for Calpine is estimated based on structure of post-bankruptcy company; Calpine exited bankruptcy in January 2008.
Most of the companies listed above have a degree of contract cover of varying lengths ranging from 50% to 100%.

Overall, merchant generators face greater business risk than the prescribed assets – their counterparty credit risk is greater, their exposure to commodity price risk is greater, in some cases the companies are highly exposed to potential climate change regulatory risk, and none of these companies can rely on variance or deferral accounts to smooth revenues or to recover unsuccessful business development costs. Nonetheless, on average they have been able to achieve higher leverage than that proposed by OPG for the prescribed assets; indeed, TransAlta has been recently the target of shareholder pressure to increase its leverage.

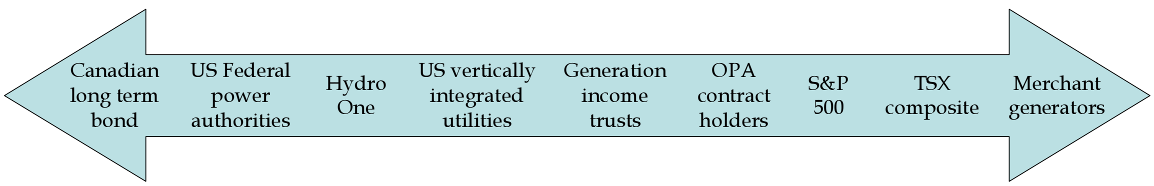
5 Risk of prescribed assets relative to potential benchmark assets

5.1 other asset classes to consider

To fully develop the universe of investment alternatives to the prescribed assets, we also considered long term Canadian government bonds, the Toronto Stock Exchange (TSX) composite index, and the Standard and Poor's (S&P) 500. The yield on the benchmark Canadian 30 year bond has averaged 6.4% since 1990. Over the same period, average annual returns on the TSX composite have been 9.98% per year[63] while average annual returns on the S&P 500 have been 11.91% per year. Generally speaking, we would regard the prescribed assets as being more risky than Canadian long bonds, but less so than either the TSX composite or the S&P 500.

5.2 examining placement of various power sector and alternative asset classes on an indicative relative risk spectrum

Figure 21. Indicative assessment of relative risk of various asset classes[64]



We have developed an indicative continuum of relative risks of various asset classes. OPG's prescribed assets can be placed at various points on this continuum depending upon analyst views on various risk factors. The above continuum may not be consistent with an ordinal ranking based on observed ROEs. However, we believe it is consistent with an assessment of the relative volatility of returns, and the degree to which investors in the assets listed receive full or partial hedges from regulatory arrangements or long term contracts. We also believe that the above continuum can also be used to determine the ability to carry debt; moving from left to right, the ability to raise large amounts of debt diminishes as the volatility of net revenues increases.

Placing the prescribed assets on a risk continuum requires an assessment of a number of issues, many related to determining the extent to which net income volatility is unpredictable and unhedged. In assessing "attractiveness", "stability", and "certainty" of the profits to the prescribed assets relative to other asset classes, observers need to think systematically about the risk factors and mitigants discussed in this paper (and such others as may be appropriate) and

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[63] Bloomberg, April 15th, 2008.

[64] This chart is not intended to be to scale; we do not regard the asset bundles to be equally spaced along a risk continuum.

determine whether, when considered collectively, such risk factors lead to more or less profit volatility than can be observed for other asset classes.

Throughout this paper, we have provided an assessment of the directional impact various risk factors have on required equity returns and ability to increase debt in an optimal capital structure. We believe that a number of objective observations can be made to assist in positioning the prescribed assets on the continuum:

- ***ownership of OPG*** – use of this factor to assess risk can only be taken into account to the extent that regulators also differentiate between the types of owners of other OBCA corporations;
- ***appropriateness of the "stand alone" principle*** – given that many other entities regulated by the OEB have both regulated and unregulated assets, it would be anomalous to incorporate consideration of the non-prescribed assets into risk assessments for the prescribed assets unless this is also done for other regulated entities with non-regulated subsidiaries;
- ***effect of ONFA*** – to assess risk of the prescribed assets relative to owners of nuclear assets elsewhere in Canada and the US, the extent of the limits of financial liability in the ONFA can be compared directly to the limits which arise from the Price-Anderson Act, decommissioning fund structures, and US nuclear fuel reprocessing levies. The extent to which OPG faces more or less uncertainty surrounding its obligations can to some degree be quantified, and to the extent that the ONFA reduces risk relative to other nuclear entities for which the ROE is known, the allowed ROE for the prescribed assets may be less;
- ***reliance on OEFC*** – as noted above, this effect is directly quantifiable; to the extent that the reduction in borrowing costs is greater than any guarantee and arranging fees paid, the benefits can be quantified; this benefit can be directly compared to, for example, US Federal power entities to determine whether implied borrowing costs are higher or lower;
- ***portfolio composition*** – profit volatility based on the proposed arrangements and the asset types can be directly observed and compared to the volatility of profits for merchant generators and publicly traded utilities and their regulated subsidiaries; comparing profit volatility based on the prescribed asset portfolio mix would allow for an understanding of whether the prescribed assets are more or less risky;
- ***timing and nature of rate review*** – this risk factor should diminish over time as greater precedence is set; to the extent that this becomes more predictable, and the cycle and content of reviews known, this content and timing can be compared to other rate regulated entities to assess relative "certainty" and "stability";
- ***variance and deferral accounts*** – the presence and nature of these accounts has a direct impact on the stability of profits to OPG; assessing the degree to which entities on the risk continuum benefit from similar structures helps determine the appropriate return;
- ***fixed monthly payments for nuclear*** – the fixed monthly payments increase certainty of cash flows, and potentially profits; an assessment of the extent to which various types of

entities receive fixed payments regardless of performance can position OPG's prescribed assets on the risk continuum;[65]

- ***impact of assets being fully regulated*** – this element also affects the certainty of returns; in theory, the greater proportion of unregulated assets in a portfolio, the lower the certainty of returns, provided the regulator is credible;
- ***bonus revenues*** – bonus revenues contribute to the relative attractiveness of the assets; regulated assets without the potential to earn upside through improved performance are clearly less attractive than those that do have such potential;
- ***dispatch risk*** – dispatch risk is quantifiable, and can be compared to other generation portfolios; by analogy, it can also be compared to network utilization rates, and for other industries, to positioning between low and high cost producers;
- ***nuclear outage risk*** – outage risks can be quantified based on experience; the expected impact on the volatility of profits for the prescribed assets can also be modeled; this volatility can be compared to the volatility of profits for other asset classes;
- ***counterparty credit risk*** – again, this is fairly straightforward to assess; indeed, bad debt expense can be compared across entities to determine the relative risk;
- ***impact of changes in air emission regulations*** – simply by listing the assets affected by changes in air emissions regulations, and determining the contribution of those assets to the entity's profits, the risk relative to the prescribed assets can be determined; an oil sands producer, for example, would clearly be at greater risk from emissions regulations than would the prescribed assets;
- ***political risk*** – this is among the most difficult of the risk factors to quantify; third party providers of political risk scores seldom do so at a state or provincial level. Possible approaches would include determining the number of relevant policy changes per year per jurisdiction, or the number of changes of government over a particular period in time.

5.3 creating a framework for future adjustments to OPG's capital structure and allowed return on equity

The above section reviewed the various identified risk factors and discussed how each could be used to determine risk relative to other asset classes. Two approaches are possible to convert this list into a framework. One would be to rank the OPG prescribed assets in each risk category relative to the other identified asset classes, and then to average the ranks; using the average rank for the OPG prescribed assets, OPG's place on the risk continuum can be determined. An alternative approach would be to observe the volatility of profits associated with OPG's prescribed assets directly, and to compare this volatility with other asset classes to

[65] LEI's work worldwide suggests that the large majority of regulated electric utilities receive a disproportionate amount of their revenues through volumetric, rather than fixed, charges. This is true for many Ontario wires companies as well. OPG's claims in its submission on this issue are somewhat distinct from observed experience.

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determine relative attractiveness, certainty, and stability. The latter approach, though less subjective, relies on what is currently a limited data set; backcasting would be required in order to attain a longer historical data series. Such backcasting may ultimately be as subjective as the ranking exercise proposed as the first approach.

While we were not asked to develop a specific numeric formula whereby rates would be adjusted, or to position the prescribed assets on the risk continuum ourselves, it is nonetheless possible to make some broad observations about how allowed returns should change under particular conditions:

- as variance and deferral accounts are removed, a higher allowed ROE can be justified;
- were the nuclear and hydro assets to be considered separately, a higher allowed ROE for the nuclear assets relative to the hydro assets would be justified; and
- increasing the duration of the regulatory period would justify an increase in the allowed ROE, which could be coupled with an ESM.

We continue to believe that development of a longer term formulaic approach to regulation of the prescribed assets would be beneficial to all parties, though appropriate periodic information filings and a set of off-ramps may be necessary.

6 Concluding remarks and summary of opinions

LEI was not engaged to perform a quantitative analysis to develop a precise estimate of either the appropriate return or capital structure for the prescribed assets. Instead, in keeping with Alfred Kahn's "zone of reasonableness", we were asked to assess risks associated with the OPG prescribed assets, and to determine how such risk compared with other possible benchmark assets. The qualitative, "common sense" nature of this analysis does not mean that the findings are less valid than those based on extensive quantitative analysis. Indeed, sophisticated statistical methods to determine the cost of capital often serve to obscure the degree of subjectivity involved in some of the assumptions used, particularly with regards to market equity risk premiums and appropriate calculation of betas.

Overall, our findings are as follows:

- the intended role of the regulated payments for the prescribed assets is to manage risk (i.e., reduce volatility) for both OPG as seller and customers as buyers, while at the same time providing an appropriate commercial return to OPG;

- based on an assessment of forced outages, generation assets (even with regulated payment streams) would appear to be slightly more risky than regulated network companies, which all things being equal would justify a higher allowed equity return;

- current arrangements surrounding the prescribed assets serve to reduce risk significantly relative to other merchant generation companies, meaning that allowed returns to equity associated with the prescribed assets should also, logically, be lower than those derived for merchant generators using the capital assets pricing model;

- the OPG prescribed assets are relatively less risky than generators with contracts from the OPA, and should be able to sustain at least as much, if not more, debt in their capital structure, and

- appropriate capitalization structures should be based primarily on criteria used by credit rating agencies and lenders such as debt service coverage ratios; the potential overall long run stability of the cashflows associated with the prescribed assets may allow for a more efficient capital structure, including a higher proportion of debt, than that proposed by OPG.

While alternative arrangements for the prescribed assets may result in better incentives compatibility, and thus greater benefits for customers and for OPG, to the extent that the arrangements proposed by OPG are adopted an appropriate calculation of the cost of capital is key. Failure to do so may result in distorted investment and operational decisions, to the long term detriment of ratepayers.

7 Appendix A: detailed snapshots of selected Canadian utilities

7.1 Hydro-Quebec

Hydro-Quebec is a public vertically integrated utility, supplying electricity to industry, business and residential customers across Quebec. The Corporation consists of four divisions: Hydro-Quebec Production generates electricity, supplies its output to its subsidiary Hydro-Quebec Distribution at fixed regulated prices, and sells excess electricity on the wholesale market both inside and outside Quebec. Hydro-Quebec TransEnergie operates the transmission system covering the Province of Quebec. Hydro-Quebec Distribution is responsible for supplying Quebecers with electricity provided by Hydro-Quebec Production. Hydro-Quebec Equipment is Hydro Quebec's prime contractor for constructing projects.

Figure 22. Hydro-Quebec operational statistics 2007

Generation capacity (MW)		**Share (%)**
Hydro	33,305	93.4
Nuclear	675	1.9
Thermal	1,665	4.7
Wind	2	0.01
Total	35,647	
Peak demand (MW)	35,352	
Transmission grid	32,826	km
Total customers accounts (in thousands)	3,869	

Source: Hydro-Quebec Annual Report 2007[66]

7.1.1 Return on equity, capital structure and credit ratings

The Quebec regulatory commission Regie de l'energie du Quebec ("Regie") set Hydro Quebec TransEnergie's return on equity (ROE) for 2007 at 7.5%, assuming a capital structure with 30% equity.[67] The authorized ROE for Hydro Quebec Distribution for 2007 was set at 7.57%, assuming a capital structure with 35% equity.[68]

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66 Annual Report 2007, Hydro-Quebec, provided by Hydro-Quebec, p. 101, http://www.hydroquebec.com/publications/en/annual_report/2007/index.html.

67 Rate Decision D-2007-34, Regie de l'energie, http://www.regie-energie.qc.ca/audiences/2007.htm.

68 Rate Decision D-2007-12, Regie de l'energie, http://www.regie-energie.qc.ca/audiences/2007.htm.

Figure 23. Hydro Quebec consolidated financial results 2007 (million CAD where applicable)		
Total Assets	64,852	
Deemed debt to capital ratio - Trans.	70%	
Deemed debt to capital ratio - Dist.	65%	
Allowed ROE - Trans.	7.50%	
Allowed ROE - Dist.	7.57%	
Credit ratings	**Long-term debt**	**Short-term debt**
Standard&Poor's	A+	A-1+
Moody's	Aa2 stable	P-1
Fitch	AA- stable	F1+
Dominion Bond Rating Service	A (high) stable	R-1 (middle)

Source: Hydro-Quebec Annual Report 2007[69]

7.1.2 Regulatory framework

Quebec's electricity market is regulated by the Act respecting the Regie de l'energie which grants the Quebec regulatory commission Regie de l'energie du Quebec the authority to fix rates for the transmission and distribution of electric power in Quebec.[70] The Act stipulates that rates are determined on a basis that allows for recovery of the cost of service and a reasonable ROE.

Additionally, the Act mandates Hydro-Quebec Production to supply Hydro Quebec Distribution with a heritage pool that corresponds to the net consumption by Quebec markets.[71] The pool represents an annual level of up to 165 TWh of electricity exclusive of consumption under demand-side management and exports to be supplied to Hydro-Québec Distribution to meet its native load obligation at an average cost of 2.79 Canadian cents per kWh.

There are currently some provisions in place overseeing the internal relationships between the Hydro-Québec entities, primarily with respect to Hydro-Québec Distribution and its power procurement obligation. As mentioned previously, Hydro-Québec Distribution has the obligation to serve native load in Québec. Furthermore, it can draw up to 165 TWh of energy

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69 Annual Report 2007, Hydro-Quebec, provided by Hydro-Quebec, p. 56, 74, 100, 101, http://www.hydroquebec.com/publications/en/annual_report/2007/index.html.

70 Act respecting the Regie de l'energie, updated January 1, 2008, provided by Regie l'energie du Quebec, http://www.regie-energie.qc.ca/en/regie/reglements.html.

71 Act respecting the Regie de l'energie, updated January 1, 2008, P 52.2, provided by Regie l'energie du Quebec, http://www.regie-energie.qc.ca/en/regie/reglements.html.

from Hydro-Québec Production at a price that is capped. To meet load in excess of this "heritage pool", Hydro-Québec Distribution must enter into supply contracts with generators through a competitive procurement process (calls for tenders). In order to determine the amount of new generation that is to be procured, Hydro-Québec Distribution is required to develop a long term supply plan. The supply plan, which is subject to the Régie's approval, presents a load forecast of the Québec market for the next 10 years as well as the nature of the contracts Hydro-Québec Distribution proposes to enter into in order to meet this load above 165 TWh. Hydro-Québec Production is allowed to take part in the call for tenders.

7.1.3 Risk profile

Hydro-Quebec uses an integrated approach to manage its risks. The company's divisions identify and assess principal risks, and then develop mitigation measures. The following risk groups have been identified:[72]

- Financial risks – volatility of exchange rates, interest rates and aluminum prices
- Generation risks – volatility in production
- Credit and market risks related to energy trading on wholesale markets
- Transmission and distribution risks – continuity of transmission and distribution service
- Construction risks – upward pressure on costs of Hydro-Quebec projects
- Other risks – respect and preservation of the environment; information security

7.2 British Columbia Hydro and Power Authority

British Columbia Hydro and Power Authority ("BC Hydro") is the largest electric utility in British Columbia (B.C.), serving approximately 95% of the province's population.[73] BC Hydro's primary business activities are the generation and distribution of electricity. Hydroelectric electricity is the most significant energy source, accounting for approximately 90% of BC Hydro's total installed capacity of 11,414 MW. BC Hydro delivers electricity through its distribution operations. BC Hydro also owns transmission assets, however, the operation of British Columbia's transmission system is the responsibility of the British Columbia Transmission Corporation.

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72 Annual Report 2007, Hydro-Quebec, provided by Hydro-Quebec, p. 69, http://www.hydroquebec.com/publications/en/annual_report/2007/index.html.

73 About BC Hydro, BC Hydro Website, http://www.bchydro.com/info/

Figure 24. BC Hydro operational statistics 2006/07

Generation capacity (MW)		**Share (%)**
Hydro	10,232	90.4
Thermal	1,091	9.6
Total	11,323	
Purchases (MW)	1,500	
Peak demand (MW)	10,113	
Generation (GWh)		**Share (%)**
Hydro	44,476	97.7
Thermal	1,060	2.3
Total	45,536	
Purchased power (GWh)	45,666	
Operating statistics		
Transmission grid	18,280	km
Distribution grid	56,000	km
Total customers (in thousands)	1,737	

Source: BC Hydro Annual Report 2006/07[74]

7.2.1 Return on equity, capital structure and credit ratings

BC Hydro's allowed ROE for 2007 as approved by the British Columbia Utilities Commission (BCUC) was 13.10% (allowed ROE 2006 was 13.51%).[75] As of April 1, 2008, power rates will increase due to increasing revenue requirements based on significant investments in refurbishment and new installations of generation facilities and infrastructure.[76]

74 Annual Report 2006/07, BC Hydro, p. 119, 121, http://www.bchydro.com/info/reports/reports853.html.

75 Negotiated Settlement Agreement, p. 7, filed by BCUC on November 10, 2006, http://www.bcuc.com/OrderDecision.aspx.

76 Electricity tariff BC Hydro, provided by BC Hydro http://www.bchydro.com/policies/rates/rates764.html

Figure 25. BC Hydro financial results 2006/07 (million CAD where applicable)

Total Assets	12,845
Deemed debt to capital ratio	70%
Allowed ROE	13.1%
Credit rating	
Standard & Poors	AAA
Moody's	Aa1

Source: BC Hydro Annual Report 2006/07[77]

7.2.2 Regulatory framework

BC Hydro was established as a Crown Corporation of the Province of BC by enactment of the Hydro and Power Authority Act. BC Hydro is subject to regulation by the BCUC which approves capital spending, electricity purchase agreements, revenue requirements and rates for services provided by BC Hydro. BCUC also sets BC Hydro's allowed ROE and annual payments to the Province of BC. BC Hydro's applications of revenue requirements and rates charged to customers are filed and approved by BCUC.

BC Hydro's power rates are cost-based. Rates are set in order to recover all incurred costs, including debt service, and to earn an appropriate return on invested capital. Additionally, BC Hydro charges a rate rider which is used to pay down BC Hydro's deferral accounts which record unexpected costs and sudden prevent sudden rate fluctuations.

The BC Hydro Public Power Legacy and Heritage Contract Act defined all of BC Hydro's existing integrated generating facilities as Heritage Resources while enabling the establishment of a Heritage Contract. The Heritage Contract established an agreement between BC Hydro's generation line of business and BC Hydro Distribution, including an obligation to supply power at fixed rates.[78] The government of B.C. adopted the Heritage Contract, aiming to ensure that the value of these assets is passed on to customers at embedded costs. The Contract came into effect on April 1, 2004 and will last for 10 years. The government of BC also adopted the BCUC's recommendations for a stepped rates structure which features different rates for different blocks of energy consumption. The cost for electricity supply is calculated by averaging the cost of electricity generated by endowment assets and new generation plants.

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77 Annual Report 2006/07, BC Hydro, p. 117, 118, http://www.bchydro.com/info/reports/reports853.html.

78 Heritage Contract, Appendix A to Heritage Special Direction No. HC2, provided by BCUC, http://www.bcuc.com/SpecialDirection.aspx.

7.2.3 Risk profile

BC Hydro's operations involve a range of risks that could impact the company's business performance. BC Hydro divides its key risks into six categories:[79]

- Employee, public and dam safety – risk group that includes risks associated with BC Hydro's generation and transmission operations in connection with public safety and employee safety
- Reliability – risk group that includes uncertainties related to weather conditions
- Financial performance – risk group reflecting BC Hydro's exposure to variability in energy costs, energy demand, interest rates, exchange rates, and energy trading
- Regulatory risk – includes risks associated with costs incurred through existing and future regulations
- Organizational risks – includes risks related to BC Hydro's aging workforce and general economic conditions
- Environmental and social performance – risk group that includes uncertainties associated with compliance with existing and future environmental and social regulations

7.3 Manitoba Hydro

Manitoba Hydro is a vertically integrated utility owned by the government of the Canadian Province of Manitoba. Manitoba Hydro is the province's largest supplier of energy, providing electricity to 516,800 customers and gas to 259,500 customers throughout Manitoba.[80] The company produces electricity in hydroelectric and thermal power stations and delivers its output through its transmission and distribution system. Additionally, Manitoba Hydro exports electricity to over 30 electric utilities in Canada and the mid-western US.

Manitoba Hydro owns 14 hydroelectric and two thermal power generating facilities across Manitoba. Hydroelectric power accounts for 91% of total capacity. The only two thermal power stations generate electricity based on coal, natural gas and diesel. Total installed capacity stands at 5,461 MW. Manitoba Hydro's five hydroelectric facilities located at Nelson River contribute the great majority of total output (77%). Total generation throughout fiscal year of 2006/07 was 32,144 GWh.

Manitoba Hydro operates and maintains an extensive transmission and distribution system throughout Manitoba. Since the majority of Manitoba Hydro's electricity must travel long distances, Manitoba Hydro operates a number of converter stations which convert alternating

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[79] Annual Report 2006/07, BC Hydro, p.89, http://www.bchydro.com/info/reports/reports853.html.

[80] About Manitoba Hydro, Manitoba Hydro website, http://www.hydro.mb.ca/corporate/about_us.shtml.

current (AC) to direct current (DC) for transmission from northern Manitoba to southern Manitoba and then back to AC for transmission to customers.

Figure 26. Manitoba Hydro operational statistics 2006/07

Generation capacity (MW)		**Share (%)**
Thermal	4,992	91.4%
Hydro	469	8.6%
Total	5,461	
Peak demand (MW)	4,173	
Generation (million kWh)	32,144	
Total customers	776,300	

Source: Manitoba Hydro Annual Report 2006/07[81]

7.3.1 Return on equity, capital structure and credit ratings

Manitoba Hydro is a provincially-owned Crown Corporation. Manitoba Hydro has a deemed debt to capital share of 75%. The consolidated financial results for fiscal year 2006/07 illustrated below include financial statements of Manitoba Hydro and its subsidiaries. The figures in brackets represent results generated by Manitoba Hydro's electricity operations.

Figure 27. Manitoba Hydro financial results 2006/07 (million CAD where applicable)

Total assets	10,964	(10,367)
Deemed debt to capital ratio	75%	
Allowed ROE	N/A	
Credit rating		
Canadian Bond Rating Service	AA	Senior unsecured debt
	A-1H	Short term

Source: Manitoba Hydro Annual Report 2006/07[82]

81 Annual Report 2006/07, Manitoba Hydro, p. 101, published by Manitoba Hydro March 31, 2007, http://www.hydro.mb.ca/corporate/ar/2006/annual_report_2006.shtml.

82 Annual Report 2006/07, Manitoba Hydro, p. 100, published by Manitoba Hydro March 31, 2007, http://www.hydro.mb.ca/corporate/ar/2006/annual_report_2006.shtml.

7.3.2 Regulatory framework

The prices charged for electricity and natural gas within Manitoba are subject to approval by the Public Utilities Board of Manitoba ("Manitoba PUB"). Manitoba PUB's rate setting methodology ensures that rates charged to electricity and gas customers recover costs incurred by Manitoba Hydro. Manitoba Hydro applies a cost of service study to determine the adequacy of annual revenues and fairness of rates between consumer classes. Rates proposed by Manitoba Hydro are then subject to Manitoba PUB's review and approval.

7.3.3 Risk profile

Manitoba Hydro identifies and manages risks through a systematic, integrated process. All risks are assessed for potential impact using financial, safety, reliability, environment, and customer value criteria. As part of Manitoba Hydro's 2008/09 rate application filing, the company identified 11 major risk groups.[83]

- Market risks – risks related to the domestic market, including competition and uneconomic loads, and the export market, including regulation, competition, transmission, special interest groups, protectionism, and commodity availability
- Financial risks – risks reflecting uncertainties related to exchange rates, interest rates, credit condition, inflation, gas price volatility, gas derivative instruments, capital structure, fuel price volatility
- Environmental risks – risks related to water supply, climate change, operational impact and infrastructure
- Infrastructure risks – risks including loss of plant, insufficient supply, prolonged loss of system supply, system shutdowns, technology
- Human risks – risks related to health, safety, unions, succession planning
- Business operational risks – risks reflecting uncertainties related to the company's supply chain and operational controls
- Reputation risks
- Governance/Regulatory/Legal
- Aboriginal related risks including relationship and legal issues
- Alternative technologies

[83] Manitoba Hydro 2008/09 General Rate Application Filing, provided by Manitoba Hydro, http://www.hydro.mb.ca/regulatory_affairs/electric/information_requests.shtml.

- Strategic risks

7.4 SaskPower

SaskPower Corporation ("SaskPower") is the principal supplier of electricity in the Canadian province of Saskatchewan, serving more than 445,000 customers. SaskPower was incorporated as a provincial Crown Corporation under the mandate of the Saskatchewan Power Corporation Act. The vertically integrated public utility generates electricity in thermal, hydroelectric and wind powered facilities, and delivers its output via its transmission and distribution system all across Saskatchewan. The corporation has interconnections with Manitoba, Alberta and North Dakota.

Figure 28. SaskPower operational statistics 2006

			Share (%)
Generation capacity (MW)			
Coal	1,661		51.7
Gas	538		16.7
Hydro	854		26.6
Wind	161		5.0
Total	3,214		
Purchased power (MW)	454		
Electric sales (GWh)	17,400		
Exports	480		
Peak demand (MW)	2,960		
Generation (GWh)	17,246		
Transmission grid	12,212	km	
Distribution grid	142,843	km	
Total customers	445,000		

Source: SaskPower Annual Report 2006[84]

SaskPower operates 16 power generating facilities with an installed capacity of 3,214 MW. In addition, SaskPower has long-term purchase agreements worth 454 MW. Fossil fuel generating facilities contribute the majority of SaskPower's generation mix, with the remainder coming from hydro and wind. As of 2006, the net book value of SaskPower's generation facilities was CAD 1,846 million.[85]

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84 Annual Report 2006, SaskPower, p. 61, http://www.saskpower.com/aboutus/corpinfo/anreports/2006/.

85 Annual Report 2006, SaskPower, p. 48, http://www.saskpower.com/aboutus/corpinfo/anreports/2006/.

SaskPower's transmission and distribution grid serves a large geographic area and widely dispersed population. The transmission grid has a total length of 12,212 km, the distribution grid has a total length of 142,843 km. As of 2006, the net book value of SaskPower's transmission system was CAD 394 million.[86] The company's distribution system had a net book value of CAD 1,101 million.

7.4.1 Return on equity, capital structure and credit ratings

The Saskatchewan government approved SaskPower's rate application in January 2007.[87] The approval follows the Saskatchewan Rate Review Panel's (SRRP) review of SaskPower's rate application which includes an ROE of 8.5% and a deemed debt to capital ratio of 60%.[88]

Figure 29. SaskPower financial results 2006 (million CAD where applicable)

Total assets	4,163
Deemed debt to capital ratio	60%
Allowed ROE	8.50%
Credit ratings	
Canadian Bond Rating Service	A+
	A-1

Source: SaskPower Annual Report 2006[89]

7.4.2 Regulatory framework

SaskPower is subject to the provisions of the Crown Corporations Act of 1993, which gives the Crown Investments Corporation (CIC) of Saskatchewan, the holding company for Saskatchewan's Crown corporations, authority to set directions for SaskPower. SaskPower's rate proposals are reviewed by the SRRP, an advisory body to the government of Saskatchewan. The SRRP considers interest of customers, the Crown and the public, and then provides an opinion to the Minister of Crown Corporations on the fairness and reasonableness of the proposed changes. The government of Saskatchewan then makes the final decision.

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86 Ibid.

87 Press Release of the government of Saskatchewan, January 17, 2007, http://www.cicorp.sk.ca/cgi-bin/newsarchive/2007/01.

88 Saskatchewan Rate Review Panel, Report to the Minister of the Crown Investments Corporation of Saskatchewan, submitted January 11, 2007.

89 Annual Report 2006, SaskPower, p. 60, http://www.saskpower.com/aboutus/corpinfo/anreports/2006/.

7.4.3 Risk profile

The Board of SaskPower identified the following risk groups as the major factors that could impact SaskPower's future operational and financial results:[90]

- Operational risks – risk group that includes equipment failures, outages, labour disputes, weather conditions, water levels, accidental loss of assets and business interruptions

- Commodity price risk – risk group that includes fluctuations in the quantities and prices of commodities, and exposure to variability of electricity market prices

- Foreign exchange risk – risk group that reflects exposure to various currencies due to electricity trading and acquisition of goods and services from foreign suppliers

- Interest rate risk – as of December 31, 2006, 100% of SaskPower's debt was at fixed rates; however, interest rates may change and influence SaskPower's performance

- Credit risk – includes risks of failure of counterparties' present and future obligations

- Changing environmental regulations – includes uncertainties regarding emerging environmental regulations

7.5 Newfoundland Power

Newfoundland Power Inc. ("Newfoundland Power") is a vertically integrated utility, supplying energy to approximately 85% of all consumers in the Canadian Province of Newfoundland and Labrador.[91] Newfoundland Power owns thermal and hydroelectric power generation facilities, and operates an extensive transmission and distribution grid throughout Newfoundland and Labrador. Newfoundland Power is an investor-owned utility, wholly-owned by Fortis, Inc. ("Fortis"), a diversified investor-owned electric holding company in Canada.

Newfoundland Power operates 23 hydroelectric generating plants, three diesel plants, and three gas turbine facilities. Total installed capacity is 139 MW. In addition, Newfoundland Power purchases electricity from Newfoundland and Labrador Hydro. In 2007, the cost of power purchases amounted to approximately CAD 327 million which equals about 90% of total electricity provided by Newfoundland Power.[92] As of 2006, the net book value of Newfoundland Power's generation assets was CAD 113,909 million.[93] The net book value of

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90 Annual Report 2006, SaskPower, p. 36, http://www.saskpower.com/aboutus/corpinfo/anreports/2006/.

91 Annual Report 2007, Newfoundland Power, Corporate Profile, published by Newfoundland Power on January 1, 2007, http://www.newfoundlandpower.com/AboutUs/Financial/Annual.aspx.

92 Quick facts Newfoundland Power 2007, Newfoundland Power website, http://www.newfoundlandpower.com/AboutUs/QuickFacts.aspx.

93 Annual Report 2007, Newfoundland Power, p. 41, published by Newfoundland Power, http://www.newfoundlandpower.com/AboutUs/Financial/Annual.aspx.

Newfoundland Power's distribution assets was CAD 425,260 million. The company's transmission and substations had a net book value of CAD 133,819 million.

Figure 30. Newfoundland Power operational statistics 2006

Generation capacity (MW)			Share (%)
Hydro	96		68.8
Diesel	7		5.0
Gas	37		26.2
Total	139		
Peak demand (MW)	1,142		
Transmission and distribution grid	11,000	km	
Total customers	232,262		

Source: Newfoundland Power Annual Report 2007[94]

7.5.1 Return on equity, capital structure and credit ratings

All of Newfoundland Power's common shares are owned by Fortis. Fortis owns a range of regulated utilities including one natural gas utility in British Columbia and electric utilities in five Canadian provinces and three Caribbean countries. The allowed ROE for 2007 was 8.95%%.[95]

Figure 31. Newfoundland Power financial results 2007 (thousand CAD where applicable)

Total assets	985,930
Deemed debt to capital ratio	55%
Allowed ROE	8.95%
Credit rating	
Moody's	Baa1 (stable)
DBRS	A (stable)

Source: Annual Report 2007, Newfoundland Power[96]

94 Annual Report 2007, p. 1, Newfoundland Power, published by Newfoundland, http://www.newfoundlandpower.com/AboutUs/Financial/Annual.aspx.

95 Decision and Order by the Newfoundland and Labrador Board of Commissioners of Public Utilities, in the matter of 2008 general rate application by Newfoundland Power, P.U. 32 (2007).

96 Annual Report 2007, Newfoundland Power, p. 17, 22, 31, 32, published by Newfoundland Power, http://www.newfoundlandpower.com/AboutUs/Financial/Annual.aspx.

7.5.2 Regulatory framework

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("Newfoundland PUB"). Newfoundland Power operates under cost-of-service regulation. The PUB approves customer rates that permit recovering estimated costs of providing service, including a reasonable rate of return. At Newfoundland Power, customer rates are adjusted annually through the operation of the Automatic Adjustment Formula which adjusts the cost of equity to be recovered based on changes in Government of Canada 30-year bond yields. Newfoundland PUB also sets the rates charged by Newfoundland and Labrador Hydro to Newfoundland Power.

7.5.3 Risk profile

Newfoundland Power is subject to following uncertainties which may affect future operational and financial results.[97]

- Economic conditions – electricity sales are influenced by economic factors, such as changes in employment levels, personal disposable income, energy prices and housing starts
- Energy supply – Newfoundland Power purchases 90% of its electricity from Newfoundland and Labrador Hydro; changes of rates or rate settings by the Newfoundland PUB may affect Newfoundland Power's earnings significantly
- Electricity prices – recent increases in customer electricity rates are expected to negatively influence electricity sales
- Regulation – risks that reflect uncertainties associated with cost-of-service regulation
- Regulatory assets and liabilities – the way in which these assets and liabilities are recovered is set by the Newfoundland PUB; changes in presently utilized methods may impact Newfoundland Power's future cash flow
- Environmental Regulation – failure to comply with federal and provincial environmental regulations could lead to penalties or claims by third parties
- Interest rates – the majority of Newfoundland Power's assets are financed with long-term debt, and not all interest rates are fixed

7.6 New Brunswick Power

The New Brunswick Power Group ("NB Power") is the largest power supplier in the Canadian province of New Brunswick. The Group consists of a holding company, providing strategic direction and governance to the subsidiaries, and four operating companies.

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[97] Annual Report 2007, p. 22, Newfoundland Power, published by Newfoundland Power, http://www.newfoundlandpower.com/AboutUs/Financial/Annual.aspx.

NB Power Generation Corporation ("NB Power Generation") is responsible for the operation of the oil, hydro, coal and diesel-powered generating facilities. NB Power Nuclear Corporation ("NB Power Nuclear") operates the NB Power's sole nuclear generating station Point Lepreau. NB Power Transmission Corporation ("NB Power Transmission") operates and maintains the transmission system while NB Power Distribution and Customer Service Corporation ("NB Power Distribution") is responsible for operating the distribution system. NB Power also owns NB Electric Finance Corporation ("NB Electric Finance"), a financial corporation created in conjunction with the enactment of the New Brunswick Electricity Act in 2004. NB Electric Finance acts as a financier to NB Power, raising debt from the province of New Brunswick.

NB Power Generation operates six hydroelectric, five thermal, and three combustion turbine power stations, with a combined installed capacity of 3,313 MW. NP Power Generation's fixed assets have a net book value of CAD 1,885 million.[98] NB Power Nuclear operates a CANDU 6 nuclear reactor with an installed capacity of 635 MW. NP Power Nuclear's fixed assets have a net book value of CAD 615 million. NP Power Transmission's fixed assets have a net book value of CAD 368 million. NP Power Distribution's fixed assets have a net book value of CAD 531 million.

98 Report 2006/07, NB Power, p. 16, 17, published by NB Power on September 30, 2007, http://www.nbpower.com/en/corporate/about/reports/reports.aspx.

Figure 32. NB Power operational statistics 2006/07

Generation capacity (MW)			**Share (%)**
Thermal	1,903		48.2
Hydro	884		22.4
Nuclear	635		16.1
Combustion turbine	526		13.3
Total	3,948		
Purchases (MW)	2,529		
Peak demand (MW)	3,160		
Generation (million kWh)			**Share (%)**
Hydro	2,891		22.6
Coal/Petroleum coke	2,756		21.5
Oil	2,632		20.6
Nuclear	4,142		32.3
Other	383		3.0
Total	12,804		
Transmission grid	6,703	km	
Distribution grid	20,030	km	
Total customers	373,207		

Source: NB Power Annual Report 2006/2007[99]

7.6.1 Return on equity, capital structure and credit ratings

NB Power is 100% owned by the government of New Brunswick. In March 2003, the New Brunswick Energy and Utilities Board ("NB PUB") set NB Power Transmission's ROE at 9.5%, based on a deemed capital structure of 65% debt.[100] In its most recent rate decision filing of February 2008, the NB PUB has accepted NB Power Distribution approach of using an interest coverage ratio instead of applying an allowed ROE.[101]

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99 Report 2006/07, NB Power, p. 3, 52, published by NB Power on September 30, 2007, http://www.nbpower.com/en/corporate/about/reports/reports.aspx.

100 NB PUB, Decision March 13, 2003, p. 10, 28, http://www.pub.nb.ca/DecisionsEng.htm#Electricity.

101 NB Public Utilities Board adopted a regulation regime which determines NB Power Distribution's net income through an interest coverage ratio rather than through a regulated return on equity. Although the Board did mention it believed an allowed ROE to be the best method for regulating net income, it cited the fact that such a method wasn't possible as no equity injection had been made by NB Power shareholders

Figure 33. NB Power financial results 2006/07 (million CAD)

Total Assets	3,969
Deemed debt to capital ratio	65%
Allowed ROE	9.50%
Credit ratings NB Electric Finance	
Standard&Poor's	AA-
Moody's	Aa1
DBRS	A (high)

Source: NB Power Annual Report 2006/2007 and NB Power Credit Ratings[102]

7.6.2 Regulatory framework

NB Power was established as a Crown Corporation of the Province of New Brunswick by enactment of the New Brunswick Electric Power Act. In 2004, the New Brunswick Energy and Utilities Board ("NB PUB") was put in place under the New Brunswick Electricity Act to ensure power rates that are just and reasonable.[103] In determining rates for NB Power Distribution, the NB PUB considers the company's revenue requirement for the following year. The revenue requirement is the amount of revenue that NB Power Distribution must have to cover its costs, including an appropriate level of net earnings and taxes. The Electric Power Act does not provide the NB PUB with regulatory authority over NB Power's generation operations.

7.6.3 Risk profile

NB Power identified a range of factors that have significant impact on financial performance due to cost of generation and price competitiveness.[104]

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and that NB Power had only accumulated nominal retained earnings to this point. The Board therefore approved an interest coverage ratio of 1.10. see NB PUB, Decision February 22, 2008, p. 24, http://www.pub.nb.ca/DecisionsEng.htm#Electricity.

102 Annual Report 2006/2007, NB Power, p. 50, 54, published by NB Power on September 30, 2007, http://www.nbpower.com/en/corporate/about/reports/reports.aspx; Credit ratings NB Electric Finance 2007, provided by NB Power, http://www.nbpower.com/en/customers/regulatory/regulatory.aspx.

103 New Brunswick Electricity Act 2004, provided by Government of New Brunswick, http://www.gnb.ca/index-e.asp.

104 Annual Report 2006/2007, NB Power, p. 22, published by NB Power on September 30, 2007, http://www.nbpower.com/en/corporate/about/reports/reports.aspx.

- Hydro generation – when flows are below anticipated levels, other more expensive fuels are used to compensate for the shortfall

- Nuclear generation – NB Power's nuclear generating station supplies approximately 30% of New Brunswick's energy requirements

- Oil, coal, and natural gas prices – NB Power is exposed to changing commodity prices

- Exchange rates – NB Power is exposed to foreign exchange risk through fuel and purchased power priced in USD

7.7 Hydro One

Hydro One, Inc. ("Hydro One") is wholly-owned by the Canadian Province of Ontario and the province's largest electricity delivery company. Hydro One Networks, Inc. ("Hydro One Networks"), one of four wholly-owned subsidiaries of Hydro One, owns and operates approximately 97% of Ontario's high-voltage transmission system.[105] Hydro One Networks, together with Hydro One Brampton, also owns and operates about one third of the province's distribution system. Hydro One's subsidiary Hydro One Remote Communities generates and delivers electricity across northern Ontario; Hydro One telecom operates a province-wide telecom system.

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105 About Hydro One Networks, Hydro One website, http://www.hydroonenetworks.com/en/about/default.asp.

Figure 34. Hydro One Networks operational statistics 2008

Transmission lines	28,600
Distribution lines	122,800
Transmission and switching stations	274
Distribution and regulation stations	1,035
Towers	48,000
Transformers	520,000
Electricity transmitted (TWh)	151
System peak (MW)	27,005
Customers	
Large industrial	113
Remote communities served	18
Retail	1.3 million
Municipal utilities	92
Generators	171

Source: Hydro One Networks website[106]

7.7.1 Return on equity, capital structure and credit ratings

For the years of 2007 and 2008, the ROE of Hydro One's transmission operations was set at 8.35%.[107] The ROE for Hydro One's distribution arm for 2006 and 2007 was set at 9%.[108]

106 Ibid.

107 OEB Decision EB-2006-0501, p. 73, filed August 16, 2007, provided by OEB, http://www.oeb.gov.on.ca/OEB/Hearings%20and%20Decisions/Decisions%20and%20Reports/2007%20Decisions%20and%20Reports.

108 OEB Decision EB-2005-0378, p. 2, filed April 12, 2006, provided by Hydro One Networks, http://www.hydroonenetworks.com/en/regulatory/2006_distribution_rate_application/default.asp.

Figure 35. Hydro One financial results 2007

Total assets	12,791	
Deemed debt to capital ratio	60%	
Allowed ROE	8.35%	
Credit ratings	Short-term debt	Long-term debt
DBRS	R-1 (middle)	A (high)
Moody's	Prime-1	Aa3
Standard&Poor's	A-1	A

Source: Hydro One Annual Consolidated Financial Statement 2007 and Hydro One Rating Agency Report 2008[109]

7.7.2 Regulatory framework

Hydro One's transmission and distribution operations are regulated by the OEB. The OEB set uniform province-wide transmission and distribution rates which are set based on an approved revenue requirement that ensures cost recovery and a return on deemed common equity. Additionally, the OEB approves rate riders that allow the recovery of specific regulatory assets and liabilities.

Hydro One's low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP). Wholesale customers pay the market price adjusted for the difference between market prices and prices paid to generators regulated under the Electricity Restructuring Act of 2004. The Independent Electricity System Operator (IESO) is responsible for overseeing and operating the wholesale market.

7.7.3 Risk profile

Hydro One's risk management is lead by the company's Chief Risk Officer who monitors and reviews Hydro One's risk profile. As part of Hydro One's annual consolidated financial statement, following risk have been identified:[110]

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109 Annual consolidated financial statement 2007, Hydro One, pg. 55, published by Hydro One, http://www.hydroone.com/en/investor_centre/annual_reports/; Rating Agency Report, Hydro One, updated February 2008, Exhibit A of Hydro One Network's 2008 Distribution Rate Application, http://www.hydroonenetworks.com/en/regulatory/2008_distribution_rate_application/Dx_Rate_Filing/default.asp#A.

110 Annual consolidated financial statement 2007, Hydro One, pg. 16, published by Hydro One, http://www.hydroone.com/en/investor_centre/annual_reports/.

- Risk associated with transmission projects – risks related to uncertainties of transmission investments due to provincial approvals, claims of First Nations, public oppositions, and other potential obstacles

- Work force demographic risk – includes risks associated with Hydro One's aging work force

- Regulatory risk – reflects risks associated with OEB's regulatory authority to set transmission and distribution rates; risk group also includes potential load and consumption variations as well as unexpected investment needs

- Asset condition – risks associated with potential delays of necessary construction and maintenance of Hydro One's wires due external factors such as outage constraints as set by the IESO and increasing lead times for material and equipment

- Risk of natural and other unexpected occurrences – reflects risks related to weather conditions, natural disasters and catastrophic events

- Risk from transfer of assets located on Indian lands – reflects potential costs related to the required eventual purchase of some assets located on lands held for bands and bodies of Indians under the Indian Act

- Labour relations risk – financial risks related to Hydro One's ability to negotiate collective bargaining with the Power Workers Union

- Environmental risk – risk group reflecting failure to comply with existing environmental regulations (includes potential penalties and other claims of third parties); risks associated with future environmental regulations

- Risk associated with Information Technology infrastructure – reflects risks related to Hydro One's conversion of current financial and business processes to an integrated business and financial reporting system

- Risk associated with outsourcing arrangements – includes risks associated with the potential termination of the existing outsourcing agreement with Inergi

- Risk from provincial ownership of transmission corridors – includes risks due to Hydro One's limited ability to use provincially-owned transmission corridors

- Pension plan risk – reflects risk associated with failure of pension costs and failure to attain of OEB's approval of pension cost recovery

- Risk associated with arranging debt financing – includes uncertainties of Hydro One's ability to arrange sufficient and cost effective debt financing due to market conditions, results of operations, regulatory environment, etc.

- Market and credit risk – includes risks related to fluctuations in interest rates

8 Appendix B: Detailed snapshots of selected US federal and state power authorities

8.1 Tennessee Valley Authority

The Tennessee Valley Authority ("TVA") is a wholly-owned corporate agency of the United States ("US") and the nation's largest public power company. TVA operates fossil, nuclear, and hydroelectric power plants as well as a mix of alternative generation facilities based on solar power, wind power and methane gas. TVA provides its output to municipal and cooperative power distributors, large industrial customers and federal institutions in all of Tennessee and parts of Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Virginia. TVA owns and operates one of the largest transmission systems in the US and provides transmission services to other qualified power suppliers.

The company's power generating sites include 29 conventional hydroelectric facilities, one pumped-storage hydroelectric facility, 11 coal-fired power stations, three nuclear plants, eight combustion turbine facilities, two diesel generators, one wind farm, one digester gas site, and 16 solar power stations. TVA owns and operates approximately 15,800 circuit miles of transmission lines.

Figure 36. TVA operational statistics 2006/07

Generation capacity (MW)		**Share (%)**
Coal	15,052	45.1
Nuclear	6,898	20.6
Hydro	5,186	15.5
Combustion turbine	6,258	18.7
Other	16	0.05
Total	33,410	
Peak demand (MW)	33,482	
Generation (GWh)	156,389	
Purchased Power (GWh)	22,141	
Transmission circuit length (mi)	15,800	
Customers (municipalities and cooperatives)	158	

Sources: TVA Annual Report and TVA's Annual Report to the SEC[111]

[111] TVA Annual Report 2006/07, published by TVA, p. 22, http://www.tva.gov/finance/reports/index.htm; Annual Report TVA, Form 10-K, filed by TVA to the Securities and Exchange Commission ("SEC") on December 12, 2007, p. 19, http://www.tva.gov/finance/reports/forwardlooking_sec.htm.

8.1.1 Capital structure and credit ratings

TVA is a financially self-supporting company. TVA does not receive funding from taxpayers or congressional appropriations. Instead, TVA finances all of its operations and programs, including those for environmental protection and economic development, through sales of power and issuance of bonds in the financial markets. TVA is not authorized to issue equity securities such as common or preferred stocks, and has, therefore, no equity-based compensation. TVA's bonds and notes are backed by the TVA power system.

Based on information provided in TVA's filing to the Security and Exchange Commission (SEC) for the period ended September 30, 2007, TVA's debt ratio stands at 91%.

Figure 37. TVA financial results 2006/07 (million USD)

Net income	383
Total Revenues	9,244
Total Assets	33,902
Debt to capital ratio	91%
Credit ratings	
Standard&Poor's	AAA
Moody's	Aaa
Fitch	AAA

Source: TVA Annual Report and TVA's Annual Report to the SEC[112]

8.1.2 Regulatory framework

TVA is a self-regulated entity whose objectives and responsibilities are stipulated in the TVA Act, enacted by the US Senate and House of Representatives.[113] According to the TVA Act, the TVA Board has the responsibility for setting the power rates at the lowest possible level. These rates are not subject to judicial review or review by any regulatory body. Since the TVA is not a "public utility" as defined in the Federal Power Act ("FPA"), the TVA not subject to the full jurisdiction that Federal Regulatory Energy Commission ("FERC") exercises over public utilities.

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112 Annual Report TVA, Form 10-K, filed by TVA to the SEC on December 12, 2007, p. 93, http://www.tva.gov/finance/reports/forwardlooking_sec.htm.

113 TVA Act of 1933 as amended, provided by TVA, Section 11, 13, 14, http://www.tva.gov/finance/governance/index.htm.

TVA is required to charge power rates which will generate gross revenues sufficient to cover costs associated with the operation and maintenance of its power system, service on outstanding debts, payments in lieu of taxes, and payments to the US Treasury as a repayment of the appropriation investment that the US provided for TVA's power generating facilities ("Power Facilities Appropriation Investment").

8.1.3 Risk profile

TVA's revenue requirements are subject to a range of risk factors which could cause future results to differ substantially from historical results. TVA differentiates between four risk categories: strategic risks, operational risks, financial risks, and risks related to TVA securities.[114]

Strategic risks

Change of laws, regulations and administrative orders may negatively affect TVA's cash flow, operations and financial conditions; some of the possible risks include:

- Loss of protected service territory
- Loss of sole authority to set power rates
- Increased environmental regulations
- Significant restrictions on TVA imposed by the US Nuclear Regulatory Commission
- Loss of responsibility for managing the Tennessee River System
- Downgrade of TVA's credit rating
- More restrictive debt ceiling

Operational risks

- Generation and transmission assets do not operate as planned
- Disrupted fuel supply
- Compliance with environmental laws and regulations may affect TVA's operations in unexpected ways
- Increase of demand – TVA is sole power provider within its service territory; if demand increases, TVA is obliged to meet increased demand
- Volatile purchase power prices; failure of providers of purchase power to comply with contracts with TVA

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114 Annual Report TVA, Form 10-K, filed by TVA to the Securities and Exchange Commission ("SEC") on December 12, 2007, p. 50, 56, 93, http://www.tva.gov/finance/reports/forwardlooking_sec.htm.

- Weather conditions
- Delays and additional costs in power plant construction
- Problems to attract and retain skilled workers
- Involvement in various legal and administrative proceedings
- Disrupted reliability of TVA's transmission system due to problems at other TVA facilities
- Problems at non-TVA facilities affecting water supply to TVA's generation facilities
- Incidents at TVA's nuclear generation facilities
- Changes in technology regarding alternative power generation

Financial risks

- TVA is subject to a variety of market risks, including commodity price risks, investment price risks, interest rate risks, and credit risks
- Significant unplanned contributions to fund its pension and other post-retirement benefit plans
- Significant unplanned contributions to its nuclear decommissioning trust
- Approaching or reaching TVA's debt ceiling
- Economic downturns
- Failure of TVA's financial control system
- Loss of ability to use regulatory accounting

Risks related to TVA Securities

- Payment of principal and interest on TVA securities not guaranteed by the U.S.
- Trading market for TVA securities may be limited

8.2 Bonneville Power Administration

The Bonneville Power Administration ("BPA"), headquartered in Portland, Oregon, is a federal agency under the US Department of Energy. BPA markets wholesale electricity from 31 federal hydro projects, one non-federal nuclear power plant, and several other small non-federal power plants to the region's public utilities, municipalities, investor-owned utilities, power marketers and some large industrial customers in Canada and western U.S. BPA provides approximately 35% of the electricity used throughout the Pacific Northwest.[115] BPA also operates and maintains about 75% of the high-voltage transmission system in its service territory which includes Idaho, Oregon, Washington, western Montana, and parts of eastern Montana, California, Nevada, Utah and Wyoming. The total length of BPA's transmission grid is approximately 15,000 miles.

8.2.1 Capital structure and credit ratings

BPA, a self-financed public service organization, with rates set primarily to assure that costs are met. BPA recovers its cost through sales of electricity and the provision of transmission and other services. BPA raises additional funds through the issuance of bonds in financial markets. As of September 2007, BPA's debt ratio was 88%.

8.2.2 Regulatory framework

The Pacific Northwest Electric Power Planning and Conservation Act ("Northwest Power Act")[116] guides BPA ratesetting. The Northwest Power Act aims to provide rates for the sale and disposition of power which recover, in accordance with sound business principles, all costs necessary to produce, transmit, and conserve electric energy.[117]

BPA's power rates recover costs associated with BPA's electricity operations, including generation operating expenses related to Northwest federal dams and certain non-federal nuclear projects, BPA's power purchases, fish and wildlife protection, energy conservation, renewable resource development, and the Residential Exchange Program.[118] In addition, BPA is required to make annual payments to the U.S. Treasury ("Power Facilities Appropriation Investment"), which are made after all other BPA costs are covered. At the completion of BPA's rate hearing, BPA files its rates with the FERC for approval.

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115 About BPA, BPA website, http://www.bpa.gov/corporate/About_BPA/who.cfm.

116 Chapter 12H of the U.S. Code of December 5, 1980.

117 Pacific Northwest Electric Power Planning and Conservation Act, United States Code, Section 839e(1), provided by Northwest Power and Conservation Council, http://www.nwcouncil.org/LIBRARY/poweract/default.htm.

118 Revenue Requirement Study BPA, Wholesale Power Rate Case Initial Proposal, November 2006, https://secure.bpa.gov/ratecase.

Figure 38. BPA financial results 2006/07 (million USD)

Net income	457
Total Revenues	3,268
Total Assets	19,963
Debt to capital ratio	88%
Credit ratings	
Standard&Poor's	AA-
Moody's	Aaa
Fitch	AA-

Source: BPA Annual Report and BPA Credit Rating Report[119]

8.2.3 Risk profile

In order to provide a high probability of fulfilling its financial obligations, BPA performs a risk analysis as part of its rate-making process. In this risk analysis BPA identifies key risks and analyzes their impacts on net revenues. BPA divides its risk profile in operational and non-operational risks. [120]

Operational risks

- Pacific Northwest and federal hydro generation risks – risk factors reflecting impacts in timing and volume of hydro stream flows on monthly Pacific Northwest and federal hydro production

- Pacific Northwest and BPA load risks – risk factors reflecting impacts of economic conditions and fluctuations in temperature on spot market prices

- California hydro generation risks – risk factors reflecting impacts of changes in timing and volume of stream flows on monthly production in California

- California load risks –risk factors reflecting impacts of economic conditions and fluctuations in temperature on California loads and spot market prices

119 Annual Report 2007, BPA, published by BPA, p. 46, 47, http://www.bpa.gov/corporate/finance/a%5Freport/; Credit Rating Report, March 2007, Fitch Ratings, Standard&Poor's, and Moody's Investors Service, published by BPA, http://www.bpa.gov/corporate/Finance/Debt_Management/reports_articles/.

120 BPA Risk Analysis Study, published by BPA as part of BPA's 2007 Wholesale Case, November 2005, p. 12-25, https://secure.bpa.gov/ratecase/Documents.aspx?ID=12.

- Natural gas price risks – risk factors reflecting uncertainties of producing electricity from gas-fired power plants throughout the WECC region

- Nuclear plant generation risks – risk factors reflecting uncertainties in the amount of electricity generated by the Columbia Generating Station

- Investor-Owned Utility Residential Exchange Program ("IOU REP") settlement benefits risks – risk factors reflecting uncertainties in the amount of benefits from the IOU REP settlement, relative to benefits included in previous rate settings

- Direct Service Industry ("DSI") benefits risks – risk factors reflecting uncertainties in the amount of DSI payments

- Wind resource risks – risk factors reflecting uncertainties in the amount of electricity generated by BPA's wind farms

- Transmission expense risks – risk factors reflecting uncertainties in transmission and ancillary expenses

- Credit risks – risk factors reflecting uncertainties in the amount of credits BPA is allowed to credit against its annual U.S. Treasury payments

Non-operational risks

BPA includes operational risks through its Non-Operating Risk Model ("NORM"). NORM models the impact on expected costs associated with risks surrounding projections of revenue and expense levels related to BPA's generation function.

8.3 New York Power Authority

Figure 39. NYPA operational statistics 2006

Generation capacity (MW)	
Hydro	4,240
Small hydro	27
Thermal	1,521
Total	5,788
Transmission circuit length (mi)	1,400

Source: NYPA website[121]

The Power Authority of New York State ("NYPA") is a corporate municipal and political subdivision of the State New York, created in 1931 and authorized by the Power Authority Act

121 Corporate website NYPA, NYPA facilities, http://www.nypa.gov/facilities/default.htm.

of the State of New York to provide continuous and adequate supply of electric power. The public utility operates a number of hydroelectric and fossil-fueled power generating facilities, and delivers electricity through its transmission system to customers all across New York State. NYPA sells its output to government agencies, community-owned electric systems, electric cooperatives, private utilities, and neighboring states.

8.3.1 Capital structure and credit ratings

NYPA is a non-profit public energy corporation. NYPA does not use tax revenues or state credits. Instead NYPA finances its operations through bond sales to private investors. As at December 31, 2006, NYPA's debt to capital ratio was 68%.

Figure 40. NYPA financial statistics 2007

Net income	235
Total Revenues	3,072
Total Assets	7,008
Debt to capital ratio	68%
Credit ratings	**Long-term debt**
Standard&Poor's	AA-
Moody's	Aa2
Fitch	AA

Source: NYPA Annual Report 2007[122]

8.3.2 Regulatory framework

The New York Power Authority sells electric power to government agencies, community-owned electric systems and rural electric cooperatives, companies, private utilities for resale (without profit) to their customers, and to neighboring states,. It is a state government quasi-self regulating entity whose rates do not fall under the regulation of any state or federal agency with the exception of transmission rates which are governed by NYISO's Open-Access Transmission Tariff (OATT), which is in turn approved by FERC.

NYPA's rates, which are intended to be set at levels sufficient to repay debt and cover operating costs, serve as an economic promotion tool for the state of New York. Rates are determined through budget review conducted by NYPA's Board of Trustees. The board of trustees consists of seven trustees who are appointed by the Governor of New York, by and with the advice and

122 Annual Report 2007, NYPA, p. 28, 29, http://www.nypa.gov/financial/default.htm.

consent of the Senate. Note that NYPA's customer rates vary depending on the contract terms entered into with NYPA.

8.3.3 Risk profile

NYPA's risk management has identified following major risk factors:[123]

- Interest rate risks – includes risks associated with NYPA's forward interest swaps and fixed-to-floating interest rate swaps
- Energy market risks – includes risk associated with NYPA's long-term forward energy swap agreements to fix costs of energy in order to meet long-term customer load requirements; also includes NYPA's energy fixed-to-floating energy swaps and short-term energy swaps
- Fuel market risks – includes risks associated with NYPA's purchase of natural gas swaps and NYMEX contracts in order to limit its exposure to floating market prices

123 Annual Report 2006, NYPA, p. 22, http://www.nypa.gov/financial/default.htm.

9 Appendix C: abridged corporate CV

9.1 Ontario-specific engagements

- ***revenues to hydro portfolio in Ontario:*** For a large North American industrial company, A.J. led the creation of a market study and report underlying the issuance of income trust securities. Tasks included multiple scenario analysis of merchant revenues, review of ancillary services revenues, and an examination of the Ontario hybrid market structure

- ***assessment of role of peaking plant in Ontario power sector:*** for Ontario government body, performed extensive scenario analysis to determine extent to which peaking plant should be a part of future procurement plans in the province; this analysis included assessment of revenues from ancillary services and of optionality

- ***due diligence associated with Ontario transmission and distribution assets:*** applied detailed understanding of performance-based ratemaking concepts to advise on valuation and strategic considerations associated with a bid for the largest transmission and distribution company in Ontario

- ***valuation of Ontario generating plants, including assessment of regional electricity markets:*** organized and implemented major modeling effort to determine potential value of generation stations in Ontario. Assessed impact of transmission constraints and restructuring efforts in neighboring markets on future wholesale market prices

- ***impact of Ontario market changes on industrial consumers:*** for association of large power consumers in Ontario, assessed market trends and future entry and exit scenarios to determine long term price dynamics in the face of changes in government deregulation policies

- ***incentive-based contract design:*** for Ontario Power Authority, advised on provisions of power purchase agreement associated with incentives for optimization of production in peak periods for hydro facility owned by a major generator

- ***upstream capability to deliver conservation and demand management:*** for Ontario Power Authority, performed examination of capabilities of Ontario to provide necessary inputs to assure that Ontario meets is conservation and demand management targets; report incorporated into Integrated Power System Plan submission to OEB

- ***regulation of generation in Ontario:*** for Ontario Energy Board, A.J. authored paper described the ways in which legacy assets of Ontario Power Generation could be regulated, including incentive regulation and a set of regulatory contracts. Deliverables included providing technical advisory during public workshop

- ***potential for regulation of retail market auctions:*** for Ontario Energy Board, A.J. led engagement to review practice of regulatory oversight of load auctions to serve default supply across North America

- ***examination of contracting processes in Ontario:*** on behalf of the Ontario Power Authority, met with over 50 stakeholder groups to determine potential ways in which contracting process for new supply could be improved. Engagement included assessing practices in other jurisdictions and review of standard offer processes

- ***market power concerns in Ontario:*** determined concentration ratios for existing configuration of generation plant, developed set of recommended portfolios to minimize market power across all timeslots in hourly market in preparation for divestiture or other market power mitigation mechanisms

- ***price forecasts in key Canadian markets:*** provided long term electricity price forecasts for key Canadian markets, including Alberta, British Columbia, and Ontario

9.2 Generation valuation

- ***valuation of Singapore generating asset:*** on behalf of a large Asian generating company, provided revenue forecasts from spot, retail, and vesting contracts for Singapore generator. Analysis included review of repowering options, assessment of regulatory evolution, and potential for strategic behavior

- ***prices for merchant generators and IPPs:*** provided expert opinion on the extent to which value of a generating station could change over a 12 to 18 month period, based on historical analysis of price changes for individual generation assets as well as for generation asset portfolios

- ***revenues to wind generators in Alberta:*** A.J. led the examination of merchant revenues to a portfolio of existing and under construction wind generators in the province of Alberta. Tasks included review of market design issues, 20 year scenario analysis for merchant revenues, review of contract terms and conditions, and an examination of the potential for additional revenues from the sale of emissions reduction credits and renewable energy certificates. Deliverables included market study supporting issuance of income trust units

- ***valuation of generation and distribution assets in Philippines and the Caribbean:*** provided detailed analysis of regulatory trends in the Philippines and in selected Caribbean countries. Used regulatory filings, PPAs, and public information to develop a value for generation and distribution assets in these markets. Advised potential buyer on relative risk in each country examined, including country risk, regulatory risk, and fuel supply and load growth issues.

- ***valuation of New England based generation portfolio:*** worked with potential acquirer of New England's largest generation portfolio to determine the costs of ongoing obligations associated with the portfolio, provide an understanding of long term market dynamics, and assess value of overall portfolio, including revenue forecasts and review of market rules

- ***global generation investment strategy:*** for a major Canadian generation company, used modern portfolio theory to identify combination of asset classes and geographic locations which would result in optimal risk-reward combination for generator given its core competencies. Deliverables included interactive model to be used by generator staff on an ongoing basis

9.3 Expert testimony

- ***assessment and valuation of quantum meruit claims:*** for advisor and developer of biomass facilities, provided expert opinion on value of services provided based on industry knowledge, review of correspondence, and experience providing or commissioning similar services

- ***conservation and demand management (C&DM) in Ontario:*** wrote testimony related to the alternative ratemaking approaches available regarding C&DM; addressed innovative alternatives and compared and contrasted various schemes in the Ontario context

- ***valuation of PPAs associated with IPPs in Thailand:*** as an expert witness in an arbitration case, A.J. quantified the change in value resulting from modifications to several PPAs associated with a power project in Thailand. Engagement included review of PPAs, evaluation of Thai power sector restructuring process, extensive modeling of financial aspects of PPAs, and assessment of financing alternatives; client won on all claims

- ***review of Dutch electricity market regulatory dynamics:*** in a case related to economic substance, provided understanding of how Dutch electricity market was structured in the mid-1990s, how it was expected to evolve, and how it did actually evolve. Issues addressed included market structure, regulation, role of non-utility investors, and role of private and international investors.