EB-2010-0008

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule. B;

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain of its generating facilities (the "OPG 2011-2012 Payment Amounts Application").

ONTARIO POWER GENERATION INC.

CROSS-EXAMINATION REFERENCE BOOK

October 28, 2010

TORYS LLP
Suite 3000
79 Wellington Street W.
Box 270, TD Centre
Toronto, Ontario
M5K 1N2 Canada

Charles Keizer
416.865.7512

Crawford Smith
416.865.8209

Counsel for the Ontario Power Generation Inc.

TAB 1

Before the Ontario Energy Board

In the matter of:

EB-2010-0008
2011-2012 Payment Amounts for OPG's Prescribed Facilities

Exhibit M
Tab 10

Evidence Filed on Behalf of Pollution Probe

On Issue List Items 3.1, 3.3 and Related Issues

Text, Appendices and Schedules

Prepared Testimony of

Dr. Lawrence Kryzanowski and Dr. Gordon S. Roberts

Senior Concordia University Research Chair in Finance, John Molson School of Business, Concordia University, Montreal; and CIBC Professor of Financial Services, Schulich School of Business, York University, Toronto.

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1. INTRODUCTION AND SUMMARY

1.1 Qualifications

This evidence is the work of Dr. Lawrence Kryzanowski of Concordia University and Dr. Gordon S. Roberts of York University. Dr. Kryzanowski is currently a Full Professor of Finance and Senior Concordia University Research Chair in Finance (previously Ned Goodman Chair in Investment Finance) at Concordia University. He earned his Ph.D. in Finance at the University of British Columbia. Dr. Gordon S. Roberts is currently CIBC Professor of Financial Services at York University's Schulich School of Business. He earned his Ph.D. in Economics at Boston College.

Dr. Kryzanowski has experience in preparing evidence as an expert witness in utility rate of return applications, stock market insider trading court proceedings, and confidential final offer arbitration hearings for the setting of fair rates for the movement of various products by rail. Together with Dr. Roberts in 1997, he prepared a report for the Calgary law firm, MacLeod Dixon, on rate of return considerations in the pipeline application by Maritimes and Northeast. Drs. Kryzanowski and Roberts provided evidence also for a group of organizations collectively and most recently referred to as the Consumers Group (formerly UNCA Intervenor Group and FIRM Customers) on the fair return on equity and the recommended capital structure for ATCO Electric Limited in its 2001/2002 Distribution Tariff Application and for Aquila Networks Canada (Alberta) Ltd. ("ANCA") in its 2001/2002 Distribution Tariff Application and its 2002 Distribution Tariff Application (DTA) No. 1250392 before the Alberta Energy and Utilities Board. On behalf of the Province of Nova Scotia, they provided evidence and testified before the Nova Scotia Utility and Review Board in the matter of Nova Scotia Power Inc. in 2002. They filed evidence and testified before the Régie de l'Enérgie du Quebec for the Fédération canadienne de l'entreprise indépendante ("FCEI") / Union des municipalities du Québec ("UMQ") & Option consommateurs ("OC") in Hydro Quebec Distribution's 2003 application. Together with Dr. Roberts, and on behalf of Consumers Group, Dr. Kryzanowski prepared testimony and testified in Generic Hearing No. 1271597 before the Alberta Energy and Utilities Board in 2003-2004. Together with Dr. Roberts, he submitted evidence and testified before the Public Utilities Board of the Northwest Territories in the General Rate Application of Northwest

Territories Power Corporation in 2007; and on behalf of Pollution Probe in EB-2007-0905 – OPG – 2008-09 Payments before the Ontario Energy Board in 2008. More recently, Drs. Kryzanowski and Roberts submitted evidence and testified on behalf of the Office of Utilities Consumer Advocate (UCA) in the 2009 Generic proceedings before the Alberta Utilities Commission (AUC).

Dr. Roberts is also experienced in preparing evidence for utility rate of return hearings. From 1995-1997, he submitted prefiled testimony as a Board witness in rate hearings for what was then known as Consumers Gas. In 1996, he served as an expert advisor to the Ontario Energy Board in its Diversification Workshop. As noted above, together with Dr. Kryzanowski, he has also prepared evidence on rate of return and capital structure considerations and appeared before regulatory boards in Nova Scotia, Quebec, Ontario and Alberta.

More broadly, Drs. Kryzanowski and Roberts often provide technical expertise and advice on financial policy. Among our consulting clients in recent years are the Superintendent of Financial Institutions, the federal Department of Finance, Canada Investment and Savings, Canada Mortgage and Housing Corporation, and Canada Deposit Insurance Corporation. Our brief *curricula vitae* are attached as an Appendix.

1.2 Purpose of Evidence and General Approach

Pollution Probe has retained us to provide evidence on the following two items in the Revised Draft Issues List as well as related issues:[1]

3.1 What is the appropriate capital structure and rate of return on equity?

3.3 Should the same capital structure and cost of capital be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure and/or cost of capital parameters are appropriate for each business?

[1] Ontario Power Generation Inc., 2011-2012 Payment Amounts for Prescribed Generating Facilities, EB-2010-0008, *Revised Draft Issues List*, July 7, 2010.

In preparing our evidence, we considered and used various techniques for determining an appropriate capital structure (and fair rate of return) for a regulated utility and its regulated divisions. Although OPG has a single shareholder (i.e. the Province of Ontario), we follow the stand-alone principle under which capital structure (and the fair return on equity) are determined as if the company were "standing alone" as a shareholder-owned entity.

For determining an appropriate capital structure for OPG, we begin with a brief overview of financial theory focused on the practical implications for capital structure. Our main conclusions are that: 1) the level of equity should increase with the degree of business risk; and 2) capital structures are best set using a heuristic approach given the absence of a generally accepted formula for setting capital structure. We then review the business risks faced by OPG's hydro assets and nuclear assets separately and compare them with those of other utility industry sectors as well as with selected individual regulated companies. We next conduct an analysis of bond ratings, capital structures, interest coverage ratios, returns on equity and equity ratios (both actual and those allowed by regulators) for a comparable sample of utilities. Drawing on the basic principle that the level of equity in the deemed capital structure of a utility should reflect its business risk and combining our risk assessments and benchmarks, we conclude that business risk is unchanged since the Board's Decision in EB-2007-0905 for both divisions and the total regulated OPG. Consistent with the overall equity thickness for the combined regulated entity of 47% recommended in our 2008 Evidence and adopted by the Board, we recommend 40% and 50% as the appropriate equity ratios respectively for OPG's regulated hydro and nuclear assets given their relative business risks.

1.3 Summary of Evidence

1.3.1 Case for maintaining currently allowed equity thickness and return on equity for OPG's aggregate regulated operations

In Section 2, we assess the efficacy of OPG's use of the allowed ROE derived from the modified automatic ROE adjustment mechanism established in the OEB's Cost of Capital Report and the capital structure approved for OPG in EB-2007-0905. Based on the looking-forward survey data of knowledgeable professionals, we find that both the reset Base ROE of 9.75% and the utility-specific equity risk premium (ERP) of 5.5% are: 1) marginally below their corresponding median counterparts for the market as a whole of 10% and 5.7% for a short-term (2010) horizon; 2) substantially above their corresponding median counterparts of 8.0% and 3.0% for a mid-term horizon (2011-2014); and 3) substantially above their corresponding median counterparts of 8.0% and 2.7% for a long-term horizon (2015-2024). We also find the reset utility-specific ERP of 5.5% is considerably higher than that for the market, which has a considerably higher risk than an A-rated regulated utility. This is the case even for the period with the highest market equity risk premiums (MERPs) (namely, the 110-year period of 1900-2009) of 3.7% and 4.2% respectively for Canada and the U.S. Based on these risk assessments, the finding that the Base ROE and implied utility ERP exceed those of the higher-risk market equivalents leads us to the conclusion that the Board's formula continues to provide a generous return for regulated utilities.

1.3.2 Case for setting separate equity thicknesses for OPG's regulated nuclear and hydroelectric operations

In section three, we examine the case for setting separate equity thicknesses for OPG's nuclear and hydro operations. We argue that the main benefits of divisional capital structures (and the resulting costs of capital) are in terms of efficiently allocating the scarce resource of capital since using the same capital structures and costs of funds (i.e. same costs of capital) instead for divisions that differ in riskiness will cause the utility to accept "bad" high-risk projects and reject "good" low-risk projects.

A secondary effect of not reflecting divisional differences in risk is the feedback effect on the rate-setting process. As a utility using a firm-level discount or hurdle rate over time commits to investments that are biased towards "bad" high-risk projects for nuclear and away from "good" low-risk projects for hydro, the weighted-average riskiness of the utility increases as a result. Over time, this in turn leads to utility applications for higher allowed returns on equity and/or greater equity thickness.

The only seemingly material argument made by Ms. McShane (and adopted by OPG) is that none of the cost of capital methodologies that she examined yielded a robust and analytically sound basis for specifying technology-specific costs of capital. However, Ms. McShane's examination inappropriately concentrated on: 1) whether meaningful market model betas could be calculated using various methodologies; and 2) samples of U.S. utilities that do (and do not) differentiate by the proportion of their electricity generation that was nuclear or hydro. Ms. McShane also evaluated a number of methodologies that have been utilized for estimating the cost of equity that is used in the determination of the divisional costs of capital **when the capital structure is already known or can be obtained independently**, which is not applicable here. Her approach also implicitly assumes that a formulaic approach can be used for setting divisional capital structures when one is deemed inappropriate for setting capital structure at the aggregate utility level. Instead, Ms. McShane should have examined differences in divisional debt capacities (e.g. equity thicknesses). This section of our evidence also deals with a number of technical shortcomings of her analysis and her non-consideration of heuristic approaches that are used by practitioners to determine divisional capital structures.

1.3.3 Economic and financial market conditions

In Section 4, we examine current economic and financial market conditions in Canada, the U.S. and Ontario, and review forecasts of those economic variables that we use as inputs in the capital structure tests.

The recent global credit crisis caused increased volatility in equity markets and wider spreads in debt markets. The growth in the Canadian economy is and is expected to be robust with moderate inflation going forward. However, Ontario has been a laggard, and it is expected to continue to be so during the test years due to the strong manufacturing emphasis in the province. In addition, most of the gap between current A-rated Canadian utility credit spreads and where they were prior to the credit crisis has closed. This has occurred while both components to this credit spread have declined over time. Another indicator of the marked improvement in credit conditions is that asset-backed commercial paper has re-emerged as an investment alternative with some issues trading at levels better than pre-crisis rates. The volatility of the Canadian equity market is also now around its historic mean based on the market's expectation of how volatile the stock market will be relatively over the next month. We conclude that the credit crisis is over in Canada and does not impact our recommendations.

Concerns going forward include: sovereign debt crisis spillover effects; weak economic growth in the U.S. and Europe; and an ongoing structural fiscal challenge at the provincial level (particularly, Ontario). In contrast, strengths going forward include: the favorable impact of higher commodity prices; reasonable growth in China and India; and quicker resolution of ongoing federal budget deficits than was previously anticipated.

1.3.4 Capital structure recommendations for OPG Hydro and Nuclear

In the final section, Section 5, we update and extend our analysis that underpins our capital structure recommendations for each type of OPG's regulated assets originally presented in our evidence in EB-2007-0905. We begin with a brief overview of the practical implication of capital structure theory that no formulaic approach can be used for determining capital structure. Thus, as in EB-2007-0905 and consistent with business practice, we adopt a heuristic approach for determining the business risk input into the determination of appropriate capital structures for the regulated assets of OPG and its two "divisions" (namely, Hydro and Nuclear). Our analysis leads to the conclusions that the business risks of these two "divisions" are materially unchanged since EB-2007-0905. We analyze the bond ratings, capital structures (both actual and allowed), interest coverage ratios and returns on equity for a sample of eight traded Canadian utilities.

Based on these examinations and tests, we arrive at a recommendation for the appropriate equity ratio for each segment of OPG. We assess the business risk faced by OPG Hydro as low to moderate – higher than that of a distribution utility and somewhat above the business risk of an integrated electric utility. This suggests that a fair common equity ratio for OPG Hydro should be at 40%, which is just below the middle of the range of common equity ratios that we find for our comparisons. We set the recommended equity ratio at this level to account for our benchmark of allowed equity ratios being generous. In contrast, our analysis rates the business risk of OPG's regulated nuclear assets as moderate and greater than that of OPG Hydro. Following similar logic, and taking into account a marginal upward adjustment from the level determined in our EB-2007-0905 evidence, we continue to maintain 50% as the fair level of equity for OPG's nuclear assets. These individual equity percentages are consistent with the overall equity thickness for the combined regulated entity of 47% recommended in our 2008 Evidence and adopted by the Board.

To show that our recommendations of 40% equity for OPG Hydro and 50% for OPG Nuclear are not incompatible with a rating in the A range, we calculate the implied values of three metrics considered by bond rating agencies using the forecast data provided by OPG in its Application. We conclude that our recommendations of 40% and 50% equity for Hydro and Nuclear respectively are in the A range (i.e. A- to A).

2. CASE FOR MAINTAINING CURRENTLY ALLOWED EQUITY THICKNESS AND RETURN ON EQUITY FOR OPG'S AGGREGATE REGULATED OPERATIONS

2.1 Decisions of the OEB

In its EB-2007-0905 Decision, the OEB determined that the cost of capital for OPG's aggregate regulated operations:

- should be consistent with the stand-alone principal (pages 140 to 142);
- reflect the "adoption of a formula approach to setting the ROE" (page 162); and
- reflect differences in OPG's relative (business) risk for its aggregate regulated operations in its capital structure (page 162).

The OEB set OPG's allowed ROE at 8.65 per cent effective April 1, 2008. Based on the Board's view that "OPG's regulated nuclear business is riskier than regulated distribution and transmission utilities in terms of operational and production risk, but is less risky than merchant generation" (page 149), the Board prescribed a 47 per cent common equity ratio (page 149) for OPG's aggregate regulated operations.

In EB-2009-0084, the OEB prescribed a reset and refined adjustment mechanism for setting the ROE for rate-regulated utilities that submitted a cost of service rate application for rates effective on or after 2010. One of the reasons given by the OEB for these changes was that (page 33):

> The Board notes that while the current formula today produces results similar to that in 2008, it does not address the observed behaviour of the formula during the financial crisis – lowering the allowed ROE when the amount and price of risk in the market was increasing.

Based on an assumed forecast of the bond yield of long Canada's of 4.25% and a generic (low risk) utility-specific risk premium of 5.5 per cent (including 50 bps for transactional costs), the Board (page 37) set the initial ROE to be embedded in its reset and refined ROE formula at 9.75% (i.e. 4.25% + 5.50% = 9.75%). The reset and refined ROE adjustment formula for the prospective test year was given as follows:

$$ROE_t = BaseROE + 0.5x(LCBF_t - BaseLCBF) + 0.5x(UtilBondSpread_t - BaseUtilBondSpread)$$

where: *BaseROE* is the base for the ROE adjustment formula (i.e. 9.75%);

BaseLCBF is the Long Canada Bond Forecast for the base year (i.e. 4.25%);

BaseUtilBondSpread is the spread in 30-year A-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield (i.e. 1.415%); and

LCBF is the average of the 3- and 12-month yield forecasts of 10-year Canada's published in *Consensus Forecasts* 3 months prior to the rate implementation + the average business day spread of 30-year A-rated Canadian utility bonds or *UtilBondSpread* over 30-year Canada's for the month that is 3 months prior to rate implementation.

Thus, the ROE increases/decreases with both increases/decreases in the proxy for the risk-free rate and for the proxy for the investment risk of the long-term debt of an average A-rated Canadian utility.

2.2 OPG's Application

In its EB-2010-0008 application (Exhibit C1, Tab 1, Schedule 1, page 1), OPG is seeking:

> "approval of the test period cost of capital as presented in Ex. C1-T1-S1 Tables 1 and 2. In determining the cost of capital, OPG has applied the capital structure of 47 per cent equity and 53 per cent debt approved by the OEB in EB-2007-0905. OPG has applied the ROE of 9.85 per cent set by the OEB for use in 2010 cost of service applications in the OEB's letter of February 24, 2010."

OPG goes on to state that (Exhibit C1, Tab 1, Schedule 1, page 3, lines 6-12):

> "For 2011 and 2012 OPG has adopted the results of the OEB's Cost of Capital Report. The Cost of Capital Report establishes a revised base ROE and a modified automatic ROE adjustment mechanism. Given that the revised base ROE and the refined automatic ROE adjustment mechanism represent the same concepts that were adopted for OPG's prescribed assets in EB-2007-0905, both are applicable to OPG at the approved capital structure and appropriate to the business risks of the prescribed assets."

2.3 Critique

A compelling reason to base the current evidence on the ROE derived from the formula is the Board's statement that its "intention was to review capital structure, and not return on equity" (Procedural Order No. 3, page 8). In line with that intention, we are not submitting detailed evidence on the return on equity for OPG. Nonetheless, we provide a brief commentary on the formula as context to support our conclusion that it continues to provide a generous return for the combined entity.

The first issue that we address is the expansion of the adjustment mechanism to include a factor for bond spreads for A-rated utilities. As highlighted below, the economic and financial crisis prevailing at the time when the OEB rendered its Decision EB-2009-0084 had some impact on the Board's Decision. While the OEB clearly stated that "the sum of the elements supporting the Board's decision to reset and refine its formulaic ROE is independent of the recent financial crisis and whether or not the crisis has abated" (page 34), it did judge the adequacy of the previous formula in light of the crisis as noted above. We interpret the addition of a spread term as an attempt to provide for the impact of a future crisis, in case one occurs. We comment briefly on this spread term addition both in light of academic research in this area and practical impact.

Beginning with the academic perspective, Drs. Elton, Gruber, Agrawal and Mann (2001) provide estimates of the size of each component of the credit spread (namely, the default spread, tax spread, and risk premium) for investment-grade corporate bond portfolios. Consistent with other credit-spread studies, they find that default risk accounts for only a small portion of credit spreads and a residual systematic risk factor accounts for the majority of the variation in credit spreads. Consistent with their results, the third term in the reset and refined ROE adjustment formula attempts to hold default risk constant by using the credit spread for 30-year A-rated Canadian utility bonds. Thus, the major driver of the third term would be changes in a systematic factor such as market liquidity that has a credit cycle component.

Turning from the academic perspective to the practical impact of the formula, we note that the third term is asymmetrically distributed since it is truncated at -1.415% if the current *UtilBondSpread* became zero and is unbounded given that there is no upper bound on *UtilBondSpread*. In practical terms, this property would allow utilities governed by the formula to receive an unlimited increment to their required return in the event of a crisis while limiting the reduction in ROE in the event that market conditions became unusually benign.

Looking beyond the formula, it is also possible to judge the fairness of the range of returns on equity it produces. In this regard, the reset BaseROE of 9.75% and the utility-specific equity risk premium of 5.5% embodied in it for the regulated operations of an A-rate utility (i.e. a low risk firm) most comfortably satisfy the Fair Return Standard. We provide two illustrations. First, we compare these values to the return expectations for the Canadian market as proxied by the S&P/TSX Composite (an average risk firm) and for Long Canada's based on a survey of investment professionals conducted by Towers Watson during November 2009. These findings are summarized in Schedule 2.1. We find that both the reset BaseROE of 9.75% and the utility-specific equity risk premium (ERP) of 5.5% are marginally below their corresponding median counterparts for the market as a whole of 10% and 5.7% for a short-term (2010) horizon, substantially above their corresponding median counterparts of 8.0% and 3.0% for a mid-term horizon (2011-2014) and substantially above their corresponding median counterparts of 8.0% and 2.7% for a long-term horizon (2015-2024). The reset BaseROE of 9.75% exceeds the median return expectation for the S&P for all three horizons.

Second, we compare the utility-specific ERP of 5.5% to the realized MERPs for the Canadian and U.S. markets for various periods in Schedule 2.2. For all four periods, the reset utility-specific ERP of 5.5% is considerably higher than that for the market which has a higher risk than an A-rated regulated utility. This is even the case for the period with the highest MERPs (namely, the 110-year period, 1900-2009) of 3.7% and 4.2% for Canada and the U.S., respectively.

To reach a conclusion on fairness, we note that our comparisons are between equity risk premiums and ROEs for utilities as against comparable values for the Canadian and U.S. equity markets as a whole. In Section 4 we show that utilities in general and OPG in particular have low levels of business risk. Further, in past evidence in recent hearings we have consistently demonstrated that the level of systematic risk measured by beta (total risk) for an average Canadian utility is approximately half that of the market (an average firm in the market). Based on these risk assessments, the finding that the BaseROE and implied utility ERP exceed those of the higher-risk market equivalents leads us to the conclusion that the Board's formula continues to provide a generous return for regulated utilities.

3. CASE FOR SETTING SEPARATE EQUITY THICKNESSES FOR OPG'S NUCLEAR AND HYDROELECTRIC OPERATIONS

3.1 Decisions of the OEB

The Board's finding in the previous proceeding (EB-2007-0905) on separate capital structures for the regulated hydroelectric business and the nuclear business is found on page 161 of the decision with reasons. Specifically:

> "The Board concludes that this is an approach worthy of further investigation which will be explored in OPG's next proceeding. In examining whether to set separate costs of capital, the Board intends only to examine whether separate capital structures should be set for the regulated hydroelectric and nuclear businesses. The Board expects that the same ROE would be applicable to both types of generation. This is consistent with the general approach of setting a benchmark ROE and recognizing risk differences in the capital structure.
>
> The Board recognizes that this approach will not alter the overall cost of capital for OPG's prescribed facilities. However, in all other significant respects the specific costs [of] the hydroelectric and nuclear businesses are used to derive the specific payments for each type of generation. Specific and separate costs of capital for hydroelectric and nuclear would be consistent with the separate nature of these businesses and would provide a more transparent link between the payment amounts for each type of generation and the underlying costs."

3.2 OPG's Application

In its EB-2010-0008 application (Exhibit C1, Tab 1, Schedule 1, page 1, lines 15-25), OPG states that it hired Foster Associates Inc. ("Fosters") to examine the feasibility of determining separate costs of capital for its regulated nuclear and hydroelectric facilities as directed by the Board. Ms. McShane in the Fosters report (included as Ex.

C3-T1-S1 in OPG's application) concluded that none of the cost of capital methodologies that she examined yielded a robust and analytically sound basis for specifying technology-specific costs of capital. OPG also argued that it continues to support the use of a single cost of capital for its prescribed facilities because this approach was used in the last application and this approach is "consistent with the manner in which OPG is actually financed".

3.3 Critique

Both OPG and Ms. McShane argue against the application of different costs of capital for OPG's regulated nuclear and hydroelectric operations. Since neither OPG nor Ms. McShane provide any of the arguments in favor of determining different capital structures and by extension different costs of capital for OPG's regulated nuclear and hydroelectric facilities, we begin with that discussion.

3.3.1 The arguments for divisional costs of capital

The major advantage of using divisional costs of capital when divisional risks differ is to ensure that the scarce resource of capital is allocated efficiently (referred to as "allocational efficiency"). To explain this concept, we suppose that a utility has two regulated divisions, such as nuclear and hydro electricity generation, and that nuclear is more risky. It follows then that the cost of capital ordering from lowest to highest would be hydro, the firm and then nuclear due to their different levels of risk. Thus, when evaluating the desirability of an investment opportunity that has a risk similar to the average-risk of the capital assets already in place in each division using the net present value (NPV) criterion, each division should discount the stream of expected cash flows at its *divisional* cost of capital. If each division instead uses the utility-wide cost of capital as the discount rate, then nuclear would accept some investment projects that should have been rejected and hydro would reject some investment projects that should have been accepted. Thus, the utility will have accepted bad high-risk projects and rejected good low-risk projects.

The same logic applies if the utility and its two divisions use the internal rate of return (IRR) criterion to evaluate the desirability of investments. Using this approach, an investment is acceptable if its IRR is not less that the applicable cost of capital (referred to as the "cutoff" or "hurdle" rate). If the multidivisional utility uses a firm-wide hurdle rate for the evaluation of its investment opportunities, the utility will accept some bad high-risk projects and reject some good low-risk projects because its hurdle rate will be too high for low-risk divisions and too low for high-risk divisions.

A secondary effect of not using such risk-adjusted discount or hurdle rates is the feedback effect on the rate-setting process. As a utility using a company-level discount or hurdle rate over time commits to investments that are biased towards bad high-risk projects for nuclear and away from good low-risk projects for hydro. The weights of the nuclear and hydro divisions thus become respectively higher and lower than they would have been if their divisional costs of capital had been used. In turn, the increased risk will lead to a higher utility-level cost of capital over time.

The bottom line is that even less precise estimates of divisional capital structures and costs of capital are preferable to pretending that there are no differences in both measures between divisions when it has already been acknowledged that such differences exist.

3.3.2 The arguments against divisional costs of capital

We now address each argument presented in the OPG application against the adoption of separate capital structures and costs of capital for OPG's regulated nuclear and hydroelectric operations.

3.3.2.1 OPG's evidence

In its EB-2010-0008 application (Exhibit C1, Tab 1, Schedule 1, page 1, lines 15-25), OPG states that it continues to support the use of a single cost of capital for its prescribed facilities because this approach was used in the last application. With due respect, we fail to see the logic behind this argument. Setting divisional capital structures and costs of capital that result in the same OPG-level capital structure and cost of capital is not inconsistent with the approach used in the last application.

In its EB-2010-0008 application (Exhibit C1, Tab 1, Schedule 1, page 1, lines 15-25), OPG states that it continues to support the use of a single cost of capital for its prescribed facilities because this approach is "consistent with the manner in which OPG is actually financed". However, under the "pool-of-funds" approach to utility funding and capital allocation, the utility-level cost of capital reflects the "average" risk of the utility's assets in place and this cost of capital should be used to evaluate its average-risk investment opportunities. Since the addition of higher risk investments into the assets in place at the utility level increases its "average" risk (all else held constant), these higher risk investment opportunities need to be assessed using a higher (risk-adjusted) cost of capital.

OPG position is in opposition to its position presented to the consultative process for the treatment of infrastructure investment where it argued that:

> "Whether or not a given infrastructure investment qualifies for the modified treatment should be based on whether the investment represents increased risk over other projects in the entity's portfolio, not by who happens to be proposing them."[2]

It summarized its position as: "Accordingly, OPG reiterates that infrastructure investments should be evaluated based on increased risk."[3]

[2] Comments of Ontario Power Generation Inc. on the staff discussion paper on the regulatory treatment of infrastructure investment (EB-2009-0152), July 7, 2009, page 3.
[3] Comments of Ontario Power Generation Inc. on the staff discussion paper on the regulatory treatment of infrastructure investment (EB-2009-0152), July 7, 2009, page 4.

In its response to Pollution Probe's Interrogatory 016, OPG states that it uses the same discount rate of 7% in its financial analysis for all investments with respect to Prescribed Assets, and that risks are taken into account in the cash flows.[4] OPG prescribes distributions for various input variables and uses a Monte Carlo simulation to generate a cumulative probability distribution, which they refer to as an S-curve, for its evaluator variable(s), which in the case of the Darlington Refurbishment results in a LUEC (Levelized Unit Energy Cost).[5] It is not obvious from its application how OPG deals with the contemporaneous interrelationships between the input variables and the tendency of simulation to underweight tail observations. To evaluate the sensitivity of the Darlington LUEC, for example, OPG conducts a sensitivity (and not a more robust scenario) analysis using the "low and high ends of these ranges for each of the key input Factors".[6] To evaluate the sensitivity of the Darlington LUEC, for example, OPG has a range for the discount rate of 7% plus or minus 1%.[7] It finds that the results of the Updated Economic Assessment are most sensitive to five input factors, where the fifth factor is the discount rate.[8] While specifying the S-curve for factor inputs reflects the uncertainty associated with those factor inputs, it does not account for the project risks.

However, the traditional purpose of a Monte Carlo simulation is to determine the project's business risk and thus its appropriate risk-adjusted discount rate. Therefore, the most appropriate discount rate to use in a Monte Carlo simulation is the risk-free rate of interest since it adjusts for the time value of money and not for risk.[9] The appropriate risk

[4] OPG's Response to Pollution Probe Interrogatory #016, EB-2010-0008, Issue 3.3, Exhibit L, Tab 10, Schedule 016.
[5] Transcript, Technical Conference, August 26, 2010, line 3, page 169 to line 10, page 170.
[6] Ontario Power Generation, *Economic Feasibility Assessment of Darlington Refurbishment*, November 13, 2009, EB-2010-0008, Exhibit D2-2-1, Attachment 4, page 33 of 35.
[7] Ontario Power Generation, *Economic Feasibility Assessment of Darlington Refurbishment*, November 13, 2009, EB-2010-0008, Exhibit D2-2-1, Attachment 4, page 34 of 35.
[8] Ontario Power Generation, *Economic Feasibility Assessment of Darlington Refurbishment*, November 13, 2009, EB-2010-0008, Exhibit D2-2-1, Attachment 4, page 33 of 35.
[9] Pioneering studies in the use of Monte Carlo Simulation for the assessment of capital projects include: Mr. D.B. Hertz, Investment policies that pay off, *Harvard Business Review* 46: 1 (January-February 1968), pages 96-108; and Drs. Lawrence Kryzanowski, Peter Lusztig and Bernhard Schwab, Monte Carlo Simulation and capital expenditure decisions – A case study, *The Engineering Economist* 18:1 (1972), pages 31-48. A less technical description of the use of Monte Carlo Simulation for project analysis is found in: Drs. Lawrence Kryzanowski, Devinder K. Gandhi and Lawrence J. Gitman, *Principles of Managerial Finance* (New York, Harper & Row Publishers, 1982), pages 480-482.

premium should then be added to the risk-free rate after the determination of the project's business risk to determine the project's appropriate risk-adjusted discount rate.

In its EB-2010-0008 application (Exhibit C1, Tab 1, Schedule 1, page 1, lines 15-25), OPG states that the Fosters report (included as Ex. C3-T1-S1 in OPG's application) concluded that none of the cost of capital methodologies that were examined by Ms. McShane yielded a robust and analytically sound basis for specifying technology-specific costs of capital. We now address that evidence.

3.3.2.2 Ms. McShane's evidence

3.3.2.2.1 Ms. McShane's evidence: Overview

Most of Ms. McShane's analysis concentrates on whether meaningful market model betas could be calculated using various methodologies and samples of U.S. utilities that are not differentiated by the proportion of their electricity generation that was nuclear or hydro. Thus, Ms. McShane evaluated a number of methodologies that have been utilized for estimating the cost of equity that is used in the determination of the divisional costs of capital *when the capital structure is known or can be obtained independently*. Instead, Ms. McShane should have examined differences in divisional debt capacities (e.g. equity thicknesses). The task at hand is not to calculate separate allowed rates of return on equity for nuclear and hydro but to determine the capital structures for each "division".

If one calculates the divisional equity beta or the cost of equity using an analytical approach, one must somewhat use that information to determine the divisional capital structures. Ms. McShane describes her conversion process as follows: "To the extent required by the analysis, the conversion of differences in the cost of equity among proxy samples into capital structure equivalents will be based on the premise that the overall cost of capital is constant across the relevant range of capital structures".[10] This

[10] Kathleen McShane, Technology-specific capital structures: An assessment, Exhibit C3-1-1, page 3.

ATWACC approach invokes the unrealistic assumption that ATWACC (or the overall cost of capital) is the same for each utility used in the estimation (even if their bond ratings vary from BBB- to A). This will result in divisional equity ratios with large estimation errors and unknown biases.

However, this is interestingly the approach that Ms. McShane used to derive her capital structure recommendation for OPG at the benchmark return in EB-2007-0905.[11] In that evidence, she used the residual beta model, which she now concludes is not robust in her current evidence, to derive a generation-only levered beta from the high generation sample. The model then included the levered beta for "wires" operations estimated from a sample of utilities with primarily "wires" operations and an assumed levered beta for "other" operations that was assumed to be 1.0 (i.e. equal to the beta of an average risk stock or the market). In her evidence filed in EB-2007-0905, she thus used a more judgmental approach to conclude that OPG's regulated operations were not subsidizing its unregulated operations.[12]

Consistent with our evidence in EB-2007-0905, we recommend that the determination of divisional capital structures is best achieved using a two-step procedure where the first step is to determine divisional debt capacities (e.g. equity thicknesses) if both nuclear and hydro are allowed the same generic rate of return on equity. Consistent with our evidence in EB-2007-0905, we recommend that the first step is best implemented using a heuristic-based approach. Then, the calculation of the divisional cost of capital for nuclear and hydro for OPG in the second step is fairly straightforward. The Board appears to have agreed with the result of our judgmental approach in Decision EB-2007-0905 (pages 149-150):

> "The Board concludes that the recommendation of Drs. Kryzanowski and Roberts, namely an equity ratio of 47%, is appropriate in the circumstances. This ratio is higher than the equity ratio of any other regulated Ontario energy utility, thereby recognizing the higher risk of OPG."

[11] Evidence of Ms. McShane, EB-2007-0905, Exhibit C2, Tab 1, Schedule 1, pages 91-97.
[12] Evidence of Ms. McShane, EB-2007-0905, Exhibit C2, Tab 1, Schedule 1, page 97.

3.3.2.2.2 Ms. McShane's evidence: Analogies

Ms. McShane dismisses the use of a sample of Canadian utilities because all "four conventionally structured publicly traded companies in Canada with significant amounts of generation that are either regulated or governed by contractual arrangements which have cost of service characteristics" are relatively diversified with "no significant amount of hydroelectric capacity" and only one "owns any nuclear capacity".[13] She also dismisses the use of a sample of Canadian utilities structured as income trusts as being "problematic from a cost of capital perspective due to the change in the *Income Tax Act* announced by the Department of Finance in the 2006 Tax Fairness Plan". This dismissal is based on her untested conjecture that "the reaction of the capital markets to the announcement would have an impact on market measures of risk (e.g. beta) that is unrelated to the fundamental operating risks to which the underlying assets of the trusts may be subject." However, empirical evidence contradicts Ms. McShane's conjecture: Dr. Kryzanowski and Ms. Lu report that the betas did not change significantly after this announcement for 29 business income trusts.[14]

The U.S. samples used by Ms. McShane suffer from many of the problems involved in selecting matching or proxy samples. For example, her sample of 44 U.S. electric utilities used in the instrumental variables analysis have mean and median S&P debt ratings of BBB+ and BBB, respectively.[15] The failure to address carefully how the sample risk differs from that of Canadian utilities is particularly problematic as Ms. McShane previously pointed out these very differences. In EB-2007-0905, Ms. McShane provided various reasons why a rating lower than A would not be appropriate for OPG, including "[o]f particular concern would be that a BBB rated utility would, at times, be completely shut out of the long-term (30-year) debt market".[16]

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[13] Ms. Kathleen McShane, Technology-specific capital structures: An assessment, Exhibit C3-1-1, page 37.
[14] Dr. Lawrence Kryzanowski and Ms. Ying Lu, In government we trust: Rise and fall of Canadian business income trust conversions, *Managerial Finance* 35: 9 (September 2009), pages 784-802.
[15] Ms. Kathleen McShane, Technology-specific capital structures: An assessment, Exhibit C3-1-1, Schedule 3, page 1.
[16] Evidence of Ms. McShane, EB-2007-0905, Exhibit C2, Tab 1, Schedule 1, page 80.

Furthermore, Ms. McShane makes no adjustments for a number of transactions involving the exchange of existing nuclear power plants since 1999. These include:

- In July 2005, FPL Energy agreed to pay $380 million for 70% of the Duane Arnold BWR (600 MWe capacity) from an Alliant Energy subsidiary, which continued to buy the power;
- In July 2006, Entergy agreed to buy the 798 MWe Palisades nuclear power plant from CMS subsidiary Consumers Energy for $242 million plus $83 million for the fuel and $55 million for other assets;
- In December 2006, FPL Energy agreed to buy the Point Beach nuclear plant (two units for a total 1012 MWe) from Wisconsin's We Energies, who continues to buy the power from the nuclear plant; and
- In December 2008, the bid by Electricité de France (EDF) was accepted for half of the nuclear business of Constellation Energy, which consisted of two reactors at Calvert Cliffs in Maryland, two reactors at Nine Mile Point in New York and the Ginna reactor in New York.

As stated earlier, her evidence focuses on the cost of equity traditionally used in valuation. Given this emphasis, it is surprising that she did not make any inferences from these valuation data.

3.3.2.2.3 Ms. McShane's evidence: Analytical approaches for divisional beta estimation

As a prelude to testing the applicability of various approaches for estimating divisional betas, Ms. McShane examines the time-series behavior of the mean nonstandard beta (i.e. adjusted towards the market beta of one) obtained from Value Line for a sample of 28 U.S. electric utilities from 1997 to 2009. Based on this examination, she concludes:

> "The instability of betas from measurement period to measurement period may be problematic for analyses that attempt to measure differences in return requirement for investments exposed to fundamentally different levels of business and/or financial risk."[17]

Deriving such a conclusion based on a price (and not return) beta is inappropriate for a sample where the dividend yield represents a material portion of the total return. Checking the Glossary on the Value Line website, we find that the Value Line beta is derived from a 5-year regression between the relationship of the weekly percentage changes in the New York Stock Exchange Composite Average and the weekly percentage changes in the <u>price</u> of the stock with no adjustment for dividends. As such, the Value Line beta is a measure of the sensitivity of price changes for a utility to price level changes of the market proxy, and is not a measure of the sensitivity of the total returns for a utility to the changes in the total returns of a market proxy.

As Ms. McShane notes for the electric utility business, "there are few, if any, companies that operate in a single function, i.e., regulated distribution, transmission or generation".[18] In turn, this effectively eliminates the use of the "pure-play",[19] "residual beta" and "instrumental beta" approaches to estimate a divisional equity beta for publicly traded companies and severely diminishes the efficacy of using the "full information" approach to estimate divisional betas. Considering this flaw together with the mis-targeted objective of the evidence (i.e. to estimate divisional capital structures and not equity betas), we pay little attention in our evidence to the various econometric problems implicit in her implementations of the various analytical approaches for divisional beta estimation with the exception of the full information approach.

With regard to the "full information" approach, there are several problems with its implementation by Ms. McShane where she uses each utility's levered beta in the cross-

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[17] Ms. Kathleen McShane, Technology-specific capital structures: An assessment, Exhibit C3-1-1, page 49.
[18] Ms. Kathleen McShane, Technology-specific capital structures: An assessment, Exhibit C3-1-1, page 40.
[19] Other "analogy" approaches calculate divisional betas from industry betas. For example, Drs. R.A. Brealey and S.C. Myers, S.C., *Principles of corporate finance*, 5th edition, New York: McGraw-Hill, 1996.

sectional regressions to obtain a leveraged beta for each division. A conceptual problem arises because her implementation makes two untenable implicit assumptions; which are aptly stated in a journal article as follows:

> "Since we estimate a single beta for each line of business in which a division may be engaged, we must implicitly assume that the same capital structure is embedded in the estimated divisional beta for all the multidivisional firms in the sample. But if capital structure affects beta, this can be true only if all multidivisional firms finance their divisions exactly the same way. Actually, our method also assumes implicitly that two multidivisional firms operating in the same combination of lines of business will have the same firm-level capital structure. Clearly, neither of these implicit assumptions is likely to be true in practice."[20]

While the estimation of divisional unlevered betas using the utility-level unlevered betas avoids this conceptual problem, one needs to assume that either the Modigliani and Miller or Hamada formula is appropriate for converting the utility-level levered betas into unlevered betas for conducting the cross-sectional regressions. One also needs to assume that either formula is also appropriate for converting the divisional unlevered beta estimates obtained from the cross-sectional regressions into divisional levered beta estimates. These latter computations require that we know the divisional capital structures, although this is what we are supposed to be estimating here.

Furthermore, a missing variables problem occurs if not all lines of business are included in the cross-sectional regressions. Since these missing variables are likely to be correlated with the error term of the regressions, the estimated coefficients will contain a bias of unknown magnitude.

3.3.2.2.4 Ms. McShane's evidence: DCF divisional equity cost estimation

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[20] Drs. Jess Chua, Philip C. Chang and Zhenyu Wu, The full-information approach for estimating divisional betas: Implementation issues and tests, *Journal of Applied Finance* (Spring/Summer, 2006), pages 53-61.

When Ms. McShane used the constant growth model for each year 2006-2009 to obtain cost of equity estimates, she obtained her expected cost of equity ordering from lowest to highest as being Wires, then High Generation and finally High Nuclear. This is not surprising given that the DCF model is arguably the most important model for determining allowed rates of return on equity in the U.S. for regulated utilities. Furthermore, there is an analytical approach for deriving betas from earnings growth regressions.[21] While a number of conceptual and implementation issues limit the usefulness of the DCF constant growth model in this application, given that she chose to estimate the model, it is surprising that Ms. McShane did not provide any divisional capital structure estimates based on the divisional costs of equity derived from this approach.

3.3.2.2.5 Ms. McShane's evidence: Lone judgmental approach for divisional capital structure estimation

Ms. McShane only examines one approach (i.e. judgmental) for estimating divisional capital structure. This heuristic-based approach for "establishing technology-specific capital structures on the basis of differences in business risk" uses S&P and Moody's guidelines to assess the reasonableness of utility capital structures.[22] She concludes:

> "While the S&P guidelines may be useful for assessing the reasonableness of utility capital structures, they provide little or no guidance for the specification of technology specific capital structures.
>
> ...
>
> Although the Moody's guidelines do apply specifically to regulated companies, in contrast to the S&P guidelines, their usefulness for the estimation of technology-specific capital structures is similarly limited. Significant judgment would be required to infer the implied ratings that Moody's would assign on a stand-alone basis to each

[21] Drs. Myron J. Gordon and Paul J. Halpern. Cost of capital for a division of a firm, *Journal of Finance* 29 (1974), pages 1153–64.

[22] Ms. Kathleen McShane, Technology-specific capital structures: An assessment, Exhibit C3-1-1, page 62.

of the business risk factors. However, as with S&P, while the guidelines provide a perspective on differences in capital structure which may be warranted for different levels of business risk from a debt investor's point of view, they do not address return requirements from an equity investor's perspective."[23]

However, the four reasons that she presents for why these guidelines "provide little or no guidance for the specification of technology-specific capital structures" are equally applicable to the determination of capital structure at the OPG-level.

3.3.2.2.4 Ms. McShane's evidence: Heuristic approaches not considered

Heuristic-based approaches are used by practitioners to deal with unobserved systematic risk measures when estimating the cost of capital for divisions that are not publicly traded.[24] Both approaches described below are two-step processes. The firm-level cost of capital is estimated in the first step, and this total cost is then adjusted to a divisional basis using the aggregate subjective rating of a division's risk relative to the mean-centered aggregate firm-level risk for a predefined list of specific risk criteria. Although the implementation is different, these approaches are conceptually similar to that employed in Section 4 of this evidence.

3.3.2.2.4.1 BCG's implementation of the heuristic-based approach

The implementation of the heuristic-based approach by the Boston Consulting Group (BCG) rates the risk of a division relative to that at the firm-level using six criteria and a five-point scale (see Schedule 3.1). The aggregate firm-level score is normalized at 18 (i.e. median score of 3 times 6 criteria). The aggregate score at the divisional level can range from 6 to 30 with scores above (below) 18 indicating that the division is more (less) risky than the firm. The normalized aggregate score at the divisional level is

[23] Ms. Kathleen McShane, Technology-specific capital structures: An assessment, Exhibit C3-1-1, page 64 and 65.

[24] This section is drawn from Drs. Juergen Bufka, Oliver Kemper and Dirk Schiereck, A note on estimating the divisional cost of capital for diversified companies: An empirical evaluation of heuristic-based approaches, *The European Journal of Finance* 10 (February 2004), pages 68-80.

obtained by dividing the original aggregate score at the divisional level by 18 so that a normalized aggregate score at the divisional level above (or below) 1 indicates that the division is more (or less) risky than the firm as a whole. Using a linear extrapolation, the divisional cost of capital equals the firm-level cost of capital multiplied by the divisional normalized aggregate score. Other weighting schemes are possible, and the logic behind this approach can be transferred to making adjustments to firm-level debt capacity to obtain divisional debt capacity estimates.

3.3.2.2.4.2 Fuqua Industries approach

Fuqua Industries is a U.S. company with 20-plus divisions that has also developed a multi-stage approach for the estimation of divisional costs of capital that uses multidimensional screens.[25] Fuqua adjusts the firm-level cost of equity based on the CAPM with two risk measures: (i) variability of operating profit using comparisons of forecasted operating profits for the current and subsequent year against the most recently completed year; and (ii) the normalized aggregate divisional risk score, whose only difference from the BCG approach is that it has 14 (different) criteria (see Schedule 3.2). Its application is the same as for the BCG approach. Again, other weighting schemes are possible, and the logic behind this approach can be transferred to making adjustments to firm-level debt capacity to obtain divisional debt capacity estimates.

3.4 Use of Non-Canadian Analogies

To assess the feasibility of using non-Canadian analogies for benchmark purposes, we obtained the proportions of total electric power generated from various fuels in various countries that is reported in Schedule 3.3. When we use a double screen that at least 10% of the electric power must be generated by nuclear and by hydro, we are left with only two countries, Finland and Sweden. Countries with more traditional return regulation, such as Australia, the U.K. and the U.S., do not meet the double-screen criterion.

[25] Drs. Benton E. Gup and Samuel W. Norwood, Divisional cost of capital: A practical approach, *Financial Management* 11: 1 (Spring, 1982), pages 20-24.

Countries such as Germany rely materially on nuclear but not hydro, and countries such as New Zealand rely materially on hydro but not nuclear.

Two countries satisfy our double screen. The four nuclear reactors in Finland that are owned by two utilities provide around 30% of the electricity in Finland. The Finnish Government has a controlling interest in both of these owners. Furthermore, the production and supply of electricity has been deregulated since the *Finnish Electricity Market Act* went into effect in November 1995. Similarly, with the deregulation of its electricity market on January 1, 1996, Sweden joined Norway to form the wholesale market Nord Pool. The membership of Nord Pool was later expanded to include Denmark and Finland. Nord Pool sets the price of electricity based on supply and demand bids. Due to their deregulated environments and state control ownership in Finland, we conclude that Finnish and Swedish utilities are questionable analogies for the purposes of our testimony.[26]

4. ECONOMIC AND FINANCIAL MARKET CONDITIONS

To provide a back-drop for the business risk assessment in the fifth section of our evidence, we now briefly review the economic performance and prospects in Canada, the U.S. and Ontario.

4.1 Economic Performance and Prospects in Canada

We first examine the economic performance and expectations for Canada drawn from the July 2010 issue of *Consensus Forecasts*. While GDP growth was minimal in 2008 at 0.5% and dismal in 2009 at -2.5%, the consensus forecast is for more normal growth of 3.5% and 2.8% in 2010 and 2011. The growth rate in machinery and equipment investment was absent in 2008 at -0.9% and dismal in 2009 at -20.3%. However, the consensus forecast is for more normal growth of 4.0% and 7.2% in 2010 and 2011. In

[26] Ms. McShane raises a number of the same concerns in her response to a Board Staff Interrogatory (see EB-2010-0008, Issue 3.3, Exhibit L, Tab 1, Schedule 017).

2008, pre-tax corporate profits were robust at 8.0% and dismal in 2009 at -32.3%, and the consensus forecast for 2010 and 2011 is for robust growth of 23.7% and 10.3%. While CPI was higher in 2008 at 2.4% and near deflation in 2009 at 0.3%, the consensus forecast is for an increasing rate of growth of CPI of 1.9% and 2.2% in 2010 and 2011. The federal budget deficit of -$5.8 bn CAD in 2008 and an estimated -$45.0 bn CAD in 2009 is expected to continue in 2010 and 2011 at -$40.1 bn CAD and -$26.3 bn CAD respectively.

As noted above, the time-series evolutions of two particular series (i.e. the re-pricing of corporate bond risk and the term premium) are of interest. Schedule 4.1 contains two relevant figures. The top figure contains a plot of the credit spreads for 30-year A-rated Canadian utility bonds over 30-year Canada's and the term premium of 30- over 20-year Canada's for the period from March 5, 2002 through July 28, 2010. Most of the gap between current A-rated Canadian utility credit spreads and where they were prior to the credit crisis has closed. Current A-rated 30-year Canadian utility credit spreads are still about 25.5 basis points above their historical mean for the studied period.

Examining spreads does not capture the downward trend in yields for both bond rating categories (i.e. 30-year A-rated Canadian utility bonds and 30-year Canada's) over the studied period depicted in the bottom figure of Schedule 4.1. The figure also shows the two series moving in opposite directions during the credit crisis but now moving in the same direction.[27] The percentage yield to maturity on a diversified index of investment grade Canadian corporate bonds is the lowest in at least 16 years.[28] Going forward, the expected strengthening of the Canadian economy, expected increases in inflation and continuing budgetary deficits are expected to increase yields on government bonds to more "normal" levels and further reduce credit spreads.

[27] The correlation between the two series increases from 0.67 to 0.82 when the months from September 2008 to February 2009 are deleted.
[28] John Heinzl, Bond investors pile into corporate debt despite yields, *Globe and Mail*, Thursday, August 26, 2010, page B9.

ABCP or asset-backed commercial paper has re-emerged as an investment alternative with some issues trading at levels better than pre-crisis rates. Some issues are trading at about 10 bps below the CDOR (Canadian dealer offered rate or average rate of Canadian bankers' acceptances), which is the benchmark for floating rate issues.[29]

The average volatility of the overall Canadian equity market at the daily close of 15.88% for July 2010 (ending with July 28) is below its full-period mean of 19.01% (see the time-series plot in Schedule 4.2). The volatility of the Canadian market is measured using the Montreal Exchange's Volatility Index (MVX), which reflects the market's expectation of how relatively volatile the stock market will be over the next month. The MVX is calculated from current prices of at-the-money options on the iShares of the CDN S&P/TSX 60 Fund (Ticker symbol: XIU).

Concerns going forward, which include spillover effects from the sovereign debt crisis in Europe, weak economic growth (or a double dip recession) in the U.S. and Europe and a ongoing structural fiscal challenge at the provincial level (particularly, Ontario) due to rising health costs, are contrasted against the favorable impact of higher commodity prices, reasonable growth in China and India and the Conference Board's prediction that federal budget deficits will end one year earlier than planned.[30]

4.2 Economic Performance and Prospects in the United States

We now examine the economic performance and expectations for the United States. While GDP growth was minimal in 2008 at 0.4% and dismal in 2009 at -2.4%, the consensus forecast is for more normal growth of 3.1% and 3.0% in 2010 and 2011 respectively. In 2008, business investment was minimal at 1.6% and dismal in 2009 at -17.8%, but the consensus forecast is now for low growth of 3.0% in 2010 and more

[29] Based on Tim Kiladze, ABCP-on-the-comeback-trail, *Globe and Mail*, Tuesday, July 27, 2010. Available at: http://www.theglobeandmail.com/globe-investor/investment-ideas/abcp-on-the-comeback-trail/article1652513/?cmpid=rss1.
[30] Glen Hodgson and Matthew Stewart, Canadian Feds Ahead of Plan on Fiscal Rebalancing, *Hot Topics in Economics*, Conference Board of Canada, July 29, 2010. Available at: http://www.conferenceboard.ca/economics/hot_eco_topics/default/10-07-29/Canadian_Feds_Ahead_of_Plan_on_Fiscal_Rebalancing.aspx.

normal growth of 8.0% in 2011. Similarly, growth in pre-tax corporate profits was dismal at -11.8% and -3.8% in 2008 and 2009 respectively. However, the consensus forecast is for robust growth of 23.1% and 6.6% in 2010 and 2011. While the CPI growth rate was higher in 2008 at 3.8% and in deflation in 2009 at -0.3%, the consensus forecast is for moderate growth of the CPI of 1.7% and 1.5% in 2010 and 2011. The federal budget deficit of -$459 bn USD and -$1,417 bn USD in respectively 2008 and 2009 is expected to continue in 2010 and 2011 at -$1,335 bn USD and -$1,181 bn USD.

Concerns going forward include spillover effects from the sovereign debt crisis in Europe, constrained household consumption, weakening inflation, continuing depressed housing market, increasing government debt levels and the possibility of a W-shaped and not a V-shaped economic recovery. However, these concerns are contrasted against stronger market demand in Asia and emerging markets and accommodating fiscal and monetary policies.

4.3 Economic Forecast for Ontario

In 2009, Ontario's economic performance was one of the worst among the provinces with real GDP shrinking by 3.1% in contrast with a smaller decline of 2.5% for Canada.[31] This reversed in 2010 with a revival in the manufacturing sector led by increased demand for housing and strong auto production. To illustrate, based on improved performance in sales in June 2010, Scotiabank recently raised its full-year 2010 sales forecast for vehicles from 1.525 million to 1.565 million units. According to BMO Capital Markets, real GDP of Ontario is expected to grow 3.4% this year before slowing to below-average growth compared to other provinces in 2011. Due to the sharp decline in GDP resulting from the global recession, Ontario real GDP is expected to remain below its pre-recession level until the first quarter of 2011. The activities in the manufacturing and exports sectors, although much recovered from 2008 and 2009 levels, are likely to remain well below peaks seen this past decade owing to the strong Canadian dollar.

[31] Our forecasts are from BMO Capital Markets, Economics Research, *Provincial Monitor*, June 2010; Scotiabank Group, Global Economics Research, *Provincial Trends*, June 16, 2010 and Auto News Flash, August 4, 2010; and RBC Economics, *Provincial Outlook*, June 2010.

Service sector employment has risen to a record level with the private sector creating 120,000 jobs during the past year. The unemployment rate in Ontario peaked in the manufacturing sector but due to service jobs growth, the unemployment rate is forecasted by RBC Economics as 8.7% for 2010 and improving to 7.9% for 2011. Household income advanced by 1.3% in Q1, 2010 reflecting increased employment and strong earnings in the quarter while personal disposable income increased by 0.7% and personal consumption expenditure rose by 1%.

The housing market was strong in the first half of 2010 due to low mortgage rates and pre-HST buying, but this market is currently slowing down (e.g. house prices in Toronto fell 3.3 % in July and sales fell 34% in July compared to June despite low interest rates and a fully loaded inventory).

5. CAPITAL STRUCTURE RECOMMENDATIONS FOR OPG HYDRO AND NUCLEAR

5.1 Overview of this Section

This section updates and extends our discussion of capital structure for each type of OPG's regulated assets originally presented in our evidence in EB-2007-0905. Following the same outline, we begin with a brief overview of the practical implications of financial theory for our analysis of the appropriate capital structure for OPG. Our main conclusion is that, although no generally accepted formula exists for setting capital structure, the level of equity should increase with the degree of business risk. This provides the conceptual underpinning for our adopting a heuristic approach.

To implement this approach, we next review the business risks faced by OPG hydro assets (OPG Hydro) and nuclear assets (OPG Nuclear) separately. As in our 2008 evidence, our review of market, operational and regulatory risks leads to the conclusion that OPG's regulated hydro business carries low to moderate risk (1.8 on a scale of 5 where 1 is the lowest risk and 5 the highest). In contrast, OPG's regulated nuclear generation has a higher level of business risk that we assess as approaching moderate (2.6 on our 5-point scale). We review factors that could potentially cause a change in these levels of business risk and conclude that the risks are materially unchanged since EB-2007-0905.

In order to gain perspective on these measures of business risk, we briefly compare them against the risks of generic electricity transmission and distribution businesses as well as those of integrated electric utilities. This allows us to benchmark our recommendations for OPG against capital structures allowed by this Board and by other Canadian regulators for other companies in these categories. Our approach also facilitates comparisons with our own analysis in prior testimony. We assess the average risk for transmission as low (1 on our 5-point scale). We also study the business risk associated with generic distribution and rate it as low to moderate (1.4 on our scale). Based on these inputs, we assess the business risk of an integrated company by taking an asset-weighted average of the risks of OPG hydro, generic transmission and generic distribution. Our analysis sets the business risk of an integrated electricity company at 1.5 on our scale or low to moderate.

We then turn to examining relevant financial data for a sample of eight Canadian gas and electric utilities and pipelines that have publicly traded common shares chosen to be consistent with our past evidence in which we required the included companies to be publicly traded. We analyze bond ratings, capital structures, interest coverage ratios and returns on equity for our sample companies.

Drawing on the basic principle that the level of equity in the deemed capital structure of a utility should reflect its business risk and combining our risk assessments and benchmarks, we conclude that business risk is unchanged since the Decision in EB-2007-0905 for both divisions and the total regulated OPG. Our analysis of benchmarks contains nothing to suggest that the benchmark levels used in our 2008 Evidence require revision. In that Evidence we concluded that being considerably riskier than a generic transmission and somewhat riskier than an integrated company or a generic distribution company, OPG hydro should carry a higher level of equity than any of these three comparators. We assigned 40% as the appropriate equity ratio for OPG's hydro assets. Following similar logic, and taking into account a marginal upward adjustment from the level determined in our EB-2007-0905 Evidence, we continue to maintain 50% as the fair level of equity for OPG's nuclear assets.

These individual equity percentages are consistent with the overall equity thickness for the combined regulated entity of 47% recommended in our 2008 Evidence and adopted by the Board.

5.2 Implications of Financial Theory

Finance theory has several important implications for setting the appropriate level of the equity ratio for a regulated electric utility. First, theory teaches us to be suspicious of attempts to determine an appropriate equity ratio using a formula. Unlike other areas in finance, research on capital structure can offer only qualitative policy advice. To quote a leading, current corporate finance textbook:

> "No exact formula is available for evaluating the optimal debt-equity ratio."[32]

While we expect an introductory textbook to contain an element of simplification in order to present material to beginning students, this statement has yet to be superseded by advanced research.

This important implication of finance theory provides the conceptual foundation for our use of a heuristic approach in setting capital structures – a methodology that has been accepted by Canadian regulators, including this Board as well as the Alberta Utilities Commission (formerly the Alberta Energy and Utilities Board). In Decision 2004-052, page 35, the AUC wrote:

> "In the Board's view, setting an appropriate equity ratio is a subjective exercise that involves the assessment of several factors and the observation of past experience. The assessment of the level of business risk of the utilities is also a subjective concept. Consequently, the Board considers that there is no single accepted mathematical way to make a determination of equity ratio based on a given level of business risk."

The Commission took the same approach in its 2009 Generic Cost of Capital AUC Decision 2009-216 (November 12, 2009), pages 88-89:

[32] S.A. Ross, R.W. Westerfield, J. F. Jaffe and G.S. Roberts, *Corporate Finance*, 5th Canadian Edition, Toronto: McGraw-Hill Ryerson, 2008, page 500.

"... the Commission will first consider the record of the Proceeding on the overall risk of regulated utilities posed by the current credit environment and current utility credit metrics. The Commission will then assess, on the basis of the record of the Proceeding, the risk of each of the utility sectors and determine a relative ranking of risk for each sector and the commensurate equity ratio that, in the Commission's judgment, will allow the utilities in each sector to maintain the desired credit rating. Finally, the Commission will turn to an assessment of each individual utility to determine whether specific adjustments to each company's equity ratio are warranted."

The OEB similarly endorsed a qualitative, heuristic approach in its Decision in EB-2007-0905 at page 136:

"The Board finds that the approach to setting the capital structure should be based on a thorough assessment of the risks OPG faces, the changes in OPG's risk over time and the level of OPG's risk in comparison to other utilities."

Although it does not offer a formula, finance theory does highlight key considerations in determining capital structure. In the same textbook we find the following:

"How should companies establish target debt-equity ratios? While there is no mathematical formula for establishing a target ratio, we present three important factors affecting this ratio:

- Taxes. As pointed out earlier, firms can only deduct interest for tax purposes to the extent of their profits before interest. Thus, highly profitable firms are more likely to have larger target ratios than less profitable firms.
- Types of assets. Financial distress is costly, with or without formal bankruptcy proceedings. The costs of financial distress depend on the types of assets that the firm has. For example, if a firm has a large investment in land, buildings, and other tangible assets, it will have smaller costs of financial distress than a firm with a large investment in research and

development. Research and development typically has less resale value than land; thus, most of its value disappears in financial distress. Therefore, firms with large investments in tangible assets are likely to have higher target debt-equity ratios than firms with large investments in research and development.

- Uncertainty of operating income. Firms with uncertain operating income have a high probability of experiencing financial distress, even without debt. Thus, these firms must finance mostly with equity. For example, pharmaceutical firms have uncertain operating income because no one can predict whether today's research will generate new drugs. Consequently, these firms issue little debt. By contrast, the operating income of utilities generally has little uncertainty. Relative to other industries, utilities use a great deal of debt [emphasis added]."[33]

Taken together, these three factors are central to establishing the appropriate amount of debt for a utility. In particular, factors 2 and 3 determine the level of business risk that restrains the company's use of debt in order to reduce the cost of financial distress and the probability that such distress will occur due to low operating income. Turning from speaking in general about any company to focusing on a regulated electric utility, we believe that factors 2 and 3 are largely mitigated by the special features of this industry.

For a regulated electric utility, the costs of financial distress (factor 2) are reduced because its assets make excellent collateral. Further, the regulation process virtually ensures that the company will recover its debt payments and other costs. Further, regulation allows the company to go back to its regulator to apply for relief in the unlikely event that it does not earn its fair rate of return in a given year, and especially if its ability to service its debt were in jeopardy. Additionally, in the extreme event that an electric utility became insolvent, it is highly likely that the regulator (and other governmental bodies) would work with the company to find new investors or a merger partner so that service (and thus, asset usage) would not be interrupted. This is what

[33] S.A. Ross, R.W. Westerfield, J. F. Jaffe and G.S. Roberts, *Corporate Finance*, 5th Canadian Edition, Toronto: McGraw-Hill Ryerson, 2008, page 502.

occurred with the bankruptcy of Pacific Gas and Electric Company in California.[34] As a result, the cost of financial distress is far lower than for a non-regulated firm.

The third factor is the probability of financial distress. As stated in the quotation, this probability is low for utilities because operating income has low variability, which is further diminished if the utilities make extensive use of deferral accounts.

The special nature of regulated utilities was clearly reflected in the 2008 decision by S&P to change its application of notching criteria for U.S. utility companies from relative to absolute, and to increase the rating of the senior unsecured debt of 32 utilities to be the same as each utility's corporate credit rating, even when a considerable amount of secured debt is outstanding.[35] The press release states on page one that:

> "... our criteria have evolved so that the notching analysis can also focus on the value of assets available in a bankruptcy and whether those assets are sufficient to satisfy claims, regardless of the debt's priority. This approach is beneficial for the debt ratings of utilities because the value of their regulated assets is resilient and because their ability to add debt is restricted. As a result, creditors of defaulted utilities have realized higher average recovery rates than the creditors of companies in other sectors."

The press release provides the following justification for this change on page two:

> "In our view, this conclusion and the recovery prospects of unsecured regulated utility obligations benefit from several unique factors. First, utility assets are more likely to retain value in a bankruptcy scenario because of the essential nature of the service those assets provide. The experience of pure utility defaults (albeit few

[34] K. Gaudette, Bankrupt Pacific Gas and Electric hopes to avoid state laws, Associated Press, *The Nando Times*, January 25, 2002. Available at: www.nando.net/business/story/228567p-2199342c.html.
[35] Standard and Poor's, Criteria | Corporates | Utilities: Notching Of U.S. Investment-Grade Investor-Owned Utility Unsecured Debt Now Better Reflects Anticipated Absolute Recovery, November 10, 2008. Available at:
http://www2.standardandpoors.com/portal/site/sp/en/us/page.search/search/0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0.html.

in number) shows that bankruptcy is normally caused by management missteps that lead to regulatory problems that in turn constrain cash flows. The situation is rehabilitated in the post-bankruptcy restructuring in a way that leaves regulated asset values essentially intact.

Second, most utilities must obtain regulatory permission to issue new debt, and this requirement acts as a constraint on the utilities' ability to add debt in the event of a default spiral.

Third, utility mortgage indentures restrict the issuance of FMBs to a percentage of bondable property, as defined in the indenture. The bondable property definition is normally tied to a utility's physical plant, and the percentage is typically 70% or less. Other indenture provisions may be more expansive, but usually not to a significant degree. These industry-specific and jurisdictional factors indicate that in most distressed situations we can reasonably anticipate recovery above 30% for utility unsecured debt."

In conclusion, we come back to the beginning of our answer to this question. If we set aside factors 2 and 3 (i.e. the costs of financial distress and the probability of financial distress), the theory suggests that a company should use a high proportion of debt. Our comments on factors 2 and 3 explain why it makes sense to expect these factors to carry less importance in practice for this industry. With the focus then on the first factor, taxes, we would expect regulated electric utilities to be among the most highly leveraged industries.

We now turn from electric utilities as an industry to examine the business risk of OPG both on its own and relative to that of other sectors of the industry.

5.3 Business Risk of Ontario Power Generation

5.3.1 Framework for analysis

Our assessment of business risk focuses on uncertainty of operating income introduced earlier in our overview of important factors in the determination of capital structure. Factors that increase costs to a utility such as higher fuel prices do not necessarily translate directly into increased business risk. Management can prevent these factors from increasing the uncertainty of operating income in several ways. First, it can forecast their impacts and build them into proposed pricing. In a fair regulatory environment, such costs will be allowed and passed on to customers. Second, management can engage in risk mitigation to control the impact of such factors on operating income. Third, risk can be mitigated by use of deferral accounts. Business risk is only increased to the extent that these three approaches to control risk only work incompletely.

Our analysis of business risk begins with an examination of the risks of hydroelectric and nuclear generation for OPG. Drawing on our 2008 Evidence, we introduce each of the three major categories of business risk for utilities: market, operational and regulatory, and discuss each in detail first for the regulated hydro and then for the nuclear operations of OPG. Our discussion presents a detailed breakdown of the components of business risk within each category and a numerical ranking of each on a scale of low (1), moderate (3) or high (5). We create a summary table, Schedule 5.1, displaying the rankings of each of nine individual risks covering our three categories. Our conclusion is that the regulated hydro generation activities of OPG carry a low to moderate level of business risk (i.e. 1.8 on our 5-point scale, with a score of 1 representing low risk and 5 the highest risk for a utility). The regulated nuclear operations are rated as approaching moderate risk (2.6 on our 5-point scale).

Our use of a scoring model is validated by research documenting the effectiveness of quantitative credit scoring and its widespread use by financial institutions for assessing the credit risk of loans to individuals and small businesses.[36] For these small loans, large

[36] A.N. Berger, W.S. Frame and N.H. Miller, Credit scoring and the availability, price and risk of small business credit, Federal Reserve Bank of Atlanta Working Paper No. 2002-6. Available at SSRN:

sample sizes allow the development of quantitative scoring. As detailed above, for application to divisions within a company, smaller numbers make it more appropriate to employ a qualitative approach. This approach is commonly applied to utilities. For example, Standard & Poor's identifies five factors on which it bases its business risk assessments for utilities: regulation, markets, operations, competitiveness and management. Examination of ratings reports from DBRS and Moody's confirms that these agencies address the same factors in appraising business risk.

To provide perspective on our business risk rankings, we next use our framework to measure the business risks of other sectors of the utilities industry and explain why we agree with the commonly held view that transmission (wires) carries the lowest business risk followed by distribution and then by generation with the highest business risk. We assess the business risk of transmission utilities as low (score of 1 out of 5) and distribution utilities as somewhat higher at low to moderate (1.4). These assessments form the basis for our capital structure recommendations for OPG Hydro and OPG Nuclear below. The analysis of business risks in the transmission and distribution sectors provides the basis for comparisons with deemed capital structures in those sectors.

5.3.2 Business risk of OPG's regulated hydroelectric generating assets

5.3.2.1 Market Risk

Market risk is the risk that a hydro generator will not be able to meet its target sales due to weak markets, to competition or to other related factors. However, OPG is the market leader in Ontario accounting for 71% of the electricity sold in 2007.[37] DBRS expects that the company will retain this position for the near future as well as after 2014 – the target date for closing coal-fired generation facilities. As discussed in Section 4, the Ontario economy is recovering in 2010 and expected to continue slow growth in 2011 led

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http://ssrn.com/abstract=315044 or DOI: 10.2139/ssrn.315044. L. Kryzanowski, M.C. To and Roger Seguin, 1990, Chapter 4: An analytical framework for the assessment of solvency risk, ***Business Solvency Risk Analysis*** (Montreal: Institute of Canadian Bankers, Volume 1, Revised September 1990).

[37] Our discussion draws on Ontario Power Generation, ***Ratings Direct***, Standard & Poor's, October 16, 2009 and April 30, 2010 and DBRS Rating Report, August 12, 2009.

by manufacturing and service sector employment. The province experienced long-term growth of annual electricity consumption peaking in 2005 and declining through 2009 as a result of the impacts of conservation and a slowdown in economic growth, particularly in industrial production. In the near term, the IESO is predicting a modest increase in energy use in 2010 and continued slow growth out to 2014 consistent with the economic forecast summarized earlier. After 2014, the IESO is calling for a moderate decline that will return usage to 2009 levels by 2018.[38] Since the regulated part of OPG is a base-load, low marginal cost generator, it is not expected to experience a significant level of demand or dispatch risk as noted by the Board in its EB-2007-0905 Decision at page 147. Standard & Poor's reached the same conclusion:

> "OPG's strong competitive position in the Ontario wholesale electricity spot market is founded on its market dominance and the low marginal operating costs of its hydroelectric and nuclear generating facilities. If the company lost its regulatory support, it would have little, if any, dispatch risk for these baseloaded assets. Although there are other independent generators participating in the Ontario wholesale spot market, the demand for energy and capacity is such that all nuclear and most hydroelectric generators have relatively modest exposure to dispatch risk."[39]

In addition, competitive cost structure and transmission limitations protect OPG from competitive supply threats from Quebec and Manitoba. We thus assign a rating of low (1 out of 5) for competition / demand risk as shown in Schedule 5.1.

Our view of competition/demand risk disagrees with that of Ms. McShane in two respects. First, her forecast of electricity demand is overly pessimistic as it is based on dated sources: she limits her comments on the Ontario economy to quoting the Ministry of Finance's 2009 *Ontario Economic Outlook and Fiscal Review* released on October 22, 2009 and the IESO's *18-Month Outlook from December 2009 to May 2011* published

[38] *Ontario Reliability Outlook*, Independent Electricity System Operator (IESO), December 2009, www.ieso.ca.
[39] Ontario Power Generation, *Ratings Direct*, Standard & Poor's, October 16, 2009, page 11.

November 17, 2009 (Technology Specific Capital Structures: An Assessment, Kathleen C. McShane, 2010-0008, Exhibit C3-1-1, page 24). These sources document Ontario's economic decline in 2009 and state that "the economic recovery is unlikely to stimulate a significant rebound in electricity demand". More current IESO material quoted earlier projects modest growth consistent with economic recovery documented in Section 4 of this evidence. Ms. McShane accepts that the outlook is more positive in her response to Pollution Probe Interrogatory #031 (Exhibit L, Issue 3.1, Tab 10, Schedule 031, page 1).

Second, Ms. McShane overstates the impact of green legislation on page 25:

> "Subsequent to the 2008 regulated payments proceeding, the Ontario government passed the Green Energy and Green Economy Act, to position Ontario as a world leader in green energy. The legislation created a Feed-in Tariff program (replacing the previous Renewable Energy Standard Supply Program); the Feed-in Tariff program provides for attractive long-term contractually guaranteed prices for wind, hydroelectric, and biomass projects, designed to attract additional new investment in the renewable energy sector. The development of green energy projects under the Feed-in Tariff program will potentially lead to an increasing occurrence of surplus baseload generation. The adoption of the Green Energy and Green Economy Act and the potential softening of demand support the conclusion that the dispatch risk to which OPG's regulated operations are exposed is rising."

The concern over the impact of green legislation is not shared by DBRS and S&P: a search of the rating documents turned up no reference to this legislation. This is likely the case for two reasons. First, green energy, aside from hydroelectricity, is a minor component of Ontario supply. In response to part a of Pollution Probe Interrogatory #032, Ms. McShane identifies "renewable generation under contract with the OPA supplied generation [as] equivalent to 3 percent of Ontario demand in 2009 and anticipates that renewable generation under contract with the OPA will supply generation equivalent to 9 percent of Ontario demand in 2011."[40] Second, in her response to part b of

[40] Response to Pollution Probe Interrogatory No. 032 (Exhibit L, Issue 3.1, Tab 10, Schedule 032).

the same Pollution Probe Interrogatory, Ms. McShane agrees that "increased dispatch risk ... represents an increased forecasting risk" and such risk is mitigated by deferral accounts. As she states in her response to part b of Pollution Probe Interrogatory #033:

> "The use of deferral and variance accounts mitigates forecasting risks related to costs over which the utility has little or no control, or are difficult to forecast. The extent to which deferral accounts lower the forecasting risk is a function of the scope of the accounts and the materiality of the costs that are covered by those accounts. The existence of such accounts does not, however, guarantee recovery of the costs nor does it change the utility's fundamental risks."[41]

A related component of market risk is the credit risk that may arise if a utility's customers default on their payments. This element of market risk is also low (1 out of 5) for OPG because it does not sell directly to ultimate power users.

With competition/demand risk and customer credit risk both rated low, we conclude that market risk is low (1 out of 5) for OPG's hydro generation business.

5.3.2.2 Operational Risk

Operational risk represents the risk that OPG will not meet production and profitability targets. We identify four elements of operational risk and discuss them in turn. We also discuss how deferral accounts serve to mitigate the various elements of operational risk. The first component of operational risk is operating leverage which arises when operations such as hydro generation are characterized by a high level of fixed costs, which make operating cash flow more sensitive to changes in production. We assess operating leverage as moderate (3 out of 5) in Schedule 5.1. Related to operating leverage, advanced technology also impacts fixed costs and makes production more sensitive to technical breakdowns. We assign a risk rating of low to moderate (2 out of 5) to technology risk.

[41] Response to Pollution Probe Interrogatory No. 033 (Exhibit L, Issue 3.3, Tab 10, Schedule 033).

Capacity risk relates to forced outages due to unanticipated breakdowns or prolonged maintenance. Hydroelectric generation is typically subject to a low rate of forced outages. Capability factors measure reliability as the ratio of available energy generation to reference energy generation defined as production under full power. Available energy generation may fall below reference levels due to "limitations within control of plant management, i.e., plant equipment and personnel performance, and work control" according to the International Atomic Energy Agency.[42] In a regulatory perspective, such a shortfall does not constitute a risk for which a utility should be compensated. OPG continues its traditional record of high capability factors for its hydro units.

Further, hydro generating units are not subject to the risk of increasing fuel costs as are fossil fuel and nuclear units. Nor do they fall prey to significantly increased risks of environmental compliance. However, availability of water does create a production risk as lower water levels could reduce output and create unrecovered costs. Historically, water availability has not been a problem for OPG due to its diversification of regulated hydro assets on two river systems (i.e. the St. Lawrence and Niagara Rivers).[43]

Further, OPG currently has a deferral account (Hydroelectric Water Conditions Variance Account) which allows the company to collect cost recovery in years with lower water levels and to replenish the account when water levels are above forecast.

In addition, OPG is requesting a new deferral account to be called the IESO Non-Energy Charges Variance Account (Exhibit H1, Tab 3, Schedule 1, Page 8 of 9). This account will address variances in charges to wholesale customers that are difficult to forecast and can be material. These include charges for Debt Retirement Charges, Rural Rate Assistance, Transmission Charges, and Global Adjustment among others. According to OPG:

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[42] *Financing of new nuclear power plants*, IAEA Nuclear Energy Series, No NG-T-4.2, International Atomic Energy Agency, Vienna, 2008. Available at: www.iaea.org.
[43] *Corporate Credit Rating*, Standard & Poor's, October 16, 2009.

> "... the Global Adjustment – typically the largest of all non-energy charges – exhibits substantial variability month over month. It represents the difference between the total payments made to certain contracted or regulated generators and conservation and demand management projects, and any offsetting market revenues."[44]

Considering all the elements of capacity risk produces a rating of moderate (3 out of 5). The presence of a water deferral account mitigates capacity risk and leads to a rating of low risk (1 out of 5) under deferral accounts.

A further aspect of operational risk arises from costs that can arise from the obligatory retirement of assets and construction of new generation. For its hydro generation, environmental issues related to asset retirement are not a major concern as they are for coal burning and nuclear units. Hydro generators do face risks with regard to capital expenditures. However, the recovery of fixed capital costs such as depreciation is included in the allowed rate and addressed by a capacity refurbishment variance account to cover variances to forecasts during the test period. Longer term, DBRS believes that these risks will be largely mitigated by financial structuring and regulation:

> "It is expected that OPG will not undertake any major capital projects without having its financing and a cost-recovery mechanism in place, thus minimizing the financial risks. Although OPG may be able to reduce its risks through fixed price contracts, the extent to which overrun risk can be placed on a contractor for large construction projects remains to be seen."[45]

In brief, our assessment of risks associated with asset retirement and construction leads us to conclude that this risk is low to moderate for OPG Hydro.

5.3.2.3 Regulatory Risk

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[44] EB-2010-0008, Exhibit F4, Tab 4, Schedule 1, Page 4 of 6.
[45] Ontario Power Generation Inc., *DBRS Rating Report*, August 12, 2009, page 3.

Regulatory risk can arise when costs are disallowed, allowed returns do not fit market expectations or rate design (including allowed capital structures) varies from what is fair and reasonable in view of business risks. Alternatively, regulation can mitigate risks through the introduction of deferral accounts and by allowing generous allowed returns and capital structures as discussed in other parts of this evidence.

We believe that regulation by the Board plays the second, positive role for OPG and assess the regulatory risk as low for a number of reasons. First, as discussed earlier, deferral and variance accounts allowed by the Board reduce operational risk. Second, as also explained above, we expect that the Board will approve appropriate structures that will mitigate the risk of future construction. Third, it is our understanding that the Board regulates in a fair manner. It follows that it is logically contradictory for the Board to recognize possible future political interference as a risk for which the company should be compensated:

> "The stand alone principle leads us to conclude that OPG's financial risks are not lower as a result of Provincial ownership; therefore it is consistent to conclude that political risk is not higher as a result of Provincial ownership (EB-2007-0905 Decision, page 142)."

Regulatory risk may also arise due to unanticipated shifts in environmental or safety regulations or in their enforcement. Because hydro generation does not involve the burning of fossil fuels or the potential dangers of nuclear generation, we rate this element of risk as low to moderate (2 out of 5).

5.3.2.4 Summary on Business Risk for OPG's Hydroelectric Assets

Our review assesses nine dimensions falling within the three main areas of business risk (market, operational and regulatory) and the ratings presented above are summarized in Schedule 5.1 in the column marked OPG Hydro. As the Schedule shows, the average-risk rating is 1.8, thus producing a low to moderate level of business risk for OPG's regulated hydro assets unchanged since Decision EB-2007-0905 in November 2008.

Notwithstanding her concern about dispatch risk which we addressed above, Ms. McShane reaches a similar overall conclusion regarding the business risk of these assets on page 26:

> "With the exception of a modest increase in dispatch risk during the test period due to the passage of the Green Energy and Green Economy Act and low demand conditions, the business risks faced by OPG's regulated hydroelectric operations remain largely unchanged since EB-2007-0905."

5.3.3 Business risk of OPG's regulated nuclear generating assets

5.3.3.1 Market Risk

Market risk is the same for nuclear as for hydro generation. Therefore, we assess both competition and customer credit risks as low for the reasons explained earlier.

5.3.3.2 Operational Risk

Nuclear technology is more advanced and characterized by a greater degree of fixed costs (operating leverage) and higher technology risk. We rate both as moderate to high (4 out of 5) and unchanged since the Decision in EB-2007-0905.

Nuclear generation is also subject to more intense environmental and safety regulations that create the potential for lengthy unplanned outages. In the case of OPG the greater risk of nuclear generation is magnified by issues related to unplanned maintenance and inspection outages.

Unpredicted fuel cost increases represent an added potential capacity risk to nuclear generation. In its Decision in EB-2007-0905 (page 33), the Board noted that the price of uranium increased up to mid-2007 and then fell sharply. This fall has continued: at the time of the Board Decision in November 2008, uranium was priced around $87 U.S. per pound while on August 3, 2010 the price was $46 U.S.[46] Further, it is only the unexpected component of any price increase that is a source of risk and OPG has two lines of defense against fuel cost risk. First, the company traditionally engages in fuel price hedging for both fossil and nuclear fuels. Second, uranium fuel price risk is covered by the nuclear fuel expense variance account approved by the Board in its EB-2007-0905 Decision.

As we noted earlier, the costs of decommissioning assets and disposing of used fuel are higher for nuclear than for hydro generation. For OPG, these risks are mitigated by funding of a Used Fuels Fund and a Decommissioning Fund under the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province. As stated in the EB-2007-0905 Decision at page 66:

> "Under the ONFA, the Province limits OPG's financial exposure for used fuel management with respect to the first 2.23 million used fuel bundles, a threshold that OPG expects will be reached in 2011. OPG is fully responsible for costs of managing used fuel bundles in excess of that amount. The Province also guarantees an annual rate of return of 3.25% above the Ontario Consumer Price Index on the portion of the used fuel fund related to the first 2.23 million used fuel bundles. Actual returns in excess of the guaranteed return accrue to the Province, not OPG."[47]

While DBRS takes a balanced view of waste and decommissioning costs rating the limit to OPG's liability as a Strength and the balance as a Challenge, the Board emphasized the risk reduction aspect:

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[46] Available at: http://www.infomine.com/.

[47] OPG has since revised its estimate of when the fuel bundle limit will be reached to 2012 (see EB-2010-0008, Exhibit C2, Tab 1, Schedule 1, page 6, lines 29-30.

> "Two significant protections related to the prescribed assets have been established by O. Reg. 53/05 and will be ongoing: changes in nuclear liabilities and refurbishment costs. These are significant additional protections which have been established by the government and exceed the level of protection typically granted to a regulated utility.
>
> The Board's conclusion is that these accounts do reduce risk. The Board notes, however, that under O. Reg. 53/05, amounts placed in the deferral and variance accounts after the Board's first order will be subject to a prudence review. These accounts will operate the same way for OPG as they do for other regulated entities, although the breadth of protection is greater."[48]

A further aspect of operational risk derives from the need to build new generation assets leading to financing challenges and construction risk. Because the largest proportion of OPG's planned future growth is in nuclear, this risk is higher than for hydro generation and is noted as a challenge by both DBRS and S&P. As indicated in our discussion of hydro risks, this risk is however mitigated through project structuring as well as by a capacity refurbishment variance account to cover variances to forecasts during the test period. There is also protection against long-term planning changes:

> "The Board is also required to ensure that OPG recovers the revenue requirement implications of changes in the nuclear liabilities Reference Plan and the costs of the refurbishment of the prescribed nuclear facilities. These represent a more extensive risk protection than might typically apply to a regulated utility. Although the nuclear liabilities are unique to OPG, the deferral account ensures that OPG is kept whole and the impact of any change in the Reference Plan is borne by customers."[49]

[48] Decision in EB-2007-0905 at page 141.
[49] Decision in EB-2007-0905 at page 148.

Deferral accounts moderate the operational risk of nuclear generation arising from waste disposal and capacity as discussed above. Rate structure can have the same effect. In particular, in the last hearing OPG requested a 25% fixed charge for nuclear generation. We agree with Ms. McShane (at page 27), that, had the Board approved the requested fixed charge, the effect would have been to mitigate operating leverage. The business risk assessment in our 2008 Evidence was based on the counterfactual assumption that the Board would approve the fixed charge. As a result, our prior assessment marginally understated the operational risk of OPG. We addressed this in our prior evidence referring to OPG's request for the fixed charge:

> "Should the Board deny this request the impact would be to reduce risk mitigation. In our framework, this falls under the deferral account category in the OPG Nuclear column Schedule 3.1. Under the scenario in which the Board disallowed OPG's request for a 25% fixed charge, business risk would be increased raising the rating for this category from Low (1) to Moderate (3)."

Recognizing that the Board did not approve the fixed charge we adjust the deferral account category as indicated.

In addition to increasing the risk of forced outages, as discussed earlier, higher technology risk also increases the risk associated with financing asset replacement as documented by the Director-General of the OECD Nuclear Agency:

> "It appears that there is very little likelihood at the present stage of development of nuclear technology and the nuclear construction industry to finance a new NPP by using non-recourse financing (where a stand-alone project company raises the capital it needs to build the plant using only the NPP project itself as collateral). Even for hybrid schemes which include a significant proportion of equity, debt investors at present are unlikely to be willing to provide significant funding for a

nuclear plant without recourse against the balance sheet of a strong and creditworthy utility."[50]

Summarizing our discussion of operational risk in OPG's nuclear assets, the company faces moderate to high levels of both operating leverage and technology risks both rated 4 out of 5. Its moderate (3 out of 5) exposure to capacity risk arises from aspects of nuclear generation outside of management control. Further, OPG faces moderate risk associated with decommissioning and construction. Finally, deferral accounts related to fuel costs and funds supporting used fuel and decommissioning costs partially mitigate the associated risks leading to a moderate rating (3) for deferral accounts.

5.3.3.3 Regulatory Risk

Regulatory risk associated with the primary regulator is subject to the same factors for nuclear as for hydro assets. The difference is that the stakes are higher due to the higher operational risk of nuclear generation. On this point we agree with Standard & Poor's, which states:

> "In our opinion, OEB regulation reduces uncertainty surrounding cost recovery and supports OPG's strong business risk profile but does not fully alleviate volume risk linked to nuclear output and available hydrology. Furthermore, OPG's nuclear segment is highly susceptible to poorer-than-targeted performance (aging assets), and cost overruns that, we believe, heighten regulatory risk."[51]

A further aspect of regulatory risk arises from OPG's request to increase nuclear payment amounts by including construction work in progress (CWIP) arising from the Darlington Refurbishment Project in the test period rate base. The factors to be considered by the OEB in considering such a proposal that are specified in EB-2009-

[50] How to Finance a Nuclear Program, Roundtable moderated by Luis Echavarri, OECD Nuclear Energy Agency, March 8, 2010.
[51] *Corporate Credit Rating*, Standard & Poor's, October 16, 2009, page 5.

0152 include "the cost of the project in proportion to the current rate base of the utility".[52] The rationale for this criterion is that including CWIP in rate base increases cash flow to assist utilities undergoing a large capital build in controlling challenges to their credit metrics arising from the need to grow their rate bases substantially. In the current case the cost is small relative to the rate base. Total generation capital associated with the Darlington Refurbishment is $105.2 M for 2010 and $255.8 M for 2012.[53] For the same test years, Rate Base Financed by Capital Structure is $6,321.4 M and $6,448.1 M, respectively. Assuming that CWIP is 100% of generation capital (which is optimistic) produces estimates of CWIP as being not more than 1.7% of rate base in 2011 and 4% in 2012. It follows that any impact on business risk arising from the possible allowance of CWIP for Darlington Refurbishment must come from other sources.

One possible such impact could be that regulatory risk associated with a possible disallowance of the initial costs could be reduced. This would occur because allowing CWIP for the initial stages of the project would be interpreted as a sign that the Board would allow the full costs even in the event that the refurbishment does not go ahead in 2014. To encourage the initial project by allowing CWIP in rate base and then denying full cost recovery could be interpreted as retrospective rate making and a departure from best regulatory practices. Second, an opposite effect of increasing business risk could also arise as, encouraged by the Board's approval of initial project CWIP, OPG could develop a bias in favour of refurbishment and decide to go ahead with the full project despite the fact that better, lower cost alternatives were available. In this scenario, the project would have a negative net present value thus increasing the business risk of OPG as a standalone entity.

In addition to any possible impact should CWIP be allowed, nuclear assets are subject to additional regulatory risks relating to environmental and safety regulation under the supervision of the Canadian Nuclear Safety Commission (CNSC). The CNSC regulates

[52] FIT was not an alternative mechanism that was considered or brought up in this consultative process. EB-2009-0152, Report of the Board, The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario, January 15, 2010, page 21.
[53] Response to Pollution Probe Interrogatory #014, EB-2010-0008, Exhibit L, Issue 4.5, Tab 10, Schedule 014.

Canada's seven nuclear power plants including those of OPG along with other nuclear reactors.[54] Due to the high level of regulation, it is possible that an enhancement to regulations or an unexpectedly strict interpretation by CNSC could cause unforeseen costs or unplanned outages at one of OPG's plants. Such a closure occurred at the Chalk River nuclear research facility operated by Atomic Energy of Canada Ltd. in November 2007. At issue was the classification of a redundant safety system as either an optional safety enhancement or a necessary condition of licensing.[55] Further, future legislation could impose more onerous safety regulations on OPG.

While we recognize that shifts in environmental and safety regulation do pose a risk to OPG in its nuclear operations, we assess this risk as moderate. Should the risk from shifts in environmental and safety regulation materialize, it can be mitigated by a deferral account in the same way that OPG is protected against changes to the nuclear liabilities Reference Plan.

In brief, our review of OPG's regulatory risk in its nuclear generation results in a rating of low regulatory risk with respect to the Board based on our earlier discussion of regulatory risk. Additional regulatory risk arises from possible shifts in environmental and safety regulations regarding nuclear operations but this is mitigated by the minor role currently played by this risk and the company's right to request a deferral account should the risk become material in the future. Overall, we assign a rating of moderate to this second aspect of regulatory risk arising from OPG's nuclear operations.

5.3.3.4 Summary of Business Risk of Nuclear Generation

Our review examines the three main areas of business risk (market, operational and regulatory) using nine dimensions. We summarize the ratings presented above in Schedule 5.1 in the column marked OPG Nuclear. As the Schedule shows, the average-risk rating is 2.6, thus approaching a moderate level of business risk for OPG's nuclear

[54] Available at: www.nuclearsafety.gc.ca.
[55] Peter Calamai, Medical isotope power struggle, Toronto Star, February 25, 2008. Available at http://www.thestar.com/news/canada/article/306604.

assets. As for OPG's hydro assets, we again conclude that the level of business risk is unchanged since the EB-2007-0905 Decision in November 2008.

Our qualititative assessment of the business risk of OPG's nuclear assets agrees with that of Ms. McShane. However, she goes on to discuss two aspects of the Board's ruling in that Decision which denied requests from OPG: rejection of OPG's request for a 25% fixed charge for nuclear production and setting a lower rate for the accretion of OPG's nuclear liabilities. As explained above, these denials are immaterial to the comparison of business risk since the Decision in EB-2007-0905. Our discussion of operational risk details how we updated our assessment to take into account the absence of fixed charges.

5.4 Relative Risks of Electricity Sectors

With our business risk analysis of OPG's hydro and nuclear generation complete, we now turn to an examination of the relative business risks of electricity transmission and distribution. Because there are a number of regulated companies in these sectors in Canada, such a comparison provides a useful perspective.

Market competition risk is low for transmission because of its status as a natural monopoly. While electricity distribution also has the characteristics of a monopoly it carries higher market competition risk due to the possibility of customers switching to natural gas or increasing reliance on co-generation. Further, because distribution companies sell to wholesale and retail customers, they face credit risk to a larger degree than do transmission companies whose sole customer is a distribution firm. More importantly, distribution companies are subject to operating leverage risk as they levy variable charges to cover fixed costs.

We summarize our view of the relative risks of electricity distribution and electricity transmission on the first page of Schedule 5.1. Using our risk rating criteria introduced earlier, the schedule shows the risk rating of electricity transmission as 1 or Low and distribution as 1.4 or Low-moderate. Our ranking is consistent with the opinion of the

Alberta Utilities Commission (formerly the Alberta Energy and Utilities Board) in EUB Decision 2004-052 (July 2, 2004) at page 48:

> "The Board notes the consensus that electric distribution companies are subject to more business risk than electric transmission companies, principally due to their recovery of a significant amount of fixed costs in variable charges and their greater exposure to credit risks."

The Commission restated this view in its Decision 2009-216 at page 98, paragraphs 370-371:

> "The Commission observes that there is a general consensus on the rank ordering of risk by sector. The electric transmission sector is considered to have the least risk. No party argued otherwise and the Commission agrees. The Commission also finds in general that the electricity distribution segment is slightly more risky than electricity transmission."

Electricity generation carries higher business risk than distribution along a number of dimensions. As explained above, because it is not a natural monopoly, generation faces potential competition from independent electricity producers locally as well as from generating facilities in neighboring provinces or states. Generation also carries a higher degree of operating leverage as a result of a higher level of fixed assets and more complex technology. On the production side, capacity risk arises from unplanned outages, fuel costs and water availability. Further electricity generators are subject to risks from unplanned costs of asset retirement and construction of new generating facilities.

Reinforcing our relative ranking of electricity generation as riskier than either transmission or distribution, their risk ratings in Schedule 5.1 are lower than those derived earlier for either division of OPG. Further, our view that generation is the riskiest sector is consistent with the thinking of the Board in its Decision in EB-2007-0905 at page 149:

> "The Board concludes that OPG's regulated nuclear business is riskier than regulated distribution and transmission utilities in terms of operational and production risk, but is less risky than merchant generation (for example, given the risk reduction afforded by some of the deferral and variance accounts)."

One additional useful business risk benchmark is the risk of an integrated utility, conducting generation, transmission and distribution business. To assess the business risk of such an entity we take a weighted average of the individual business risks. To illustrate, we take Emera as an example. In 2009, Emera reported total book value of assets of $2,933.7 million of which generation assets were $1,106.2 million, transmission $473.5 million, distribution $703.2 million and Other $224.2. Excluding other assets and calculating the percentage of each type of asset gives: 48.46% for generation; 20.74% for transmission; and 30.80% for distribution. To derive the business risk of an integrated company, we round these weights to 50% generation, 20% transmission and 30% distribution and apply each to the sector business risk as shown in Schedule 5.1. The calculation shows that the business risk of an integrated company is Low-moderate, i.e. higher than either transmission or distribution alone and lower than generation.

5.5 Bond Ratings and Capital Structures for Canadian Utilities

In this section, we examine the bond ratings and capital structures, both actual and allowed for a sample of Canadian utilities. Our purpose is to develop benchmarks of capital structures for different segments of the industry. With these benchmarks in hand, we can then draw on our analysis of business risk above to recommend an appropriate equity ratio for OPG Hydro, OPG Nuclear and for OPG's total regulated rate base. In the context of the Issues List in this Hearing, we focus on the individual equity ratios for OPG's two regulated divisions taking into account the overall equity ratio for the total regulated rate base as given at 47%.

Beginning with bond ratings, Schedule 5.2 displays Dominion Bond Rating Service (DBRS) and Standard & Poor's (S&P) bond ratings in August 2010 for our eight Canadian utilities and their regulated subsidiaries spanning different parts of the industry: gas, electric and pipelines. These companies represent a current sample of utilities with publicly traded shares. In forming this sample, we seek to measure ratings and financial ratios for the traded entity associated with the regulated utility. We recognize, however, that many of the traded companies include non-regulated businesses in addition to the regulated utility. We control for any bias by commenting on the differences as well as comparing our conclusions to those drawn strictly for regulated entities.

The bond ratings are from the websites of DBRS and S&P. Starting with the DBRS ratings, Schedule 5.2 shows that these range from A for Canadian Utilities, Enbridge, Newfoundland Power and TransCanada Corporation down to BBB (low) for Pacific Northern Gas. The Schedule shows that the typical Canadian energy utility is rated A (low) by DBRS. We next turn to the S&P ratings and make a similar comparison. The S&P ratings for the utilities in our sample range from A for Atco and Canadian Utilities down to BBB for Emera and TransAlta. S&P does not rate Pacific Northern Gas or the Fortis subsidiaries. The Schedule shows that the typical Canadian energy utility is rated A- by S&P.

The next step is to examine the actual, long-term capital structures of the companies in our sample for 2007 through 2009, the latest three years for which data are available in the *Financial Post Advisor* and company annual reports. These ratios show common equity, long-term debt and preferred shares as percentages of long-term capital excluding short-term debt. Focusing on the 2009 common equity ratios, Schedule 5.3 reveals that there is considerable variation across companies from a high of 52.67% for Pacific Northern Gas to a low of 34.95% for Fortis. The average percentage of common equity was 40.46% in 2009, which is down slightly from 41.76% in 2008. The equity ratio for these companies has been stable over the last three years.

In addition, Schedule 5.3 shows the percentages of long-term debt and preferred shares (separated from common equity) in the capital structures of these companies. Again, there was considerable variation in the proportionate use of financing across companies. On average, the companies employed 57.06% long-term debt and 2.48% preferred shares in 2009.

The presentation of ratios for the same group of companies continues in Schedule 5.4. The first three columns show the coverage ratio, EBIT/Interest expense.[56] The average coverage ratio was 2.65 times in 2009. The next three columns display cash flow to debt which averaged 16.42% in 2009.[57]

The schedules show that, from the vantage point of DBRS, Canadian Utilities, Enbridge, Newfoundland Power and TransCanada Corporation are the only companies which enjoy an A credit rating. The other companies are all rated A (low) or lower. For S&P, only two companies in our sample (ATCO and Canadian Utilities) are rated A. As stated earlier, the typical company is rated A (low) by DBRS and given an equivalent A-rating by S&P for its smaller set of ratings. Of the eight traded companies and five subsidiaries in our sample, six received a rating of BBB from at least one of the agencies. Yet, despite their lower ratings, with the exception of Pacific Northern Gas, a small company which experienced financial distress, these companies have had no difficulties in accessing capital markets to raise long-term financing. We conclude that the experiences of the companies in Schedules 5.2 - 5.4 suggest that a bond rating of BBB or higher is sufficient to maintain good access to capital markets.

Schedule 5.4 also contains data on ROEs for the companies in our sample which support our argument that a bond rating of BBB or above is sufficient for a regulated utility. The ROE figures for 2007 through 2009 show that all of the companies were profitable and earned positive ROEs in all three years.

[56] EBIT are earnings before interest and taxes.
[57] Cash flow from operations divided by the sum of long- and short-term debt. The result is expressed as a percentage.

Although the comparison is somewhat imprecise due to the inclusion of unregulated businesses in the traded companies, it is instructive to compare actual earned ROEs against the allowed ROEs set by regulators. A focus on the most recent year reveals that the actual ROEs earned by the parent holding company in 2009 exceeded ROE targets for 7 of the 11 regulated entities in Schedule 5.5 (i.e. all of the four ATCO regulated entities as well as Nova Scotia Power, Enbridge Gas and TransCanada Pipelines). Only four traded companies failed to earn the return on equity allowed for the regulated entity [i.e. three Fortis subsidiaries (Alberta, British Columbia and Newfoundland Power) and Pacific Northern Gas]. The average 2009 allowed return for this sample was 8.95%, while the average actual ROE for the consolidated company was 11.64%. The difference of 269 basis points represents the out-performance of allowed returns. This strongly suggests that having a bond rating of BBB did not impede these companies from profitably conducting their businesses.

5.6 Common Equity Ratio Benchmarks

Our discussion shows that the typical Canadian utility in our sample has a bond rating of A (low) from DBRS and A- from S&P. Further, a number of companies have BBB ratings. While OPG falls into this range with a bond rating of A (low) from DBRS and BBB+ from S&P, its bond rating is enhanced by the support it receives from the Province of Ontario. Further, ownership by the Province of Ontario impacts the goals of the company according to *The Government Backgrounder*, which stated:

> "The Ontario government has established prices for electricity produced by Ontario Power Generation (OPG) effective April 1, 2005. These prices are designed to:
>
> a) Better reflect the true cost of producing electricity
>
> b) Ensure a reliable, sustainable and diverse supply of power in Ontario
>
> c) Protect Ontario's medium and large businesses by ensuring rates are stable and competitive

d) Provide an incentive for OPG to contain costs and to maximize efficiencies

e) Allow OPG to better service its debt while earning a rate of return that balances the needs of customers and ensures a fair return"

Under the stand-alone principle of regulation, we must set aside the impact of provincial ownership of OPG and assess a fair capital structure from the standpoint of an investor-owned utility of comparable risk. This standard is provided by our sample in Schedule 5.2. Our analysis establishes that the sample represents a group of companies which, with appropriate adjustments discussed below, can proxy for the risk that would be faced by OPG if it were investor owned. Mindful of the goals set by the province but emphasizing the stand-alone principle, we use this sample to establish an appropriate capital structure for OPG.

5.6.1 Sample benchmarks

First, we turn to Schedule 5.3 where we observe that the average actual equity ratio for utilities in our sample was 40.46% for 2009, the most recent year for which we have data. This represents one useful benchmark for the equity ratio for a Canadian utility. Other benchmarks are helpful for two reasons. First, like any sample average, our average equity ratio depends on the sample drawn and can vary somewhat for this reason. Second, as we indicated earlier, the average is based on equity ratios for traded companies which include non-regulated activities which are likely to be more risky than regulated utilities. Academic research by Drs. Sanyal and Bulan documents the increase in business risk with U.S. deregulation which was accompanied by a decrease from 38% to 32% in the average book value equity ratio for U.S. electrical utilities (i.e. with deregulation, these companies do not have their leverage ratios set by regulators so these declines reflect adjustments to shifts in business risk).[58] Their paper demonstrates that for individual companies key factors explaining the decline in leverage were introduction of

[58] Sanyal, Paroma and Bulan, Laarni T., Regulatory Risk, Market Risk and Capital Structure: Evidence from U.S. Electric Utilities (August 1, 2008). Available at SSRN: http://ssrn.com/abstract=781230.

deregulation, uncertainties in the market environment in the absence of a safety net and the degree of competition.

As a check on our calculations, we examine the equity ratios allowed by various Canadian regulatory bodies for the companies in our sample for which we obtained data from past decisions. The sample includes ATCO Electric Transmission and Distribution, ATCO Gas and Pipelines, Enbridge Gas Distribution, Emera (Nova Scotia Power), Fortis Alberta, Fortis British Columbia, Maritime Electric, Newfoundland Power, Pacific Northern Gas, TransAlta, and TransCanada Pipelines. In Schedule 5.6, we report the average allowed equity ratio for these 13 companies as 40.09%. Schedule 5.6 reinforces our conclusion that the average "generous" equity ratio for our sample of electric and gas utilities is around 40%. The same benchmark common equity ratio was chosen by the Board when it set the equity ratio at 40% for all Ontario electricity distributors.[59]

We call this average equity ratio "generous" because it represents the result of a regulatory process in which decisions by regulatory bodies take as input the views of opposing parties that are each representing its own interest. We already showed how the regulatory process may be regarded as generous as it protects utilities from losses and typically results in the regulated companies earning an ROE in excess of the allowed return. Focusing the discussion of generosity on the common equity ratio leads to a similar conclusion. Regulated utilities have little incentive to optimize the use of debt in their capital structures. Having a capital structure with insufficient debt increases the weighted cost of capital because equity is the most expensive form of financing. In the case of regulated utilities, this "extra" cost associated with insufficient debt may be recovered through the process of regulation. If the company can persuade its regulator to approve this unwarranted extra equity, there is no cost to the company from a higher cost of capital. If this occurs, then the regulated company has unused debt capacity which can be a benefit to the parent holding company. The assets of the regulated utility can then serve as collateral to increase the borrowing power of the unregulated part of the holding

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[59] Ontario Energy Board. *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*. December 20, 2006. page 5.

company, thereby adding value for the shareholders. If this occurs, the shareholders gain unfairly at the expense of the customers of the regulated utility who have to pay higher rates to "compensate" the regulated utility for the cost of carrying unwarranted extra equity.

Our final benchmark is derived by focusing on one company from Schedule 5.5: ATCO Pipelines. We select ATCO Pipelines because it represents an example of a utility with greater business risk than a relevant set of comparison companies drawn from different segments of the utility industry in Alberta – the eleven utilities included in the AEUB's Generic Decision 2004-052 and the fifteen in the AUC's Generic Decision 2009-216. In the 2009 hearing, we recommended a common equity ratio for ATCO Pipelines of 42% on a standalone basis independent of the merger with NGTL. The Board awarded 45%. Based on these numbers and recalling our earlier discussion of "generosity" in past decisions, we regard 42% to 45% as an appropriate range for a higher risk utility.

We summarize our discussion of utility industry benchmark equity ratios as falling into a range of 40% to 45%. We form three estimates of the appropriate equity ratio for a utility. The first is 40.46% (Schedule 5.3) and represents the average of actual equity ratios for eight traded utility companies. The second estimate is the average equity ratio allowed 13 regulated entities within these companies by their regulatory boards of 40.09% (Schedule 5.6) combined with the Board's award of 40% for Ontario electric distributors. The third estimate is the range from our recommendation to the equity thickness allowed by the AUC in 2009 for ATCO Pipelines, a high-risk utility, of 42 to 45%. These benchmark equity ratios all fall in a range of 40% to 45%.

5.6.2 Relating the benchmarks to OPG Hydro

In order to use benchmarks to set a recommended capital structure for OPG's two types of assets, it is necessary to draw on our earlier updated business risk analysis. Our analysis of the business risk faced by OPG Hydro assesses this risk as low to moderate –

higher than that of a distribution utility and somewhat above the business risk of an integrated electric utility. This suggests that a fair common equity ratio for OPG Hydro should be at 40%, at the middle of our generous range.

To explore the reasonableness of this conclusion, we reconsider our four benchmarks in turn. Our first benchmark, the average of actual equity ratios for 8 traded utilities is 40.46%. These companies are transmission, distribution or integrated utilities. However, because this measure also includes capital for unregulated activities, which tend to be riskier than regulated businesses, we believe that it exceeds the appropriate level of equity for an average-risk utility. We confirm this view when we look next at our second benchmark of allowed average equity thickness of 40.09% reinforced by our third benchmark of 40% allowed by the Board for electricity distributors. It follows from our view of allowed returns as generous measures of appropriate capital structures that this 40% benchmark should be appropriate for a higher level of business risk. To illustrate, Schedule 5.7 shows that in its Generic Decision, the AUC awarded 39% equity thickness for electricity distribution while we recommended 35%. Given our view that OPG Hydro's level of business risk is above those of the transmission, distribution and integrated utilities in our sample, our second benchmark indicates that a level of equity of no less than 40% is required.

We reinforce this view with our fourth benchmark of 42 to 53% equity recommended and generously allowed by the AUC for a high-risk Alberta utility. Given OPG Hydro's level of business risk, we believe that its target equity ratio should fall toward the low end of this range.

Schedule 5.7 summarizes this discussion and restates our recommendation to set the common equity ratio for OPG Hydro at 40%.

5.6.3 Relating the benchmarks to OPG Nuclear

We take a similar approach in reaching a recommendation for the equity ratio for OPG Nuclear. As we discuss above and summarize in Schedule 5.7, OPG's nuclear assets carry higher levels of operational risk compared to its hydro assets. Further, regulatory risks associated with environmental and safety issues are also elevated compared to that of OPG Hydro. Our analysis rates the business risk of OPG's regulated nuclear assets as moderate (2.6 on our 5 point scale).

Schedule 5.7 shows that this business risk rating for OPG Nuclear exceeds the rating for OPG Hydro (1.8). It also signals that OPG Nuclear bears higher business risk than generic integrated companies (rated 1.5) or generic distribution utilities rated (1.4). The higher business risk of OPG Nuclear should translate into a significant increase in its common equity ratio on the order of 5-10% over that for OPG Hydro producing a recommended equity ratio for OPG Nuclear of 45 to 50%. In the interests of conservatism and to ensure fairness to the shareholder, we stand by our 2008 recommendation of the higher number of 50% for the equity ratio.

As stated earlier, our business risk analysis is updated from our 2008 Evidence to reflect the modest increase resulting from the Board's denial of OPG's request in that hearing for a 25% fixed charge for nuclear assets. In that Evidence, we recommended a modest increase in the equity ratio for OPG Nuclear in the event that the fixed charge request was denied. Such an adjustment is no longer necessary due to the generous equity risk premium awarded by the Board which more than compensates OPG Nuclear for the modest increase in business risk associated with the absence of a fixed charge. In our 2008 Evidence we recommended a utility equity risk premium of 325 basis points for 2008 and 300 basis points for 2009. The Board set the utility equity risk premium at a far higher level of 550 basis points in Decision EB-2009-0084.

5.6.4 Capital structure for OPG's overall rate base

It remains to reconcile our recommendations for OPG Hydro and Nuclear with the capital structure of 47% equity recommended in our 2008 Evidence and mandated by the

Board for the combined entity. Our 2008 Evidence calculated a weighted average of our individual capital structures using the asset breakdown in the *Electricity Restructuring Act* of Ontario of 2004, which set OPG's prices for electricity for 6,606 MW from regulated nuclear generation and 3,332 MW for hydro generation. These two sources total 9,938 MW of which 66.47% is nuclear and 33.53% hydro. Applying these weights to our two separate capital structure recommendations results in an overall rounded recommended equity ratio of 47% for OPG's rate base consistent with the Board's mandate.[60] We summarize our analysis in Schedule 5.7.

5.6.5 Projected coverage ratios for OPG Hydro and Nuclear if they were stand-alone entities

Our recommendations for the capital structures for OPG Hydro and Nuclear flow from our analysis of the business risks of each type of assets and from our review of appropriate industry and regulatory benchmarks. Those benchmarks include bond ratings and we concluded above that a rating of BBB would be sufficient to allow a stand-alone utility to conduct its business properly and to access capital markets. To show that our recommendations of 40% equity for OPG Hydro and 50% for OPG Nuclear are not incompatible with a rating in the A range, we calculate and report the implied Interest and Free Cash Flow (FFO) coverage and Cash Flow to Debt ratios for 2011 and 2012 in Schedules 5.8 using the data supplied by OPG in its application.

To illustrate, we explain our calculations in Schedule 5.8A for OPG Hydro for 2012 in detail. We start with the total rate base of $6,448.1 M financed by capital structure from Table 1 from EB-2010-0008, Exhibit C1, Tab 1, Schedule 1. To obtain the rate base of OPG Hydro of $2,162.1 M for 2012, we multiply by 33.53%, the percentage of

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[60] Updating the weights to reflect the numbers in the current Application leaves the weights unchanged except for minor rounding error. OPG states its total regulated capacities as 6,606 MW nuclear and 3,302 MW hydroelectric for a total of 9,908 MW (EB-2010-0008, Exhibit A1, Tab 4, Schedule 1, page 1). The weights are 66.67% nuclear and 33.33% hydro. The weight of hydro capacity is expected to decrease slightly for the test period to 27.97% (38.4 TWh) vs. 72.03% (98.9 TWh) for nuclear (EB-2010-0008, Exhibit E1, Tab 1, Schedule 1, Page 1 and EB-2010-0008, Exhibit E2, Tab 1, Schedule 1, Page 1). Using these forward-looking weights, the overall capital structure becomes 47.2% equity.

hydro assets discussed above. Applying the capital structure weights gives the principal amounts for Debt and Equity, $1,297.2 M and $864.8M, respectively. We also use OPG's estimate of the cost of total debt for 2012 at 5.58%. We fill in the Board's mandated return on equity for 2010 of 9.85% as a placeholder for 2012. Next, we use these numbers to calculate the allowed costs of capital in dollars for debt and equity for OPG Hydro and Nuclear. Finally, we include an adjustment for taxes on the equity return to reflect the additional pre-tax equity return necessary to pay corporate income taxes. This value is obtained from EB-2010-0008, Exhibit F4, Tab 2, Schedule 1, Table 1. Since interest is paid from pre-tax earnings, no adjustment is necessary to the cost of debt. Our adjustment is similar to the methodology employed by the AUC in calculating coverage ratios in Decision 2009-216.[61] Summing these three amounts, we compute the total allowed dollar cost of capital for the rate base of OPG Hydro as $185.0 M for 2012.

To obtain a projected Interest coverage ratio for the rate base of OPG Hydro, we divide the total allowed cost of capital (allowed earnings on rate base) of $185.0 M by the total cost of debt of $72.4M to obtain a projected Interest coverage ratio for rate base of 2.56 times for 2012.[62] For 2011, we perform a similar set of calculations in Schedule 5.8B. The projected Interest coverage ratio for OPG Hydro for 2011 is 2.61 times, slightly higher than for 2012.

Schedule 5.8C and 5.8D show similar calculations for OPG Nuclear. Following the same approach, the rate base for this division is determined as 67.47% of the total for each year and the capital structure set as 50% debt and 50% equity. The EBIT coverage ratio for OPG Nuclear is 3.39 and 3.22 times for 2012 and 2011 respectively.

In brief, the analysis in Schedule 5.8 shows that our recommended capital structures imply interest coverage ratios in 2012 and 2011 of respectively 2.56 and 2.61 times for OPG Hydro and respectively 3.39 and 3.22 times for OPG Nuclear. We compare these projected coverage ratios against the average actual coverage ratios for traded utilities in

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[61] Alberta Utilities Commission, *Generic Cost of Capital Decision 2009-216*, pages 92- 93.
[62] Schedule 5.8A.

our sample shown as 2.65 times for 2009 in Schedule 5.4. However, we note that the sample includes higher risk unregulated activities as well as goodwill, which could potentially decrease the equity ratio if removed. Comparing this average Interest coverage level to our projection for OPG Hydro first, we conclude that the projected Interest coverage ratio of 2.56 and 2.61 times falls marginally below the middle of the range of observed Interest coverage ratios for our sample of companies with an average bond rating of A (low) or A- that has varying portions of unregulated assets unlike the regulated assets of OPG Hydro. In addition, in light of the Board's and AUC's common position in targeting a rating in the A range, we refine our comparison to the subset of five companies that received a rating of A or A- from at least one bond rating agency: ATCO, Canadian Utilities, Enbridge, Fortis and TransCanada. Of these five companies, three had Interest coverage ratios higher than 2.59 and two had lower levels. Taken in isolation, these two comparisons suggest that there is no reason to believe that OPG Hydro as a stand-alone company with our recommended level of 40% common equity in its capital structure could not achieve a bond rating in the A range. Similarly, for OPG Nuclear, we observe that the projected interest coverage ratios for 2012 and 2011 of respectively 3.39 and 3.22 times far exceeds the sample average and is of the order of magnitude of the A rated companies in our sample, which again includes non-regulated assets. While these higher Interest coverage levels are warranted to some degree by the greater business risk of nuclear operations, our comparisons with levels for publicly traded companies suggests that our recommended equity thickness for OPG Nuclear is conservatively high.

Our conclusion that 40% and 50% equity for Hydro and Nuclear, respectively, are in the A range (A- to A) is consistent with the views of the AUC on its review of Interest (i.e. EBIT) coverage ratios and bond ratings: "The Commission observes from the above table that EBIT coverage ratios of approximately 2.0 to 2.3 appear to be sufficient to obtain credit ratings in the lower A range", and that there is "some indication that the lower end of the EBIT coverage range necessary to maintain a credit rating in the A range is approximately 1.8".[63]

[63] Alberta Utilities Commission, *Generic Cost of Capital Decision 2009-216*, page 92.

Schedules 5.8A to 5.8D extend the ratio analysis to encompass implied Funds From Operations (FFO) coverage and Cash flow to debt ratios again following the practice of the AUC in Decision 2009-216, pages 94 - 95:

> "The Commission has also calculated, and set out in Table 14 below, the ratio of the Funds From Operations (FFO) (net income plus depreciation) divided by debt that would result at different equity ratios assuming an ROE of 8.75 (the 2009 placeholder level) and assuming a range of depreciation rates (as a percentage of invested capital) from 4 percent to 9 percent based on actual depreciations rate results calculated from the 2007 reports on finances and operations. These range from 4.8 percent to 8.5 percent and average 6.0 percent.
>
> Table 14 shows that when the annual depreciation expense as a percentage of invested capital is equal to the utility average of 6 percent, minimum equity ratios in the range of 30 to 36 percent will achieve FFO/Debt percentages of 11.1 to 14.3, which Table 12 shows is associated with credit ratings in the lower A range.
>
> The Commission has calculated, and set out in Table 15, the coverage ratio of the Funds From Operations (net income plus depreciation) divided by interest expense that would result at different equity ratios and depreciation rates assuming an ROE of 8.75 percent (the 2009 placeholder level) and an embedded interest cost of 6.5 percent.
>
> It appears from Table 15 that when the annual depreciation expense as a percentage of investment capital is equal to the utility average of 6 percent, a minimum equity ratio of 33 percent is required to achieve an FFO coverage ratio of at least 3, which Table 7 shows is the minimum FFO coverage associated with credit ratings in the lower A range."

Turning to Schedules 5.8A-5.8D, we see that, compared to the AUC's benchmark of 3 times FFO coverage for credit ratings in the lower A range, the OPG Hydro values are

3.4 and 3.5 times in 2012 and 2011, respectively, and the OPG Nuclear values are 5.5 times and 5.2 times in 2012 and 2011, respectively.

Schedules 5.8A-5.8D also show the Cash flow to debt ratios for both divisions. Compared to the AUC's benchmark of 11.1% to 14.3% for credit ratings in the lower A range, the OPG Hydro values are 11.5% and 11.5% in 2012 and 2011, respectively, and the OPG Nuclear values are 21.6% and 20.9% in 2012 and 2011, respectively.

We qualify this analysis by noting that rating agencies consider other factors in addition to coverage ratios in setting ratings and that bond ratings have shortcomings as a timely measure of risk. Nonetheless, we conclude from our analysis of Interest and FFO coverage and cash flow to debt ratios that, to the extent that such ratios constitute relevant input into bond ratings, the ratios implied by our recommendations are consistent with a bond rating well in the A range.

APPENDIX

BRIEF CURRICULUM VITAE FOR LAWRENCE KRYZANOWSKI

Dr. Lawrence Kryzanowski is currently a Full Professor of Finance and Senior Concordia University Research Chair in Finance (previously Ned Goodman Chair in Investment Finance) at Concordia University. He was until June 2002 the Co-Director of the Concordia-McGill-Xiamen (CMX) Project of the Canada-China University-Industry Partnership Program in Financial Services. He is currently a member of CIRPÉE, a scientific committee member of Institut de Finance Mathématique de Montréal (IFM2), and a member of the scientific advisory board of CEFUP at the University of Porto in Portugal. He is a member of the Board of Governors and its Pension and Benefit Committees at Concordia University, and he was formerly on the Board's Executive Committee. He has been a visiting scholar at the University of British Columbia, a research associate at the University of Rochester, a resident consultant at the Federal Department of Finance, and the first representative of retail investors on the Regulation Advisory Committee (RAC) of Market Regulation Services Inc. (now called IIROC).

Dr. Kryzanowski has extensive experience teaching undergraduates, MBA, MSC and Ph.D. students, and executives for the Institute of Canadian Bankers, Shanghai Banking Institute, CMX, Concordia University, Dalhousie University, McGill University and York University. He has taught "asset allocation and performance measurement" in Concordia's Goodman Institute Program (a private program at the MBA level). This third year course deals with a major component of the level III curriculum of the CFA program. Dr. Kryzanowski has extensive experience in developing or managing the development of instructional textbooks for the Institute of Canadian Bankers (ICB) and the Canadian Securities Institute (CSI), which includes the *Business Solvency Analysis* and *Investment and Portfolio Management* texts for the ICB, and the *Canadian Securities Course* text for the CSI.

Dr. Kryzanowski is an active educator, mentor, consultant and expert witness in financial economics, including investment management, risk pricing and management, and regulation and operations of global financial markets, institutions and participants. He is author or co-author of over 110 refereed journal articles, seven books or monographs, over 195 papers presented at academic conferences and a number of chapter contributions to books of readings/annuals. Dr. Kryzanowski is the first recipient of Prix ACFAS/Caisse de dépôt et placement du Québec, which recognizes an exceptional contribution to research in finance. Dr. Kryzanowski was the inaugural recipient, with co-authors, of the BGI Canada Award and OSFI Award (latter with Dr. Roberts) for excellence in research on capital markets and on regulation of financial institutions, respectively. His 13 other paper awards for co-authored work are from the *Multinational Finance Journal* and various North American academic conferences including the Financial Management Association in 2008. Dr. Kryzanowski is a former Editor of the *Multinational Finance Journal*, co-editor of finance with Dr. Roberts at the *Canadian Journal of Administrative Studies*, and founding chairperson of the Northern Finance Association. Dr. Kryzanowski is currently an Advisory Editor of the *European Journal of Finance*, an Associate Editor of the *International Review of Financial Analysis* and of *Frontier of Finance and Economics*, is member of the Editorial Advisory Boards of *Managerial Finance* and *Studies in Economics and Finance*; and is on the editorial board of *Finance India*.

Dr. Kryzanowski has experience in preparing evidence as an expert witness in utility rate of return applications, stock market insider trading court proceedings, and confidential final offer arbitration hearings for the setting of fair rates for the movement of various products by rail. Together with Dr. Roberts, he prepared a report and briefed counsel on rate of return considerations in the pipeline application in 1997 of Maritimes and Northeast, and prepared evidence on the fair return on equity and the recommended capital structure for the 2001/2002 Distribution Tariff Application (DTA) of ATCO Electric and the 2001/2002 DTA and the 2002 DTA (No. 1250392) of Utilicorp Networks Canada (Alberta) Ltd. before the Alberta Energy and Utilities Board. Together with Dr. Roberts, and on behalf of the Province of Nova Scotia, he provided evidence and testified before the Nova Scotia Utility and Review Board in the matter of Nova Scotia Power Inc. in 2002. Together with Dr. Roberts, and on behalf of the Fédération canadienne de l'entreprise indépendante ("FCEI") / Union des municipalities du Québec ("UMQ") & Option consommateurs ("OC"), he prepared testimony and testified on capital structure and fair return on equity in the matter of Hydro Québec Distribution before the Régie de l'Energie du Québec in 2003. Together with Dr. Roberts, and on behalf of Consumers Group, he prepared testimony and testified in Generic Hearing No. 1271597 before the Alberta Energy and Utilities Board in 2003-2004. Together with Dr. Roberts, and on behalf of the Hydro Communities (Hay River, Yellowknife and Fort Smith), he prepared testimony and testified in NTPC GRA 2006/07 and 2007/08 before the Public Utilities Board of the Northwest Territories in 2007. Together with Dr. Roberts, and on behalf of Pollution Probe, he prepared testimony and testified in EB-2007-0905-OPG-2008-09 Payments before the Ontario Energy Board in 2008. Together with Dr. Roberts, and on behalf of Office of Utilities Consumer Advocate (UCA), he prepared testimony and testified in the Generic proceeding of the Alberta Utilities Commission (AUC), Application No. 1578571, Proceeding ID. 85, 2008-2009.

Dr. Kryzanowski is often sought for his technical ability and advice on various matters in financial economics. He has consulted for the Superintendent of Financial Institutions, Federal Department of Finance, CMHC, CDIC, External Affairs Canada, Canada Investment and Savings, Hydro Quebec, the National Bank, Bombardier, and others.

Dr. Kryzanowski received a B.A. in Economics and Mathematics from the University of Calgary and earned his Ph.D. in Finance at the University of British Columbia.

BRIEF CURRICULUM VITAE FOR GORDON S. ROBERTS

Dr. Gordon S. Roberts is currently CIBC Professor of Financial Services at York University's Schulich School of Business. Prior to joining York University, he was Bank of Montreal Professor of Finance at the School of Business, Dalhousie University. Dr. Roberts has held positions as Visiting Professor and Visiting Scholar at the National Institute for Development Analysis (Bangkok, Thailand), the University of Chile, Tilburg University (the Netherlands), Deakin University (Melbourne, Australia), University of Toronto, University of Arizona, Xiamen University (China) and the University of Zimbabwe.

In addition to teaching undergraduates, MBA and Ph.D. students at these universities, Dr. Roberts has extensive experience in executive teaching for the Kellogg–Schulich Executive MBA Program, the Institute of Canadian Bankers and in the Pension Investment Management School sponsored by the Schulich School jointly with pension consulting firms William Mercer Inc. and Frank Russell.

An active researcher in the areas of corporate finance, bond investments and financial institutions, Dr. Roberts is author or co-author of over forty journal articles and three corporate finance textbooks. In 2000, he shared with Dr. Kryzanowski the OSFI award for excellence in research on the regulation of financial institutions. Dr. Roberts is a former co-editor of finance with Dr. Kryzanowski of the *Canadian Journal of Administrative Studies*. He is a former Associate Editor of the *Journal of Banking and Finance*, and currently serves on the editorial boards of *FINECO* and the *Banking and Finance Law Review*.

Dr. Roberts is experienced in preparing evidence for utility rate of return hearings. From 1995–1997 he submitted prefiled testimony as a Board witness in rate hearings for Consumers' Gas. In 1996, he served as an expert advisor to the Ontario Energy Board in its Diversification Workshop. In 1997, he co-prepared (with Dr. Kryzanowski) a report for the Calgary law firm, MacLeod Dixon, on rate of return considerations in the pipeline application by Maritimes and Northeast. With Dr. Kryzanowski, he filed evidence on three electricity regulatory matters in Alberta in 2001, evidence on regulatory matters before the Alberta Energy and Utilities Board and the Nova Scotia Utility and Review Board in 2002, evidence on regulatory matters dealing with Hydro Quebec Distribution in 2003, evidence in Generic Hearing No. 1271597 before the Alberta Energy and Utilities Board in 2003-2004, evidence in NTPC GRA 2006/07 and 2007/08 before the Public Utilities Board of the Northwest Territories in 2007, and evidence in EB-2007-0905-OPG- 2008-09 Payments before the Ontario Energy Board in 2008.

Often sought for his advice on financial policy, Dr. Roberts has consulted for the Superintendent of Financial Institutions, the federal Department of Finance, Canada Investment and Savings, Canada Mortgage and Housing Corporation, and Canada Deposit Insurance Corporation, among others.

Dr. Roberts received a B.A. in Economics from Oberlin College and earned his Ph.D. at Boston College. He has been listed in the Canadian Who's Who since 1990.

Schedule 2.1

This table summarizes the forecasts of a sample of professionals for the yields and total returns on a number of asset classes, and the Market Equity Risk Premium or MERP implied by the total returns on stock indexes and long government bonds.

Index	Sample size	Percentiles				
		10th	25th	50th (median)	75th	90th
Panel A: Distribution of short-term (2010) return expectations						
30-yr Canada Bonds	30	3.7%	4.0%	4.3%	4.5%	4.9%
S&P/TSX Composite Index	37	4.0%	7.0%	10.0%	12.0%	20.0%
S&P 500 Index	34	2.0%	7.0%	9.0%	14.0%	15.7%
Implied MERP S&P/TSX		0.3%	3.0%	5.7%	7.5%	15.1%
Panel B: Distribution of mid-term (2011-2014) return expectations						
30-yr Canada Bonds	28	4.5%	4.5%	5.0%	5.4%	6.5%
S&P/TSX Composite Index	31	6.0%	7.0%	8.0%	10.0%	10.0%
S&P 500 Index	29	5.0%	7.0%	8.0%	10.0%	12.0%
Implied MERP S&P/TSX		1.5%	2.5%	3.0%	4.6%	3.5%
Panel C: Distribution of long-term (2015-2024) return expectations						
30-yr Canada Bonds	25	4.3%	4.9%	5.3%	5.8%	6.0%
S&P/TSX Composite Index	30	6.0%	7.0%	8.0%	8.0%	9.5%
S&P 500 Index	28	5.0%	7.0%	8.0%	8.8%	10.0%
Implied MERP S&P/TSX		1.7%	2.1%	2.7%	2.2%	3.5%

Source: Towers Watson, *Economic Expectations 2010*, 29th Annual Canadian Survey, page 9.
Survey is described as follows on page 2:

> "The results of Towers Watson's 29th Annual Canadian Survey of Economic Expectations (SEE) are based on the projections of the country's leading business economists, strategists and portfolio managers from more than 50 organizations, such as chartered banks, investment management firms and other corporations. In November 2009, participants were asked to provide forecasts for 24 economic and financial indicators as well as views on pension investment strategies."

Schedule 2.2

This table reports the Market Equity Risk Premiums (MERPs) over bonds reported by Credit Suisse for Canada and the U.S. over the last 10 to 110 years.

Period	Canadian MERP	U.S. MERP
2000-2009	-2.0%	-7.4%
1985-2009	-0.9%	0.7%
1960-2009	1.5%	2.3%
1900-2009	3.7%	4.2%

Source: Credit Suisse, *Credit Suisse Global Investment Returns Yearbook 2010* (Research Institute, February 2010). The MERPs for Canada are found in Figure 2, page 30, and those for the U.S. in Figure 2, page 46. The underlying data are available through Morningstar Inc.

Schedule 3.1

The criteria and rating scale used by BCG when adjusting the firm-level cost of capital to obtain a divisional cost of capital.

Criteria	Values				
	1 or low risk	2	3	4	5 or high risk
Control	Low external influence on return				High external influence on return
Market	Stable, without cycles				Dynamic, cyclical
Competitors	Few, constant market shares				A lot, variable market shares
Products/concepts	Long life cycle, no substitutes				Short life cycle, substitutes
Barriers to entry	High				Low
Cost structure	Low fixed cost				High fixed cost

Schedule 3.2

The criteria and rating scale used by Fuqua Industries when adjusting its firm-level cost of capital to obtain divisional costs of capital.

Criteria	Values				
	1 or low risk	2	3	4	5 or high risk
Customer base dispersion	Many small				A few big
Operational flexibility	High				Low
Loss of asset value	Low				High
Cyclical business	Non-cyclical				Cyclical
Seasonal business	Non-seasonal				Seasonal
Government involvement	Low				High
Changes in technology	Scarce				Often
Market position	Good				Bad
Management	Highly qualified				Little experience
Brand distinction	High				Low
Unionisation	Low				High
Environmental impact	Low				High
Availability of resources	High				Low
Backlogs	High				Low

Schedule 3.3

Proportion of electricity that is generated by various fuel inputs (or of generating capacity) for various countries is presented in this table. The data source is http://www.world-nuclear.org. "Fossil fuel" is represented by the merger of the "Gas" and "Coal" cells in the table.

	Nuclear	Hydro	Gas	Coal	Geothermal	Wind	Other	Year
Australia		7%	12%	80%			1%	2006
Denmark			18	51		18	13%	2007
Finland	27.8	15.5						2009
France	>75%							2009
Germany	≈25%?		12	≈50		6		2007
New Zealand	0	54	27	7	8	2	2.0	2007
*Sweden	42	46.9				1.4	9.7	2008
*Switzerland	43							2007
United Kingdom	19		36	38				2006
USA	20	6	22	49				2008

[Denmark]: Parliamentary resolution exists against building nuclear power plants. Power imported from Sweden (half nuclear & half hydro) and Germany (largely brown coal & nuclear). Has amongst highest electricity prices in world.
[Finland]: Four nuclear reactors provide nearly 30% of its electricity. Fifth reactor is under construction with two more planned. Much of the consumed electricity is either imported (15.3% net in 2009) or generated from imported fuels (mostly coal and some gas). Coal is imported from Russia and Poland, all gas comes from Russia, and 14% of 2009 electricity was from Russia. Two reactors owned by TVO (27% owned by Fortum; supplies generated electricity to shareholders at cost) and two by Fortum Corporation, a public listed energy company which is 51% owned by the Finnish government.
[France]: France derives over 75% of its electricity from nuclear energy due to a longstanding policy based on energy security. France is the world's largest net exporter of electricity to Belgium, Germany, Italy, Spain, Switzerland and the U.K. due to its very low cost of generation. France has 59 nuclear reactors operated by Electricite de France (EdF), which is world's largest utility. EdF has two subsidiaries in regulated sector (RTE EdF Transport, and ERdF, comprising the deregulated activities (mainly Generation and Supply), network activities (Distribution and Transmission) and island activities). EDF had a debt ratio [i.e. net financial debt / (net financial debt + equity including minority interests)] of 49.5% and 56.5% in 2008 and 2009, respectively, and a ratio of FFO to EBITDA of 1.7 and 2.4 in 2008 and 2009, respectively. As of December 31, 2009, it long-term debt ratings were: A+, stable outlook, S&P and Fitch; and Aa3, stable outlook, Moody's. [Management Report EdF 2009 Financial Report, page 178. Available at: http://www.edf.com/html/RA2009/uk/pdf/EDF_RFI09_full_va.pdf]. The French government partially floated shares of the company on Paris Bourse in November 2005, although it retains ≈ 85% ownership as of the end of 2008.
[Germany]: Germany obtains one quarter of its electricity from nuclear energy from 17 operating nuclear power reactors that represent 20.6% of installed capacity. The new 2009 government in 2009 put the phase-out of nuclear energy on hold. Germany is one of the biggest importers of gas, coal and oil worldwide. Construction and operation licensing responsibility of all nuclear facilities is shared between the federal and Länder governments (essential veto power to both). Pursuant to the Energy Law of 2005, electricity rate regulation was abandoned on July 1, 2007 (E.ON AG, Form 20-F, US SEC, page 103. Available at: http://www.eon.com/de/downloads/eon_form20f_2005.pdf).
[New Zealand]: One of the few developed countries not using electricity (indigenous or imported) from nuclear energy. 1.8% of other is from biomass. Growth in demand since 1990 has been mostly met by gas-fired plants. State-owned Meridian Energy, which is the largest generator in New Zealand, accounting for 27% of production in 2008. Contact Energy is the second largest generator in New Zealand and in 2008 accounted for 24% of the country's electricity generation. The company was split from the state-owned Electricity Corporation of New Zealand (ECNZ) in 1996 and is 51% owned by Australian company Origin Energy. State-owned Genesis Energy is the third largest generating company in New Zealand (after Meridian Energy and Contact Energy) supplying about 20% of the country's electricity.

[Sweden]: Parliament voted in June 2010 to repeal the phase out of nuclear power. Has 10 operating nuclear power reactors. The 9.7% under other is fossil fuel. Unlike retail prices, transmission and distribution of electricity are subject to regulation as they are considered to be natural monopolies (E.ON AG, Form 20-F, US SEC, page 103. Available at: http://www.eon.com/de/downloads/eon_form20f_2005.pdf). Sweden deregulated its electricity market on January 1, 1996. With deregulation in 1996, Sweden together with Norway formed the wholesale market Nord Pool, which now also includes Denmark and Finland. Nord Pool sets the price of electricity every hour, based on supply and demand bids.

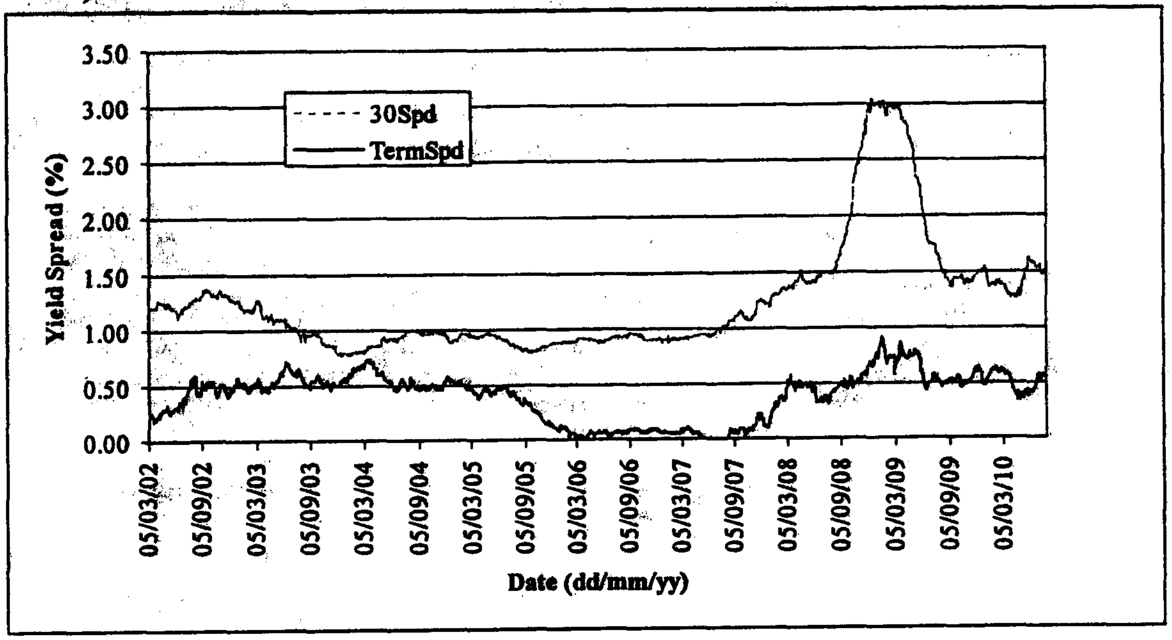
[Switzerland]: 2007 electricity production was mostly from nuclear and hydro, with imports from France and Germany and exports to Italy. Has 5 nuclear reactors generating over 40% of its electricity. In 2009 ATEL (utility consortium) merged with EOS to form Alpiq Holding SA, the country's largest power utility. Early in 2009 EdF increased its stake in Alpiq to 25%. One third of Alpiq's electricity is nuclear. Does not appear to have traditional rate regulation.

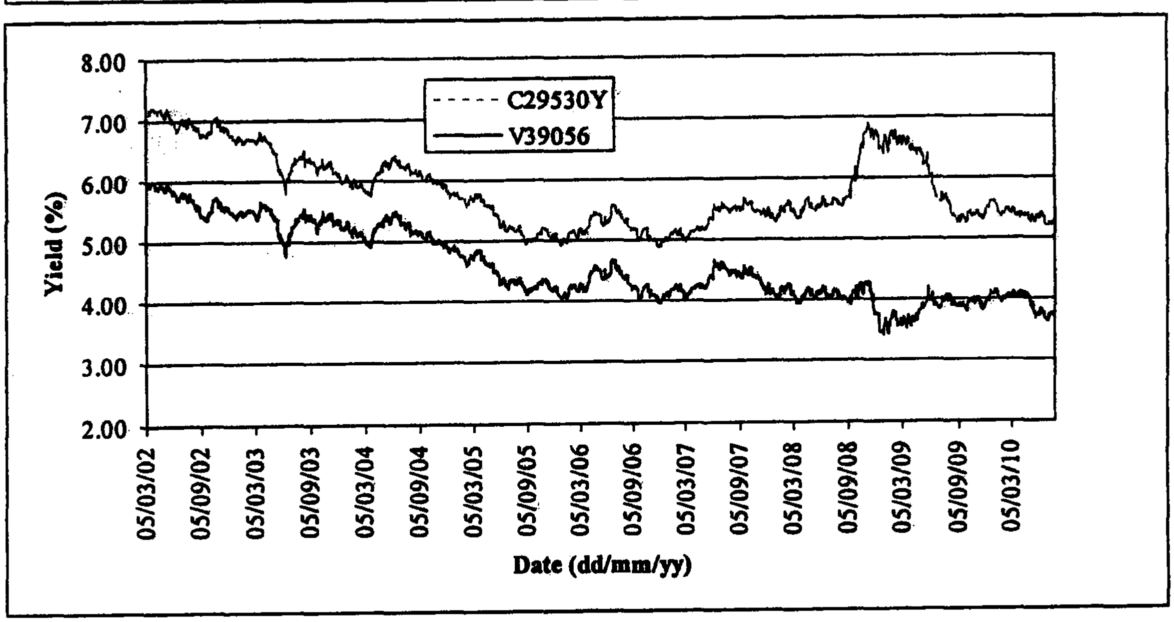
[United Kingdom]: The UK has 19 reactors generating up to 20% of its electricity and all but one of these will be retired by 2023. The first of some 16 new-generation plants are expected on line about 2017. Due to problems with some old plants, nuclear dropped to 15% in 2007 and 13.5% in 2008. About 3% of domestic demand is from imports of French nuclear power. Thus, overall nuclear in UK consumption is normally about 22%.

[USA]: World's largest producer of nuclear power, accounting for more than 30% of worldwide nuclear electricity generation. The country's 104 nuclear reactors in 31 states account for over 20% of total electrical output. Following a 30-year period with few new reactors being built, 4-6 new units are expected by 2018. The first of those resulting from 16 licence applications to build 24 new nuclear reactors made since mid-2007 (changed government policy). The $32 billion merger of Unicom and PECO in 2000 to form Exelon created the largest nuclear power producer in the USA, and the third largest in the world. Exelon has 10 operating nuclear plants with 17 reactors that generated 20% of U.S. nuclear production in 2007. Since 1999, there have been many purchases of existing nuclear power plants.

Schedule 4.1

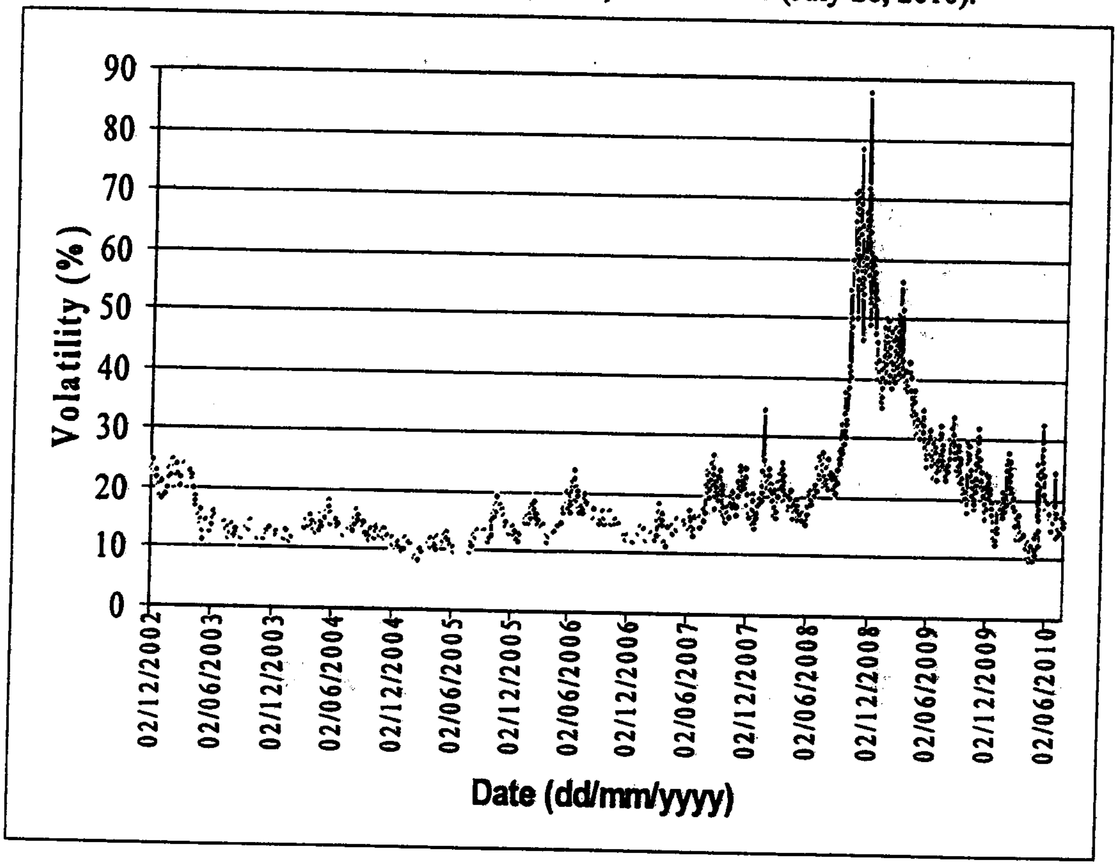
The top figure plots the yield spread (30Spd) between two series, 30-year A-rated Canadian utility bonds (Bloomberg Series C29530Y) and the 30-year benchmark Government of Canada bond (Cansim V39056), and the term spread (TermSpd) between 30- and 10-year Canada's (i.e. Cansim V39056 minus Cansim V39055). The bottom figure plots the yield on 30-year A-rated Canadian utility bonds (Bloomberg Series C29530Y) and the 30-year benchmark Government of Canada bond (Cansim V39056).





Schedule 4.2

This figure plots the expected volatility of the Canadian market as proxied by the S&P/TSX Composite Index. The values are those reported by the Montreal Exchange in its MVX Index on a daily basis from 02122002 (December 2, 2002) to 28072010 (July 28, 2010).



Schedule 5 .1

Electric Utilities Business Risk Rating

Risk	Transmission		Distribution	
Market				
Competition/ demand	Low	1	Low-moderate	2
Credit	Low	1	Low-moderate	2
Operational				
Operating Leverage	Low	1	Moderate	3
Technology	Low	1	Low	1
Capacity	Low	1	Low	1
Asset retirement/construction	Low	1	Low	1
Deferral accounts	Low	1	Low	1
Regulatory				
Primary regulation	Low	1	Low	1
Environmental/safety	Low	1	Low	1
Overall	**Low**	**1**	**Low-moderate**	**1.4**

Schedule 5.1 Continued

Electric Utilities Business Risk Rating

Risk	OPG Hydro		Integrated*
Market			
Competition/demand	Low	1	1.3
Credit	Low	1	1.3
Operational			
Operating Leverage	Moderate	3	2.6
Technology	Low-moderate	2	1.5
Capacity	Moderate	3	2
Asset retirement/construction	Low-moderate	2	1.5
Deferral accounts	Low	1	1
Regulatory			
Primary regulation	Low	1	1
Environmental/safety	Low-moderate	2	1.5
Overall	**Low-moderate**	**1.8**	**1.5**

* Weighted average of transmission 20%, distribution 30% and generation 50% based on Emera 2009 rounded, *Annual Report*, Note 16.

Schedule 5.1 Concluded

Electric Utilities Business Risk Rating

Risk	OPG Nuclear	
Market		
Competition	Low	1
Credit	Low	1
Operational		
Operating Leverage	Moderate-high	4
Technology	Moderate-high	4
Capacity	Moderate	3
Asset retirement/construction	Moderate	3
Deferral accounts	Moderate	3
Regulatory		
Primary regulation	Low	1
Environmental/safety	Moderate	3
Overall	**Moderate**	**2.6**

Schedule 5.2

Senior Unsecured Debt Ratings for the Sample of Canadian Utilities

Corporate Issuer	DBRS Rating	DBRS Debt Rated	Standard & Poor's Rating
ATCO Ltd.	A (low)	Corporate	A
Canadian Utilities	A	Corporate	A
Emera Incorporated Nova Scotia Power	BBB (high) A (low)	MTN	BBB BBB+
Enbridge Gas Distribution Inc. / Enbridge Inc.	A	MTN and Unsecured Debentures	A-
Fortis Inc. Fortis Alberta Fortis BC Newfoundland Power Maritime Electric	BBB (high) A (low) BBB (high) A --	Unsecured Debentures 1st Mortgage Bonds Corporate	A- A- -- -- BBB+
Pacific Northern Gas	BBB (low)	Senior Secured	--
TransAlta Corp.	BBB	Senior Unsecured Debentures	BBB
TransCanada Pipelines	A	Senior Unsecured Debentures	A-
Median	A (low)		A-

Sources: Dominion Bond Rating Service website: www.dbrs.com; Standard & Poor's website: www.standardandpoors.com, August 3, 2010 and Maritime Electric Company Ltd., Testimony of Kathleen McShane, April 2010.

Schedule 5.3

Capital Structure for Utilities 2007-2009 (percentage of long-term capital).

	Long term debt and debentures			Preferred Shares			Common Equity		
	2007	2008	2009	2007	2008	2009	2007	2008	2009
ATCO LTD.	68.25%	66.67%	64.03%	0.00%	0.00%	0.00%	31.75%	33.33%	35.97%
CANADIAN UTILITIES LTD.	49.47%	49.10%	47.43%	10.04%	9.42%	10.77%	40.49%	41.48%	41.79%
EMERA INC.	57.77%	59.74%	62.02%	0.00%	0.00%	0.00%	42.23%	40.26%	37.98%
ENBRIDGE INC.	63.65%	63.73%	64.12%	0.86%	0.69%	0.62%	35.49%	35.59%	35.27%
FORTIS INC.	64.48%	60.53%	61.25%	1.59%	4.04%	3.80%	33.93%	35.43%	34.95%
PACIFIC NORTHERN GAS LTD.	45.78%	45.65%	44.25%	3.14%	3.06%	3.08%	51.07%	51.28%	52.67%
TRANSALTA CORP.	42.59%	45.80%	60.10%	0.00%	0.00%	0.00%	57.41%	54.20%	39.90%
TRANS CANADA PIPELINES LTD.	59.25%	57.50%	53.28%	0.00%	0.00%	1.60%	40.75%	42.50%	45.12%
Average	**56.41%**	**56.09%**	**57.06%**	**1.95%**	**2.15%**	**2.48%**	**41.64%**	**41.76%**	**40.46%**

Source: Annual reports and Financial Post Advisor

Schedule 5.4

Coverage ratios, earned ROEs for selected utilities 2007-2009

Utility	Interest Coverage			Cash Flow to Debt %			ROE %		
	2007	2008	2009	2007	2008	2009	2007	2008	2009
ATCO LTD.	3.31	3.52	3.49	23.71	25.03	23.13	16.69	16.23	14.98
CANADIAN UTILITIES LIMITED	3.25	3.41	3.52	22.46	23.70	21.04	15.96	15.67	16.10
EMERA INCORPORATED	2.54	2.24	2.29	16.85	8.76	10.57	10.93	9.92	11.52
ENBRIDGE INC.	2.37	3.69	3.36	13.19	10.50	14.21	14.53	22.69	22.82
FORTIS INC.	1.78	1.86	1.85	6.37	11.33	10.22	9.96	8.68	8.40
PACIFIC NORTHERN GAS LIMITED	1.75	2.02	2.56	-3.12	21.04	24.46	5.01	6.79	7.32
TRANSALTA CORPORATION	3.17	2.68	2.06	33.75	36.97	13.06	13.07	9.77	6.66
TRANS CANADA CORPORATION	2.60	2.76	2.08	18.62	14.10	14.69	13.99	12.70	9.77
Average	2.60	2.77	2.65	16.48	18.93	16.42	12.52	12.81	12.20

Source: Financial Post Advisor.

Schedule 5.5

Allowed vs. Actual Rates of Return on Equity for 2009

Utility	Allowed Return (%)	Actual ROE for Consolidated Company (%)
ATCO LTD.		14.98
ATCO ELECTRIC TRANSMISSION	9.00	
ATCO ELECTRIC DISTRIBUTION	9.00	
ATCO GAS	9.00	
ATCO PIPELINES	9.00	
CANADIAN UTILITIES LIMITED		
EMERA (NOVA SCOTIA POWER)	9.35	11.52
ENBRIDGE GAS DISTRIBUTION	8.39	22.82
FORTIS INC.		8.40
ALBERTA	9.00	
BRITISH COLUMBIA	8.87	
MARITIME ELECTRIC		
NEWFOUNDLAND POWER	8.95	
PACIFIC NORTHERN GAS LIMITED	9.12	7.32
TRANSALTA CORPORATION	--	6.66
TRANS CANADA PIPELINES LTD.	8.57	9.77
Average	**8.95**	**11.64**

Sources: Schedule 5.4, Board decisions, Ms. McShane's Schedule 2, page 1, Evidence in Maritime Electric Hearing, April 2010. TransAlta has no allowed return since this company is not regulated.

Schedule 5.6

Allowed Common Equity Ratios

Utility	Allowed	Decision
ATCO LTD.		
ATCO ELECTRIC		
TRANSMISSION	36.00	EUB 2009-216,
DISTRIBUTION	39.00	
ATCO GAS	39.00	
ATCO PIPELINES	43.00	
CANADIAN UTILITIES LIMITED		
ENBRIDGE GAS DISTRIBUTION	36.00	OEB RP-2002-0158; EB-2006-0034; EB-2007-0615
EMERA (NOVA SCOTIA POWER)	37.50	NSUARB 2006 NSUARB 23, 2008 NSUARB 140
FORTIS INC.		
ALBERTA	41.00	EUB 2009-216
BRITISH COLUMBIA	40.00	G-52-05; G-158-09
MARITIME ELECTRIC	40.50	UE-09-02
NEWFOUNDLAND POWER	44.14	PU43 (2009)
PACIFIC NORTHERN GAS LIMITED	40.00	G-55-07, L-55-08
TRANSALTA CORPORATION	45.00	U99099
TRANS CANADA PIPELINES LTD.	40	NEB letter 12-09
Average	40.09	

Source: Board decisions and Ms. McShane's Schedule 2, page 1, Evidence in Maritime Electric Hearing, April 2010 .

Schedule 5.7

Electric Utilities Business Risk Rating and Capital Structures

	Transmission	Distribution	OPG Hydro	Integrated	OPG Nuclear	OPG Regulated
Business risk[a]	L 1	L-M 1.4	L-M 1.8	L-M 1.5	M 2.6	M 2.1
Equity Component Deemed by Regulators						
AUC 2009	35%	39%				
NSUARB 2007				37.5%		
OEB 29006, 2007	40%	40%				47%
Fortis Alberta		37%				
Fortis BC				40%		
Maritime Electric				40.50%		
Newfoundland Power				44.14%[64]		
Recommended by Drs. Kryzanowski And Roberts Prior Evidence	33%[65]	35%[66]		35%[67] 42%[68]		
For OPG			40%		50%	47%[69]

[a]L refers to low business risk; L-M refers to low to medium business risk; and M refers to medium business risk. L 1 refers to low business risk based on a business risk rating of 1 to 5 where 5 is the highest numerically business risk rating.

[64] Integrated company, buys 90% of power from Newfoundland and Labrador Hydro.
[65] Generic hearing, Alberta, 2009.
[66] Generic hearing, Alberta, 2009.
[67] NSPI 2002.
[68] Northwest Territories Power Corporation 2007, included business risk premium for size and isolation.
[69] 6,606 regulated MW nuclear (66.47%), 3,332 MW hydro (33.53%).

Schedule 5.8A

This schedule uses OPG' s projections of EBITDA, Taxes, Capitalization and Costs of Equity and Debt to calculate its Interest Coverage Ratio, its FFO Coverage Ratio and its Cash Flow to Debt Ratio for OPG's Hydro Assets for 2012. 'Interest Coverage Ratio' is calculated by dividing 'Allowed $ return on rate base' or 'EBIT' by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'FFO Coverage Ratio' is 'EBITDA (i.e. Funds From Operations or FFO or EBIT as given by 'Allowed $ return on rate base' plus Depreciation & Amortization) divided by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'Cash Flow to Debt Ratio' is calculated by dividing 'Earnings After Tax' + 'Depreciation & Amortization' by 'Total Debt'.

Capital Structure	Principal	Component (%)	Cost (%)	Cost of Capital ($)
Total debt (% of total)	1,297.23	60.00%	5.58%	72.39
Common equity (% of total)	864.82	40.00%	9.85%	85.18
Adjustment for taxes on equity return[a]				27.40
Rate base financed[b]	2,162.05	100.00%		
Allowed $ return on rate base (EBIT)				184.97
Depreciation & Amortization[c]				63.80
EBITDA				248.77

Interest Coverage Ratio (times)	2.56
FFO Coverage Ratio (times)	3.44
Cash Flow to Debt Ratio (%)	11.48

Notes:
[a] Corporate income tax from EB-2010-0008, Exhibit F4, Tab 2, Schedule 1, Table 1, Filed: 2010-05-26.
[b] Total rate base financed by capital structure of 6448.1 million from EB-2010-0008, Exhibit C1, Tab 1, Schedule 1, Table 1, Filed: 2010-05-26, multiplied by 33.53%.
[c] Depreciation & Amortization of 63.4 million plus 0.4 million from EB-2010-0008, Exhibit B2, Tab 4, Schedule 1, Table 2. Filed: 2010-05-26.

Schedule 5.8B

This schedule uses OPG's projections of EBITDA, Taxes, Capitalization and Costs of Equity and Debt to calculate its Interest Coverage Ratio, its FFO Coverage Ratio and its Cash Flow to Debt Ratio for OPG's Hydro Assets for 2011. 'Interest Coverage Ratio' is calculated by dividing 'Allowed $ return on rate base' or 'EBIT' by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'FFO Coverage Ratio' is 'EBITDA (i.e. Funds From Operations or FFO or EBIT as given by 'Allowed $ return on rate base' plus Depreciation & Amortization) divided by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'Cash Flow to Debt Ratio' is calculated by dividing 'Earnings After Tax' + 'Depreciation & Amortization' by 'Total Debt'.

Capital Structure	Principal	Component (%)	Cost (%)	Cost of Capital ($)
Total debt (% of total)	1,271.74	60.00%	5.58%	70.96
Common equity (% of total)	847.83	40.00%	9.85%	83.51
Adjustment for taxes on equity return[a]				30.6
Rate base financed[b]	2,119.57	100.00%		
Allowed $ return on rate base (EBIT)				185.07
Depreciation & Amortization[d]				63.20
EBITDA				248.27

Interest Coverage Ratio (times)	2.61
FFO Coverage Ratio (times)	3.50
Cash Flow to Debt Ratio (%)	11.54

Notes:

[a] Corporate income tax from EB-2010-0008, Exhibit F4, Tab 2, Schedule 1, Table 1, Filed: 2010-05-26.

[b] Total rate base financed by capital structure of 6321.4 million from EB-2010-0008, Exhibit C1, Tab 1, Schedule 1, Table 2, Filed: 2010-05-26, multiplied by 33.53%.

[c] Depreciation & Amortization of 62.9 million plus 0.3 million from EB-2010-0008, Exhibit B2, Tab 4, Schedule 1, Table 2. Filed: 2010-05-26.

Schedule 5.9C

This schedule uses OPG' s projections of EBITDA, Taxes, Capitalization and Costs of Equity and Debt to calculate its Interest Coverage Ratio, its FFO Coverage Ratio and its Cash Flow to Debt Ratio for OPG's Nuclear Assets for 2012. 'Interest Coverage Ratio' is calculated by dividing 'Allowed $ return on rate base' or 'EBIT' by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'FFO Coverage Ratio' is 'EBITDA (i.e. Funds From Operations or FFO or EBIT as given by 'Allowed $ return on rate base' plus Depreciation & Amortization) divided by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'Cash Flow to Debt Ratio' is calculated by dividing 'Earnings After Tax' + 'Depreciation & Amortization' by 'Total Debt'.

Capital Structure	Principal	Component (%)	Cost (%)	Cost of Capital ($)
Total debt (% of total)	2,175.27	50.00%	5.58%	121.38
Common equity (% of total)	2,175.27	50.00%	9.85%	214.26
Adjustment for taxes on equity return[a]				75.90
Rate Base financed[b]	4,350.53	100.00%		
Allowed $ return on rate base (EBIT)				411.54
Depreciation & Amortization[d]				255.60
EBITDA				667.14

Interest Coverage Ratio (times)	3.39
FFO Coverage Ratio (times)	5.50
Cash Flow to Debt Ratio (%)	21.6

Notes:
[a] Corporate income tax from EB-2010-0008, Exhibit F4, Tab 2, Schedule 1, Table 3, Filed: 2010-05-26.
[b] Total rate base financed by capital structure of 6448.1 million from EB-2010-0008, Exhibit C1, Tab 1, Schedule 1, Table 1, Filed: 2010-05-26, multiplied by 67.47%.
[c] Depreciation & Amortization of 239.5 million plus 16.1 million from EB-2010-0008, Exhibit B3, Tab 4, Schedule 1, Table 1. Filed: 2010-05-26.

Schedule 5.8D

This schedule uses OPG' s projections of EBITDA, Taxes, Capitalization and Costs of Equity and Debt to calculate its Interest Coverage Ratio, its FFO Coverage Ratio and its Cash Flow to Debt Ratio for OPG's Nuclear Assets for 2011. 'Interest Coverage Ratio' is calculated by dividing 'Allowed $ return on rate base' or 'EBIT' by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'FFO Coverage Ratio' is 'EBITDA (i.e. Funds From Operations or FFO or EBIT as given by 'Allowed $ return on rate base' plus Depreciation & Amortization) divided by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'Cash Flow to Debt Ratio' is calculated by dividing 'Earnings After Tax' + 'Depreciation & Amortization' by 'Total Debt'.

Capital Structure	Principal	Component (%)	Cost (%)	Cost of Capital ($)
Total debt	2,132.52	50.00%	5.58%	118.99
Common equity	2,132.52	50.00%	9.85%	210.05
Adjustment for taxes on equity return[a]				53.9
Rate base financed[b]	4,265.05	100.00%		
Allowed $ return on rate base (EBIT)				382.95
Depreciation & Amortization[d]				234.50
EBITDA				617.45

Interest Coverage Ratio (times)	3.22
FFO Coverage Ratio (times)	5.19
Cash Flow to Debt Ratio (%)	20.85

Notes:

[a] Corporate income tax from EB-2010-0008, Exhibit F4, Tab 2, Schedule 1, Table 3, Filed: 2010-05-26.

[b] Total rate base financed by capital structure of 6321.4 million from EB-2010-0008, Exhibit C1, Tab 1, Schedule 1, Table 2, Filed: 2010-05-26, multiplied by 67.47%.

[c] Depreciation & Amortization of 218.9 million plus 15.6 million from EB-2010-0008, Exhibit B3, Tab 4, Schedule 1, Table 1. Filed: 2010-05-26.

TAB 2

Before the Ontario Energy Board

In the matter of:

EB-2007-0905 - OPG - 2008-09 Payments

Exhibit M
Tab 12

Evidence on Behalf of Pollution Probe

On Capital Structure, Return on Common Equity, Automatic Adjustment Formula

Text, Appendices and Schedules

Prepared Testimony of

Dr. Lawrence Kryzanowski and Dr. Gordon S. Roberts

Concordia University Research Chair in Finance, John Molson School of Business, Concordia University, Montreal; and CIBC Professor of Financial Services, Schulich School of Business, York University, Toronto.

April 2008

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year 2008. Similarly, adding 15 basis points to 4.1% gives 4.25% as the forecast rate for 30-year Canada's for 2009.

2.4.2 Forecasts for the 30-year U.S. Treasury Bond Yield

Our forecast for the 30-year U.S. Treasury bond yield follows the same methodology that we employ for the long-term Canada rate. We obtain consensus mean forecasts for the 10-year U.S. Treasury bond rate from the same issue of *Consensus Forecasts* (published by Consensus Economics) that is used for the Canada forecasts above: 3.7% for the end of June 2008 and 4.1% for the end of March 2009.

Following our practice for Canadian rates discussed earlier, we convert these forecasts for 10-year Treasuries to forecasts for the yield on 30-year Treasuries by adding an estimated average spread. For the U.S. we measure the spread by averaging observed values over the most recent four quarters (Q1 through Q4 2007). For U.S. Treasuries this was 25 basis points based on data from TD Economics. We also examine data for the first quarter of 2008 which show a somewhat higher value. We then add 25 basis points to 3.7% to obtain 3.95% as our forecast for the U.S. 30-year Treasury yield for the end of June 2008. For the end of March 2009, adding 25 basis points to 4.1% gives 4.35% as our forecast for the yield on 30-year U.S. Treasury Bonds.

3. CAPITAL STRUCTURE

3.1 OVERVIEW OF THIS SECTION

We begin with a brief overview of the practical implications of financial theory for our analysis of the appropriate capital structure for OPG. Our main conclusion is that, although no generally accepted formula exists for setting capital structure, the level of equity should increase with the degree of business risk.

To implement this conclusion, we next review the business risks faced by OPG hydro assets (OPG Hydro) and nuclear assets (OPG Nuclear) separately. Our review of market, operational and regulatory risks leads to the conclusion that OPG's regulated hydro business carries low to moderate risk (1.8 on a scale of 5 where 1 is the lowest risk and 5 the highest). In contrast, OPG's regulated nuclear generation has a higher level of business risk which we assess as approaching moderate (2.3 on our 5-point scale).

In order to gain perspective on these measures of business risk, it is useful to compare them against the risks of generic electricity transmission and distribution businesses as well as those of integrated electric utilities. This will allow us to benchmark our recommendations for OPG against capital structures allowed by this Board and by other Canadian regulators for other companies in these categories. Our approach also facilitates comparisons with our own analysis in prior testimony. We assess the average risk for transmission as low (1 on our 5-point scale). We also study the business risk associated with generic distribution and rate it as low to moderate (1.4 on our scale). Based on these inputs, we assess the business risk of an integrated company by taking an asset-weighted average of the risks of OPG hydro, generic transmission and generic distribution. Our analysis sets the business risk of an integrated electricity company at 1.5 on our scale or low to moderate.

We then turn to examining relevant financial data for a sample of eight Canadian gas and electric utilities and pipelines that have publicly traded common shares. We require the included companies to be publicly traded to ensure consistency between our samples here and in later sections where we present our evidence on the fair rate of return. We analyze bond ratings, capital structures, interest coverage ratios and returns on equity for our sample companies.

Drawing on the basic principle that the level of equity in the deemed capital structure of a utility should reflect its business risk and combining our risk assessments, we conclude that being considerably riskier than a generic transmission and somewhat riskier than an integrated company or a generic distribution company, OPG hydro should carry a higher level of equity than any of these three comparators. We assign 40% as the appropriate equity ratio for OPG's hydro assets. Following similar logic, we set 50% as the fair level of equity for OPG's nuclear assets. To achieve a recommendation for OPG's combined regulated assets we take a weighted average of our two recommendations based on regulated MW (megawatts): 6,606 for nuclear (66.47%) and 3,332 MW for hydro (33.53%) to attain an overall recommended capital structure of 47% equity.

3.2 IMPLICATIONS OF FINANCIAL THEORY

Finance theory has several important implications for setting the appropriate level of the equity ratio for a regulated electric utility. First, theory teaches us to be suspicious of attempts to determine an appropriate equity ratio using a formula. Unlike other areas in finance, research on capital structure can offer only qualitative policy advice. To quote a leading, current corporate finance textbook:

"No exact formula is available for evaluating the optimal debt-equity ratio."[10]

While we expect an introductory textbook to contain an element of simplification in order to present material to beginning students, this statement has yet to be superseded by advanced research. We review selected research on capital structure in Appendix 3.A.

This important implication of finance theory has been accepted by Canadian regulators including the Alberta Utilities Commission (formerly the Alberta Energy and Utilities Board). In Decision 2004-052, page 35, it wrote:

"In the Board's view, setting an appropriate equity ratio is a subjective exercise that involves the assessment of several factors and the observation of past experience. The assessment of the level of business risk of the utilities is also a subjective concept. Consequently, the Board considers that there is no single accepted mathematical way to make a determination of equity ratio based on a given level of business risk."

Although it does not offer a formula, finance theory does highlight key considerations in determining capital structure. In the same textbook we find the following:

"How should companies establish target debt-equity ratios? While there is no mathematical formula for establishing a target ratio, we present three important factors affecting this ratio:[11]

- Taxes. As pointed out earlier, firms can only deduct interest for tax purposes to the extent of their profits before interest. Thus, highly

[10] S.A. Ross, R.W. Westerfield, J. F. Jaffe and G.S. Roberts, *Corporate Finance*, Fifth Canadian Edition, Toronto, McGraw-Hill Ryerson, 2008, p. 500.
[11] S.A. Ross, R.W. Westerfield, J. F. Jaffe and G.S. Roberts, *Corporate Finance*, Fifth Canadian Edition, Toronto, McGraw-Hill Ryerson, 2008, p. 502.

profitable firms are more likely to have larger target ratios than less profitable firms.

- Types of assets. Financial distress is costly, with or without formal bankruptcy proceedings. The costs of financial distress depend on the types of assets that the firm has. For example, if a firm has a large investment in land, buildings, and other tangible assets, it will have smaller costs of financial distress than a firm with a large investment in research and development. Research and development typically has less resale value than land; thus, most of its value disappears in financial distress. Therefore, firms, with large investments in tangible assets are likely to have higher target debt-equity ratios than firms with large investments in research and development.
- Uncertainty of operating income. Firms with uncertain operating income have a high probability of experiencing financial distress, even without debt. Thus, these firms must finance mostly with equity. For example, pharmaceutical firms have uncertain operating income because no one can predict whether today's research will generate new drugs. Consequently, these firms issue little debt. By contrast, the operating income of utilities generally has little uncertainty. <u>Relative to other industries, utilities use a great deal of debt</u> [emphasis added]."

Taken together, these three factors are central to establishing the appropriate amount of debt for a utility. If we set aside the second and third factors for a moment, the first factor tells us that a company should use a large proportion of debt financing to reduce its cost of capital. Simply stated, factors 2 and 3 determine the level of business risk which restrains the company's use of debt in order to reduce the cost of financial distress and the probability that it will occur due to low operating income. Turning from speaking in general about any company to focusing on a regulated electric utility, we believe that factors 2 and 3 are largely mitigated by the special features of this industry.

For an electric utility, the costs of financial distress (factor 2) are reduced because its assets make excellent collateral. Further, the regulation process virtually ensures that the company will recover its debt payments and other costs. Further, regulation allows the company to go back to its regulator to apply for relief in the unlikely event that it does not earn its fair rate of return in a given year, and especially if its ability to service its debt were in jeopardy. Additionally, in the extreme event that an electric utility became insolvent, it is highly likely that the regulator (and other governmental bodies) would work with the company to find new investors or a merger partner so that service (and thus, asset usage) would not be interrupted. This is what occurred with the bankruptcy of Pacific Gas and Electric Company in California.[12] As a result, the cost of financial distress is far lower than for a nonregulated firm.

The third factor is the probability of financial distress. As stated in the quotation, this probability is low for utilities because operating income has low variability, which is further diminished if the utilities make extensive use of deferral accounts. In conclusion, we come back to the beginning of our answer to this question. If we set aside factors 2 and 3 (the costs of financial distress and the probability of financial distress), the theory suggests that a company should use a high proportion of debt. Our comments on factors 2 and 3 explain why it makes sense to expect them to carry less importance in practice for this industry. With the focus then on the first factor, taxes, we would expect regulated electric utilities to be among the most highly leveraged industries.

We now turn from electric utilities as an industry to examine the business risk of OPG both on its own and relative to that of other sectors of the industry.

[12] K. Gaudette, Bankrupt Pacific Gas and Electric hopes to avoid state laws, Associated Press, *The Nando Times*, January 25, 2002, www.nando.net/business/story/228567p-2199342c.html.

3.3 BUSINESS RISK OF ONTARIO POWER GENERATION

3.3.1 Framework for Analysis

Our assessment of business risk focuses on uncertainty of operating income introduced earlier in our overview of important factors in the determination of capital structure. Factors that increase costs to a utility such as higher fuel prices do not necessarily translate directly into increased business risk. Management can prevent these factors from increasing the uncertainty of operating income in several ways. First, it can forecast their impacts and build them into proposed pricing. In a fair regulatory environment, such costs will be allowed and passed on to customers. Second, management can engage in risk mitigation to control the impact of such factors on operating income. Third, risk can be mitigated by use of deferral accounts. Business risk is only increased to the extent that these three approaches to control risk only work incompletely.

Our analysis of business risk begins with an examination of the risks of hydroelectric and nuclear generation for OPG. Because the two types of generation carry different risks we assess each separately. We introduce each of the three major categories of business risk for utilities: market, operational and regulatory, and discuss each in detail first for the regulated hydro and then for the nuclear operations of OPG. Our discussion presents a detailed breakdown of the components of business risk within each category and a numerical ranking of each on a scale of low (1), moderate (3) or high (5). We create a summary table, Schedule 3.6, displaying the rankings of each of 9 individual risks covering our three categories. Our conclusion is that the regulated hydro generation activities of OPG carry a low to moderate level of business risk (1.8 on our 5 point scale with a score of 1 representing low risk and 5 the highest risk for a utility). The regulated nuclear operations are rated as approaching moderate risk (2.3 on our 5-point scale).

To provide perspective on our business risk rankings, we next use our framework to measure the business risks of other sectors of the utilities industry and explain why we agree with the commonly held view that transmission (wires) carries the lowest business risk followed by distribution and then by generation with the highest business risk. We assess the business risk of transmission utilities as low (score of 1 out of 5) and distribution utilities as somewhat higher at low to moderate (1.4). These assessments form the basis for our capital structure recommendations for OPG Hydro and OPG Nuclear below. The analysis of business risks in the transmission and distribution sectors provides the basis for comparisons with deemed capital structures in those sectors.

3.3.2 Business Risk of OPG's Hydroelectric Generating Assets

3.3.2.1 Market Risk

Market risk is the risk that a hydro generator will not be able to meet its target sales due to weak markets, to competition or to other related factors. OPG is the market leader in Ontario accounting for 71% of the electricity sold in 2007.[13] DBRS expects that the company will retain this position for the near future out to 2014. The Ontario economy is facing slowing growth in the short-run particularly in the manufacturing sector as discussed in Section 2 but residential growth remains steady. The province has experienced long-term growth of around 1% annually in electricity consumption over the period 1998-2007. In the most recent years, growth has displayed a flattening tendency with rates of -3.8% and 0.7% for 2006 and 2007, respectively.[14] Because OPG is a base-load, low marginal cost generator it is not expected to experience a significant level of demand or dispatch risk. Competitive cost structure and transmission limitations protect

[13] Our discussion draws on Ontario Power Generation, Corporate Credit Rating, Standard & Poor's, December 9, 2005 and DBRS Rating Reports, August 3, 2006 and November 30, 2007.
[14] 18 Month Outlook: An Assessment of the Reliability of the Ontario Electricity System From April 2008 to September 2009, Independent Electricity System Operator (IESO), March 12, 2008, Hwww.ieso.caH

OPG from competitive supply threats from Quebec and Manitoba. We assign a rating of low (1 out of 5) for competition / demand risk as shown in Schedule 3.1.

Our view of competition/demand risk agrees with that of Ms. McShane who states: "Nevertheless, dispatch risk for the regulated assets is currently relatively low" (Exhibit C2, Tab 1, Schedule 1, page 59).

A related component of market risk is the credit risk that may arise if a utility's customers default on their payments. This element of market risk is also low (1 out of 5) for OPG because it does not sell directly to ultimate power users.

With competition/demand risk and customer credit risk both rated low, we conclude that market risk is low (1 out of 5) for OPG's hydro generation business.

3.3.2.2 Operational Risk

Operational risk represents the risk that OPG will not meet production and profitability targets. We identify four elements of operational risk and discuss them in turn. We also discuss how deferral accounts serve to mitigate the various elements of operational risk. The first component of operational risk is operating leverage which arises when operations such as hydro generation are characterized by a high level of fixed costs which make operating cash flow more sensitive to changes in production. We assess operating leverage as moderate (3 out of 5) in Schedule 3.1. Related to operating leverage, advanced technology also impacts fixed costs as well as making production more sensitive to technical breakdowns. We assign a risk rating of low to moderate (2 out of 5) to technology risk.

Capacity risk relates to forced outages due to unanticipated breakdowns or prolonged maintenance. Hydroelectric generation is typically subject to a low rate of forced outages. Capability factors measure reliability as the ratio of available energy generation to reference energy generation defined as production under full power. Available energy generation may fall below reference levels due to "limitations within control of plant management, i.e., plant equipment and personnel performance, and work control" according to the International Atomic Energy Agency.[15] In a regulatory perspective, such a shortfall does not constitute a risk for which a utility should be compensated. OPG continues its traditional record of high capability factors for its hydro units.

Further, hydro generating units are not subject to the risk of increasing fuel costs as are fossil fuel and nuclear units. Nor do they fall prey to significantly increased risks of environmental compliance. However, availability of water does create a production risk as lower water levels could reduce output and create unrecovered costs. Historically, water availability has not been a problem for OPG due to its diversification of regulated hydro assets on two river systems, the St. Lawrence and Niagara Rivers.[16]

Further, OPG currently has a deferral account (Water Conditions Deferral Account) which allows the company to collect cost recovery in years with lower water levels and to replenish the account when water levels are above average. The company has applied to the Board to continue this account. Assuming that the Board grants this continuation, the risk to OPG from water variability is low.

Considering all the elements of capacity risk produces a rating of moderate (3 out of 5). The presence of a water deferral account mitigates capacity risk and leads to a rating of low risk (1 out of 5) under deferral accounts.

A further aspect of operational risk arises from costs that can arise from the obligatory retirement of assets and construction of new generation. For its hydro generation, environmental issues related to asset retirement are not a major

[15] Hwww.iaea.orgH
[16] Corporate Credit Rating, Standard & Poor's, December 9, 2005

concern as they are for coal burning and nuclear units. Hydro generators do face risks with regard to capital expenditures. However, the recovery of fixed capital costs such as depreciation is included in the allowed rate. DBRS believes that these risks will be mitigated by financial structuring:

> "It is expected that OPG will not undertake any major capital projects without having its financing and cost-recovery mechanism in place, thus minimizing the financial risks. It is also expected that OPG will turn to the OEFC for project-style financing in the capital markets to fund these projects. Although OPG may be able to reduce its risks through design-build contracts, some residual risk will remain on significant capital expenditures".[17]

In brief, our assessment of risks associated with asset retirement and construction leads us to conclude that this risk is low to moderate for OPG Hydro.

3.3.2.3 Regulatory Risk

Regulatory risk can arise when costs are disallowed, allowed returns do not fit market expectations or rate design (including allowed capital structures) varies from what is fair and reasonable in view of business risks. Alternatively, regulation can mitigate risks through the introduction of deferral accounts and by allowing generous allowed returns and capital structures as discussed in other parts of this evidence.

We believe that regulation by the Board plays the second, positive role for OPG and assess the regulatory risk as low for a number of reasons. First, as discussed earlier, deferral and variance accounts allowed by the Board in the past and likely to be continued reduce operational risk. Second, as also explained above, we expect that the Board will approve structures that will mitigate the risk of future construction. Third, it is our understanding that the

[17] Ontario Power Generation Inc., DBRS Rating Report, November 30, 2007, page 4.

Board regulates in a fair manner. It follows that it is logically contradictory for the Board to recognize possible future political interference as a risk for which the company should be compensated.

Ms. McShane's evidence offers two, apparently conflicting, views of the regulatory risk faced by OPG. On page 63, she states: "On balance, I view the regulatory risk for OPG as higher than that of the typical regulated utility in Canada and in Ontario". Page 60 contains a contrasting view implying that regulatory risk is low:

> "For purposes of the business risk assessment, I proceed on the assumption that OPG will be treated no differently from any other utility subject to the Board's jurisdiction: OPG will be provided a reasonable opportunity to recover its prudently incurred costs and earn a return that reasonably reflects the risks to which it is exposed."

Pollution Probe Information Request #49 asked Ms. McShane to reconcile these two statements. Her reply was:[18]

> "The first statement [page 60] simply means that the Board would seek to apply the same standards and principles to OPG as to other utilities under its jurisdiction. The second statement needs to be read in conjunction with the paragraph that follows:
>
> 'As the Board suggested in its November 20, 2006 report, the application of cost of service regulation to generation is a relatively unique phenomenon, with no track record upon which to gauge the outcome. The uncertainty of the "end state" is amplified by the fact that OPG will be regulated in a market

[18] Ms. McShane's Response to Pollution Probe Interrogatory #49, EB-2007-0905, Exhibit L, Tab 12, Schedule 49, page 1 of 1.

environment which is a hybrid of regulation and competition, which creates additional pressure on regulated rates in a period of potentially significant cost increases (e.g., decommissioning costs, other post-retirement benefit expenses).' "

Our reading of Ms. McShane's response is that the Board may seek to regulate fairly but, due to the novelty of its task, be unable to achieve that goal. This argument lacks any logical basis. Therefore, for reasons explained above, we agree with her second assessment of regulatory risk associated with OPG's primary regulator as low (1 out of 5).

Regulatory risk may also arise due to unanticipated shifts in environmental or safety regulations or in their enforcement. Because hydro generation does not involve the burning of fossil fuels or the potential dangers of nuclear generation, we rate this element of risk as low to moderate (2 out of 5).

3.3.2.4 Summary on Business Risk for OPG's Hydroelectric Assets

Our review assesses nine dimensions falling within the three main areas of business risk, market, operational and regulatory and the ratings presented above are summarized in Schedule 3.1 in the column marked OPG Hydro. As the Schedule shows, the average-risk rating is 1.8 producing a low to moderate level of business risk for OPG's hydro assets.

3.3.3 Business Risk of OPG's Nuclear Generating Assets

3.3.3.1 Market Risk

Market risk is the same for nuclear as for hydro generation. Therefore, we assess both competition and customer credit risks as low for the reasons explained earlier.

3.3.3.2 Operational Risk

Nuclear technology is more advanced and characterized by a greater degree of fixed costs (operating leverage) and higher technology risk. We rate both as moderate to high (4 out 5). Mitigating risk deriving from operating leverage is the proposed fixed charge covering 25% of the projected nuclear revenue requirement. Nuclear generation is also subject to more intense environmental and safety regulations that create the potential for lengthy unplanned outages. In the case of OPG the greater risk of nuclear generation is magnified by issues related to unplanned maintenance and inspection outages.

As explained above, to the extent that such production shortfalls are due to factors under the control of management, they do not constitute a risk for which a company should be compensated. By comparing unit capability factors supplied by OPG against the industry benchmark of 91% provided by DBRS, we may assess management performance. OPG provided such data on unit capability factors in its response to Pollution Probe Interrogatory #5 (bolding added).[19] Specifically:

> "The table below provides unit capability factor percentages for each of OPG's nuclear units for the period 2005 – 2007. The data are provided as 'Unit Capability Factor' consistent with the manner in which OPG has represented unit output in its evidence (please see definition provided at Ex. E2-T1-S1, page 23). 'Annual capacity utilization rates' is not a term OPG uses to track generation output.
>
> OPG declines to provide historical information prior to 2005 for the reasons given in L-12-6."

[19] OPG's Response to Pollution Probe Interrogatory #5, EB-2007-0905, Exhibit L, Tab 12, Schedule 5, page 1 of 1.

ONTARIO POWER GENERATION NUCLEAR
Unit Capability Factor (%)

Unit	2005	2006	2007
Darlington			
Unit 1	**96.1**	83.5	**97.0**
Unit 2	79.2	**98.6**	83.0
Unit 3	**98.7**	72.7	**94.2**
Unit 4	85.8	**97.1**	81.0
Pickering A			
Unit 1	**92.7**	77.3	38.9
Unit 4	66.5	66.3	43.7
Pickering B			
Unit 5	53.3	89.7	57.7
Unit 6	64.3	86.5	71.8
Unit 7	**97.9**	59.2	82.0
Unit 8	**94.5**	64.9	87.3

We have added emphasis by marking in bold each plant year in which the capacity factor equals or exceeds the industry benchmark of 91.0%. This occurred in 9 of 30 plant years, i.e. for 30% of the plant years. For 21 of 30 plant years (70% of the cases) the unit capability factor failed to achieve the benchmark level. These data strongly suggest that production shortfalls attributable to management issues (and not constituting a risk to be recognized in regulation) were a major concern for OPG Nuclear in the period 2005-7.[20]

Unpredicted fuel cost increases represent an added potential capacity risk to nuclear generation. Although the price of uranium has increased dramatically in the past from $15.55U.S. per pound in January 2004 to $73U.S. in February 2008, this increase is not expected to continue as new supply comes into the market.[21] Further, this price increase was moderated somewhat by the rise in the Canadian dollar. Analysts surveyed by Reuters in December 2007 predicted that

[20] Data for capability factors for these plants going back to inception are available on the website of the International Atomic Energy Agency. They show a similar pattern of low capacity factors.
[21] www.cameco.com

the average mid-range spot price for uranium will go to $106.90U.S. in 2008 and moderate to $91.90U.S. in 2009.[22] Further, it is only the unexpected component of any price increase that is a source of risk and OPG has two lines of defense against fuel cost risk. First, the company engages in fuel price hedging for both fossil and nuclear fuels. According to Standard & Poor's, OPG hedged 100% of estimated fuel needs for 2005 and 93% for 2006.[23] Second, uranium fuel price risk will be covered by the variance account requested in this proceeding. According to Ms. McShane, "OPG is requesting a variance account to record variances between forecast and actual uranium costs. The proposed variance account would cover the preponderance of OPG's fuel price risk".[24]

As we noted earlier, costs of decommissioning assets and disposing of used fuel are higher for nuclear than for hydro generation. For OPG these risks are mitigated by funding of a Used Fuels Fund and a Decommissioning Fund under the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province. Under the ONFA the Province and OPG share the risks associated with the assumed rates of return on these funds. According to DBRS, the decommissioning fund was overfunded as of September 30, 2007.

A final aspect of operational risk derives from the need to build new generation assets. Because the largest proportion of OPG's planned future growth is in nuclear, this risk is higher than for hydro generation. As indicated in our discussion of hydro risks, however, this risk is mitigated through project structuring.

Summarizing our discussion of operational risk in OPG's nuclear assets, the company faces moderate to high levels of both operating leverage and technology risks both rated 4 out of 5. Its moderate (3 out of 5) exposure to

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[22] Anna Stablum, Strong demand to boost spot uranium price in 2008, Reuters, January 22, 2008, Hwww.reuters.comH.
[23] Corporate Credit Rating, Standard & Poor's, December 9, 2005.
[24] McShane's Evidence, EB-2007-0905, Exhibit C2, Tab 1, Schedule 1, page 73.

capacity risk arises from aspects of nuclear generation outside of management control. The stand-alone principle of regulation implies that costs associated with capacity risk arising from substandard reliability or other causes under management control should not be considered in rate making. Further, OPG faces moderate risk associated with decommissioning and construction. Finally, deferral accounts related to fuel costs and funds supporting used fuel and decommissioning costs mitigate the associated risks leading to a low rating (1) for deferral accounts. In addition, this rating reflects the proposed 25% fixed capacity charge which also serves to moderate operating risk.

3.3.3.3 Regulatory Risk

Regulatory risk associated with the primary regulator is subject to the same factors for nuclear as for hydro assets. The difference is that the stakes are higher due to the higher operational risk of nuclear generation. On this point we agree with Standard & Poor's which states:

> "OPG is likely to be the first and only generator to fall under OEB's (Ontario Energy Board's) regulatory oversight. It remains to be seen whether the capital structure and returns allowed by the regulator post 2008 will reflect the much operating risks associated with electricity generation (including hydrology risk and nuclear technology risk) as compared with the low risk profile of distribution and transmission companies" (Corporate Credit Rating, Standard & Poor's, December 9, 2005, page 6).

Nuclear assets are subject to additional regulatory risks relating to environmental and safety regulation under the supervision of the Canadian Nuclear Safety Commission (CNSC). The CNSC regulates Canada's seven nuclear power plants including those of OPG along with other nuclear reactors.[25] Due to the high level of regulation, it is possible that an enhancement to

[25] Hwww.nuclearsafety.gc.caH.

regulations or an unexpectedly strict interpretation by CNSC could cause unforeseen costs or unplanned outages at one of OPG's plants. Such a closure occurred at the Chalk River nuclear research facility operated by Atomic Energy of Canada Ltd. in November 2007. At issue was the classification of a redundant safety system as either an optional safety enhancement or a necessary condition of licensing.[26] Further, future legislation could impose more onerous safety regulations on OPG.

While we recognize that shifts in environmental and safety regulation do pose a risk to OPG in its nuclear operations, we assess this risk as moderate for several reasons. First, the risk is only a possibility and to date has been overshadowed by management issues as the main cause of capacity shortfalls. Second, should the risk from shifts in environmental and safety regulation materialize, it can be mitigated by a deferral account as documented by Ms. McShane:

> "To the extent that nuclear production is adversely impacted by changes in legislation or regulations related to CNSC compliance or compliance with any other applicable laws, OPG is at risk, with the proviso that it retains the right to request a deferral account to recover related costs if they result in a material financial impact" (Exhibit C2, Tab 1, Schedule 1, page 72).

In brief, our review of OPG's regulatory risk in its nuclear generation rates regulatory risk with respect to the Board as low based on our earlier discussion of regulatory risk. Additional regulatory risk arises from possible shifts in environmental and safety regulations regarding nuclear operations but this is mitigated by the minor role currently played by this risk and the company's right to request a deferral account should the risk become material in the future. Overall, we assign a rating of moderate to this second aspect of regulatory risk arising from OPG's nuclear operations.

[26] Peter Calamai, "Medical isotope power struggle", Hwww.thestar.comH , February 25, 2008.

3.3.3.4 Summary of Business Risk of Nuclear Generation

Our review examines the three main areas of business risk (market, operational and regulatory) using nine dimensions. We summarize the ratings presented above in Schedule 3.1 in the column marked OPG Nuclear. As the Schedule shows, the average risk rating is 2.3 approaching a moderate level of business risk for OPG's nuclear assets.

3.4 RELATIVE RISKS OF ELECTRICITY SECTORS

With our business risk analysis of OPG's hydro and nuclear generation complete, we now turn to an examination of the relative business risks of electricity transmission and distribution. Because there are a number of regulated companies in these sectors in Canada, such a comparison provides a useful perspective.

Market competition risk is low for transmission because of its status as a natural monopoly. While electricity distribution also has the characteristics of a monopoly it carries higher market competition risk due to the possibility of customers switching to natural gas or increasing reliance on co-generation. Further, because distribution companies sell to wholesale and retail customers, they face credit risk to a larger degree than do transmission companies whose sole customer is a distribution firm. More importantly, distribution companies are subject to operating leverage risk as they levy variable charges to cover fixed costs. Our view of the relative risks of electricity distribution vs. transmission is consistent with the opinion of the Alberta Utilities Commission (formerly the Alberta Energy and Utilities Board) in EUB Decision 2004-052 (July 2, 2004), page 48:

"The Board notes the consensus that electric distribution companies are subject to more business risk than electric transmission companies, principally due to their recovery of a significant amount of fixed costs in variable charges and their greater exposure to credit risks."

Electricity generation carries higher business risk than distribution along a number of dimensions. As explained above, because it is not a natural monopoly, generation faces potential competition from independent electricity producers locally as well as from generating facilities in neighboring provinces or states. Generation also carries a higher degree of operating leverage as a result of a higher level of fixed assets and more complex technology. On the production side capacity risk arises from unplanned outages, fuel costs and water availability. Further electricity generators are subject to risks from unplanned costs of asset retirement and construction of new generating facilities. Both DBRS and Ms. McShane agree that, as an industry sector, electricity generation is the most risky.[27]

3.5 BOND RATINGS AND CAPITAL STRUCTURES FOR CANADIAN UTILITIES

In this section we examine the bond ratings and capital structures, both actual and allowed for a sample of Canadian utilities. Our purpose is to develop benchmarks of capital structures for different segments of the industry. With these benchmarks in hand, we can then draw on our analysis of business risk above to recommend an appropriate equity ratio for OPG Hydro, OPG Nuclear and for OPG's total regulated rate base.

Beginning with bond ratings, Schedule 3.2 displays Dominion Bond Rating Service (DBRS) and Standard & Poor's (S&P) bond ratings in March 2008 for our

[27] Ontario Power Generation Inc., DBRS Rating Report, November 30, 2007, page 4 and Ms. McShane's Evidence, EB-2007-0905, Exhibit C2, Tab 1, Schedule 1, pages 77-78.

eight Canadian utilities and their regulated subsidiaries spanning different parts of the industry: gas, electric and pipelines. These companies represent a current sample of utilities with publicly traded shares. In forming this sample we seek to measure ratings and financial ratios for the traded entity associated with the regulated utility. In focusing on traded companies, our goal is to maintain sample consistency throughout our evidence. We recognize, however, that many of the traded companies include nonregulated businesses in addition to the regulated utility. We control for any bias by commenting on the differences as well as comparing our conclusions to those drawn strictly for regulated entities.

The bond ratings are from the websites of DBRS and S&P. Starting with the DBRS ratings, Schedule 3.2 shows that these range from A for Canadian Utilities, Enbridge, Newfoundland Power and TransCanada Corporation down to BBB (low) for Pacific Northern Gas. The Schedule shows that the typical Canadian energy utility is rated A (low) by DBRS. We next turn to the S&P ratings and make a similar comparison. The S&P ratings for the utilities in our sample range from A for Atco and Canadian Utilities down to BBB for Emera, Nova Scotia Power, Maritime Electric and TransAlta. S&P does not rate Pacific Northern Gas or the Fortis subsidiaries. The Schedule shows that the typical Canadian energy utility is rated A- by S&P.

The next step is to examine the actual, long-term capital structures of the companies in our sample for 2005 through 2007, the latest years for which data are available in the *Financial Post Advisor* and company annual reports. These ratios show common equity, long-term debt and preferred shares as percentages of long-term capital excluding short-term debt. Focusing on the 2007 common equity ratios, Schedule 3.3 reveals that there is considerable variation across companies from a high of 57.41% for TransAlta to a low of 31.75% for Atco. The average percentage of common equity was 41.92% in 2007 up slightly from 41.08% in 2005.

In addition, Schedule 3.3 shows the percentages of long-term debt and preferred shares (separated from common equity) in the capital structures of these companies. Again, there was considerable variation in the proportionate use of financing across companies. On average, the companies employed 54.41% long-term debt and 3.66% preferred shares in 2007.

The presentation of ratios for the same group of companies continues in Schedule 3.4. The first three columns show the coverage ratio, EBIT/Interest expense.[28] The average coverage ratio was 2.68X in 2007. The next three columns display cash flow to debt which averaged 21.43X in 2007.[29]

The schedules show that, from the vantage point of DBRS, Canadian Utilities, Enbridge, Newfoundland Power and TransCanada Corporation are the only companies which enjoy an A credit rating. The other companies are all rated A (low) or lower. For S&P, only two companies in our sample (Atco and Canadian Utilities) are rated A. As stated earlier, the typical company is rated on the borderline between A(low) and BBB (high) by DBRS and given a marginally higher A- rating by S&P for its smaller set of ratings. Of the eight traded companies and five subsidiaries in our sample, six received a rating of BBB from at least one of the agencies. Yet, despite their lower ratings, these companies have experienced no difficulties in accessing capital markets to raise long-term financing. This conclusion was not contradicted by Ms. McShane in her responses to Pollution Probe Interrogatory #54.[30] We conclude that the experiences of the companies in Schedules 3.2 - 3.4 suggest that a bond rating of BBB or higher is sufficient to maintain good access to capital markets.

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[28] EBIT are earnings before interest and taxes.
[29] Cash flow from operations divided by the sum of long- and short-term debt. The result is expressed as a percentage.
[30] Ms. McShane's Response to Pollution Probe Interrogatory #54, EB-2007-0905, Exhibit L, Tab 12, Schedule 54, page 1 of 1.

Schedule 3.4 also contains data on ROEs for the companies in our sample which support our argument that a bond rating of BBB or above is sufficient for a regulated utility. The ROE figures for 2005 through 2007 show that all of the companies earned positive ROEs in all three years. Further, a 2001 study on the Canadian electric utility industry by DBRS concludes that actual earned ROEs typically exceed ROE targets set by regulators.[31]

In Schedule 3.4 we update this comparison for 2007 and broaden it beyond DBRS' focus on electric utilities to encompass our sample. The update shows that utilities continue to enjoy typical earned ROEs in excess of the target ROEs allowed by regulators. Turning to the details, we conduct our update for 7 of our eight sample companies for which we have data on allowed returns. For two companies, Atco and Fortis, we have allowed returns by divisions giving us a sample of 11 comparisons. The average 2007 allowed return for this sample was 8.75% while the average actual ROE for the consolidated company was 12.03%. The difference, 328 basis points represents the outperfomance of allowed returns. Further, only 1 of our 11 regulated companies failed to achieve an actual ROE higher than its allowed rate. This strongly suggests that having a bond rating of BBB did not impede these companies from profitably conducting their businesses.

3.6 COMMON EQUITY RATIO BENCHMARKS

Our discussion shows that the typical Canadian utility in our sample has a bond rating of A (low) from DBRS and A- from S&P. Further, a number of companies have BBB ratings. While OPG falls into this range with a bond rating of A (low) from DBRS and BBB+ from S&P, its bond rating is enhanced by the support it receives from the Province of Ontario. Further, ownership by the

[31] G. Lavalee, M. Kolodzie and W. Schroeder, The Canadian Electric Utility Industry, Dominion Bond Rating Service, November 2001, p. 49.

Province of Ontario impacts the goals of the company according to The Government Backgrounder (23 February, 2005) which stated:[32]

> "The Ontario government has established prices for electricity produced by Ontario Power Generation (OPG) effective April 1, 2005. These prices are designed to:
>
> a) Better reflect the true cost of producing electricity
>
> b) Ensure a reliable, sustainable and diverse supply of power in Ontario
>
> c) Protect Ontario's medium and large businesses by ensuring rates are stable and competitive
>
> d) Provide an incentive for OPG to contain costs and to maximize efficiencies
>
> e) Allow OPG to better service its debt while earning a rate of return that balances the needs of customers and ensures a fair return"

Under the stand-alone principle of regulation, we must set aside the impact of provincial ownership of OPG and assess a fair capital structure from the standpoint of an investor-owned utility of comparable risk. This standard is provided by our sample in Schedule 3.2. Our analysis establishes that the sample represents a group of companies which, with appropriate adjustments discussed below, can proxy for the risk that would be faced by OPG if it were investor owned. Mindful of the goals set by the province but emphasizing the stand-alone principle, we use this sample to establish an appropriate capital structure for OPG.

3.6.1 Sample Benchmarks

First, we turn to Schedule 3.3 where we observe that the average actual equity ratio for utilities in our sample was 41.92% for 2007, the most recent year for which we have data. This represents one useful benchmark for the equity

[32] Board Interrogatory #10.

ratio for a Canadian utility. Other benchmarks are helpful for two reasons. First, like any sample average, our average equity ratio depends on the sample drawn and can vary somewhat for this reason. Second, as we indicated earlier, the average is based on equity ratios for traded companies which include nonregulated activities which are likely to be more risky than regulated utilities.

As a check on our calculations we examine the equity ratios allowed by various Canadian regulatory bodies for the companies in our sample for which we obtained data from past decisions. The sample includes Atco Electric Transmission and Distribution, Atco Gas and Pipelines, Enbridge Gas Distribution, Emera (Nova Scotia Power), Fortis Alberta, Fortis British Columbia, Maritime Electric, Newfoundland Power, Pacific Northern Gas, TransAlta, and TransCanada Pipelines. In Schedule 3.6, we report the average allowed equity ratio for these 13 companies as 39.40%. The analysis in Schedule 3.5 reinforces our conclusion that the average "generous" equity ratio for our sample of electric and gas utilities is around 39%.

We call this average equity ratio "generous" because it represents the result of a regulatory process in which decisions by regulatory bodies take as input the views of opposing parties each representing its own interest. We already showed how the regulatory process may be regarded as generous as it almost always results in the regulated companies earning an ROE in excess of the allowed return. Focusing the discussion of generosity on the common equity ratio leads to a similar conclusion. Regulated utilities have little incentive to optimize the use of debt in their capital structures. Having a capital structure with insufficient debt increases the weighted cost of capital because equity is the most expensive form of financing. In the case of regulated utilities, this "extra" cost associated with insufficient debt may be recovered through the process of regulation. If the company can persuade its regulator to approve this unwarranted extra equity, there is no cost to the company from a higher cost of capital. If this occurs, then the regulated company has unused debt capacity which can be a benefit to the parent holding company. The assets of the regulated utility can then serve as collateral to increase the borrowing power of the unregulated part of the holding company adding value for the shareholders. If this occurs, the shareholders gain unfairly at the expense of the customers of the regulated utility who have to pay higher rates to "compensate" the regulated utility for the cost of carrying unwarranted extra equity.

Returning to the discussion of benchmarks, we can develop another benchmark common equity ratio by focusing on one company from Schedule 3.5: ATCO Pipelines. We select ATCO Pipelines because it represents an example of a utility with greater business risk than a relevant set of comparison companies drawn from different segments of the utility industry in Alberta – the eleven utilities included in the AEUB's Generic Decision 2004-052. In that hearing, we recommended a common equity ratio for ATCO Pipelines of 40%, Ms. McShane recommended 50% and the Board awarded 43%. These numbers are drawn from Table 8 on page 35 of the Decision. We also identified AltaGas Distribution as a company with business risk well above the average and recommended an equity ratio of 40%. The Board awarded 41%. Based on these numbers and recalling our earlier discussion of "generosity" in past decisions, we regard 40 to 43% as an appropriate range for a higher risk utility.

We summarize our discussion of utility industry benchmark equity ratios as falling into a range of 39% to 43%. We form three estimates of the appropriate equity ratio for a utility. The first is 41.92% (Schedule 3.2) and represents the average of actual equity ratios for eight traded utility companies. The second estimate is the average equity ratio allowed 13 regulated entities within these companies by their regulatory boards of 39.40% (Schedule 3.5). The third estimate is the range allowed by the AEUB for two high-risk utilities of 40 to 43%. These benchmark equity ratios all fall in a range of 39% to 43%.

3.6.2 Relating the Benchmarks to OPG Hydro

In order to use benchmarks to set a recommended capital structure for OPG's two types of assets, it is necessary to draw on our earlier business risk analysis. Our analysis of the business risk faced by OPG Hydro assesses this risk as low to moderate – higher than that of a distribution utility and somewhat above the business risk of an integrated electric utility. This suggests that a fair common equity ratio for OPG Hydro should be at 40%, just below the middle of our range.

To explore the reasonableness of this conclusion, we reconsider our four benchmarks in turn. Our first benchmark, the average of actual equity ratios for 8 traded utilities is 41.92%. These companies are transmission, distribution or integrated utilities. However, because this measure also includes capital for unregulated activities which tend to be riskier than regulated businesses, we believe that it exceeds the appropriate level of equity for an average-risk utility. We confirm this view when we look next at our second benchmark of 39.40% which we regard as a generous measure of an appropriate capital structure. Given our view that OPG Hydro's level of business risk is above those of transmission, distribution and integrated utilities in our sample, our second benchmark indicates that a level of equity of no less than 39% is required.

We reinforce this view with our third benchmark of 40 to 43% equity allowed by the AEUB for high-risk Alberta utilities. Given, OPG Hydro's level of business risk, we believe that its target equity ratio should fall into this range.

Schedule 3.7 summarizes this discussion and restates our recommendation to set the common equity ratio for OPG Hydro at 40%.

3.6.3 Relating the Benchmarks to OPG Nuclear

We take a similar approach in reaching a recommendation for the equity ratio for OPG Nuclear. As we discuss above and summarize in Schedule 3.7, OPG's nuclear assets carry higher levels of operational risk compared to its hydro assets. Further, regulatory risk associated with environmental and safety issues are also elevated compared to that of OPG Hydro. Our analysis rates the business risk of OPG's regulated nuclear assets as moderate (2.3 on our 5 point scale).

Schedule 3.7 shows that this business risk rating for OPG Nuclear exceeds the rating for OPG Hydro (1.8). It also signals that OPG Nuclear bears higher business risk than generic integrated companies (rated 1.5) or generic distribution utilities rated (1.4). The higher business risk of OPG Nuclear should translate into a significant increase in its common equity ratio on the order of 5-10% over that for OPG Hydro producing a recommended equity ratio for OPG Nuclear of 45 to 50%. In the interests of conservatism and to ensure fairness to the shareholder, we recommend the higher number of 50% for the equity ratio.

3.6.4 Recommended Capital Structure for OPG's Overall Rate Base

In order to achieve an overall recommended capital structure for OPG's rate base we calculate a weighted average of our individual capital structures using the asset breakdown in the Electricity Restructuring Act of Ontario of 2004 which set OPG's prices for electricity for 6,606 MW from regulated nuclear generation and 3,332 MW for hydro generation. These two sources total 9,938 MW of which 66.47% is nuclear and 33.53% hydro. Applying these weights to our two separate capital structure recommendations results in an overall rounded recommended equity ratio of 47% for OPG's rate base.[33] We summarize our analysis in Schedule 3.7.

3.6.5 Capital Structure Impact of Fixed Charge for Nuclear Assets

As stated earlier, the analysis on which we predicate our recommended capital structure assumes that the Board grants OPG's request for a 25% fixed charge for nuclear assets. Should the Board deny this request the impact would be to reduce risk mitigation. In our framework, this falls under the deferral account category in the OPG Nuclear column Schedule 3.1. Under the scenario in which the Board disallowed OPG's request for a 25% fixed charge, business risk would be increased raising the rating for this category from Low (1) to Moderate (3). As a result the overall business risk ranking for OPG Nuclear would increase to 2.6. Although this ranking is still within the moderate range, we would move our capital structure for OPG Nuclear from 50 to at most 53% to reflect the increase in risk. Using our weighted average approach, the result would be to increase the recommended common equity ratio for OPG's regulated assets to 49%.[34]

3.6.6 Projected Coverage Ratios

Our recommendation for OPG's overall capital structure flows from our analysis of the business risks of its two types of assets as well as from our review of appropriate industry benchmarks. Those benchmarks include bond ratings and we concluded above that a rating of BBB would be sufficient to allow a stand-

[33] In her Response to Pollution Probe Interrogatory #2, Ms. McShane uses different weights: 45% nuclear and 55% hydro based on her analysis of the 2009 forecast rate base. Repeating our calculations with her weights produces a lower overall rounded equity ratio of 45%. We use the higher weight of nuclear assets from the 2004 Act so that our weighted estimate will capture any possible future increase in the percentage of nuclear assets.

[34] Reworking the overall cost of capital for the rate base for 2008 using the increased common equity ratio, shows that the cost of capital would increase by 3 basis points from 6.39% (from Schedule 3.8) to 6.42%. For 2009, the overall cost of capital for the rate base would increase by 2 basis points from 6.55% (from Schedule 3.8) to 6.57%.

alone utility to conduct its business properly and to access capital markets. To show that our recommendation of 47% equity for the rate base is not incompatible with a BBB rating, we calculate the implied coverage ratios for 2008 and 2009 in Schedule 3.8.

To illustrate, we explain our calculations for 2008 in detail. We start with the rate base of $7,400.8 M from Table 3 from EB-2007-0905, Exhibit C1, Tab 2, Schedule 1, Updated 2008-03-14. We also use OPG's estimate of the cost of total debt for 2008 at 5.76%. We fill in our estimate of the fair return on equity from Section 4 of this evidence as 7.10% for 2008. Next we enter our recommended capital structure of 47% common equity and 53% debt. Finally, we use these numbers to calculate the allowed cost of capital for debt and equity. Summing these two amounts, we compute the total allowed cost of capital for the rate base as $472.9M.

To obtain a projected coverage ratio for the rate base, we divide the total allowed cost of capital (allowed earnings on rate base) of $472.9M by the total cost of debt of $225.9M to obtain a projected coverage ratio for rate base of 2.1X. For 2009, we perform a similar set of calculations replacing the inputs we used from Table 3 for 2008 with a similar set of inputs from Table 2 for 2009. We use the same capital structure for 2009 and set the cost of common equity at 7.25% as recommended in Section 4 of this evidence. As Schedule 3.8 shows, the projected coverage ratio for 2009 is 2.1X, the same as for 2008.

In brief, the analysis in Schedule 3.8 shows that our recommended capital structure implies an interest coverage ratio of 2.1X for OPG's rate base. We compare this projected coverage ratio against the actual coverage ratios for traded utilities in our sample. Schedule 3.1 reveals that 4 traded companies in our sample are rated BBB by at least one rating agency: Emera Inc., Fortis Inc., Pacific Northern Gas and TransAlta. In Schedule 3.3 shows that the 2007 coverage ratios for these four companies were 2.91 (Emera), 1.70 (Fortis Inc.), 2.10 (Pacific Northern Gas) and 3.17 (TransAlta).

Comparing these ratios to our projection for OPG's rate base, we conclude that the projected coverage ratio for OPG of 2.1X falls into the middle of the range of observed coverage ratios for these 4 BBB rated companies. As far as it goes, this comparison suggests that there is no reason to believe that OPG as a stand-alone company with our recommended 47% common equity in its capital structure could not achieve a BBB bond rating. We qualify this conclusion by noting that rating agencies consider other factors in addition to coverage ratios in setting ratings. A further qualification arises from our discussion in Section 2 of the shortcomings of bond ratings as a timely measure of risk.

4. RATE OF RETURN ON COMMON EQUITY FOR 2008 AND 2009 TEST YEARS

4.1 OVERVIEW OF THIS SECTION

In this section, we begin with a discussion of the general regulatory principles that are appropriate in conducting our fair rate of return analysis. As discussed in Section 1 of our evidence, our general approach is to determine the appropriate return on equity for a utility of average investment risk (henceforth referred to as the "average-risk utility"), and then to determine a capital structure for the applicant utility (OPG) that accounts for any difference in its business risk from this hypothetical benchmark average-risk utility.

After discussing general regulatory principles, we discuss the two main methodologies for estimating a forward-looking market equity risk premium or MERP. They are *ex post* measurement methodologies that generate a "historical or *ex post* MERP" that leads to the generation of an "*ex ante* MERP", and the *ex ante* methodology that generates an "*ex ante* MERP." Based on the merits of the various estimation methods used under each of these methodologies, we recommend that four of these estimation methods have sufficient validity to be used in our determination of the MERP and/or market return in a forward-looking sense. We then present our implementation of each of these four estimation methods to arrive at an appropriate return on equity (henceforth ROE) for OPG for the 2008 and 2009 test years.

4.1.1 Methods to Estimate the Market Equity Risk Premium (MERP)

The first estimation method is the Equity Risk Premium Estimation Method that generates an *ex ante* MERP estimate from an examination of the historical (*ex post)* MERP and expected future economic and market conditions. To this end, we estimate the required MERP for Canadian equities based on historical estimates for Canada and the U.S., and survey recent evidence that suggests that previously estimates using realized returns as a proxy for expected returns

TAB 3

got an upward-sloping relationship and a downward-sloping relationship, but you form one line? What do you get? You get something in between.

So basically, what happens generally is, you find that the risk premia are either generally insignificant, sometimes positive, sometimes negative.

But again the literature helps us. If we go back to a study in one of the major journals of finance, by Pettengill et al in 1995, they condition the CAPM based on whether the market return is above or below the risk-free rate. What do they find? You get a positive risk premia. The CAPM is supported if you do the proper test of the CAPM.

I have done some studies in that area for Canada. It works. I've seen studies for almost all kinds of countries, around the world, and it is one of the few models that seems to work fairly well.

The other thing that we've pointed out in our evidence is more recent studies. For example, we cite a paper by Ang et al. They find that, again, if you look at a Fama-French -- a lot of the people say the Fama-French three-factor model is better than the CAPM. In actual fact, more recently, the only factor that is priced is the market factor.

So while the CAPM is not perfect, it does a fairly good job and it works fairly well in terms of forward-looking.

MR. ALEXANDER: That concludes the questions I have with respect to some aspects of Ms. McShane's testimony.

Before I conclude my examination-in-chief, do either you -- do either of you have any further comments or, any further comments you would like to add?

DR. KRYZANOWSKI: We do not.

MR. ALEXANDER: Thank you, Dr. Roberts. Thank you, Dr. Kryzanowski.

Subject to any questions from the Board, I have no further questions-in-chief.

MR. KAISER: All right. Thank you.

Mr. Warren, any questions?

MR. WARREN: No, thanks.

MR. KAISER: Mr. Buonaguro?

MR. BUONAGURO: No.

MR. KAISER: Dr. Schwartz?

DR SCHWARTZ: No.

MR. KAISER: Ms. Campbell?

MS. CAMPBELL: No, thank you.

MR. KAISER: Mr. Penny.

CROSS-EXAMINATION BY MR. PENNY:

MR. PENNY: Gentlemen, my name is Michael Penny. I represent OPG in this proceeding.

I am going to be making reference to your prefiled evidence and to, probably, to some material in this binder called "OPG's examination brief for cost of capital" and probably to some material in this volume 2 of that.

Do you have those volumes with you?

DR. ROBERTS: Yes, we do.

MR. PENNY: I am going to try and remember, if I am citing numbers, to use your updated evidence, but please don't hesitate to correct me if I am using the old risk-free rate and the old recommendation.

I wanted to start with just a few issues of principle. You agree that the capital structure for OPG should be determined on the stand-alone principle, meaning we must set aside the impact of provincial ownership?

DR. ROBERTS: Yes, we do.

MR. PENNY: And under the stand-alone principle, you say one should assess an appropriate capital structure from the standpoint of an investor-owned utility of comparable risk?

DR. ROBERTS: That's right.

MR. PENNY: I wanted to refer to the DBRS report, which I have reproduced in my bundle at tab 11 of the larger document. You are familiar with this?

DR. ROBERTS: Yes.

MR. PENNY: In fact, you cite it yourself, I think, in your evidence.

DR. ROBERTS: Yes, we do.

MR. PENNY: The report says that the current rating takes into account OPG's improved financial profile on a stand-alone basis.

DR. ROBERTS: That's right.

MR. PENNY: All right. And they give OPG an A low rating; right?

DR. ROBERTS: That's correct.

MR. PENNY: If you look at the financial information in the summary on the first page, on a consolidated basis, DBRS is showing actual debt levels at 36 to 44 percent in 2005 to 2007; is that right?

DR. ROBERTS: That's the way it is showing here, yes.

MR. PENNY: That means consolidated equity ratios were in the 56 to 64 percent range?

DR. ROBERTS: Yes. That's what it is showing here.

MR. PENNY: All right. Then the interest coverage ratios were, as I read this, 4.6 in 2005?

DR. ROBERTS: Yes, that's what it shows here.

MR. PENNY: 3.7 in 2006?

DR. ROBERTS: Yes.

MR. PENNY: And 3.27 for the 12 months ended September 30, 2007?

DR. ROBERTS: That's what DBRS has calculated, yes.

MR. PENNY: All right, thank you.

You agree, I understand, with the commonly-held view that transmissions or wires businesses carry the lowest -- that a transmission wires business carries the lowest risk in the utility category, followed by distribution, and then by generation?

DR. ROBERTS: That's right.

MR. PENNY: And, indeed, I think you say even looking at hydro generation, OPG's hydro -- OPG hydro's level of business risks are above those of transmission, distribution and integrated utilities?

DR. ROBERTS: Correct.

MR. PENNY: OPG's nuclear power generation business carries an even higher level of risk overall compared to OPG hydro?

DR. ROBERTS: That's what we say in our evidence, yes.

MR. PENNY: Yes. Do you agree that, all else equal, the higher the business risk a firm has, the higher the financial metrics, like interest coverage ratios, need to be in order to achieve investment grade ratings?

DR. ROBERTS: The higher the risk, the higher the ratio would have to be in order to achieve investment grade rating?

MR. PENNY: Yes.

DR. ROBERTS: I'm not sure I understand that.

MR. PENNY: Well, let me try it one more time. If you don't understand it, then that's fine.

DR. ROBERTS: I don't understand it necessarily would be the case.

MR. PENNY: Okay. So you're not in a position to agree with that proposition?

DR. ROBERTS: No.

MR. PENNY: It might be true; it might not?

DR. ROBERTS: It might be true. It might not be true.

MR. PENNY: Okay, fair enough.

Let's just flip quickly to, in your evidence, schedule 3.4, which is at page 204.

DR. ROBERTS: All right. We have it.

MR. PENNY: I just wanted to confirm that the -- this, by the way, is a sample of selected utilities that you use in your analysis.

As I understand it, you have chosen this selection because they are holding companies and are publicly traded?

DR. ROBERTS: Because they're publicly traded, they happen to be holding companies in most cases, yes.

MR. PENNY: Okay. But do I have it right that the reason that you have chosen this particular group is because they're publicly traded, because that gives you access to information that you may not otherwise have?

DR. ROBERTS: Correct.

MR. PENNY: But these are not necessarily the utilities themselves, and in most cases it's not?

DR. ROBERTS: Yes. We say that in our evidence. I could find the citation, if you like.

MR. PENNY: I just want to be clear that we're on the same page.

DR. ROBERTS: Yes.

MR. PENNY: I'm not suggesting --

DR. ROBERTS: Another reason why we use it is because we want to be consistent in using the same companies in this part of our evidence that we use in the other part of the evidence where we estimate the betas, and in order to estimate betas you have to have publicly-traded information.

MR. PENNY: Understood.

My only -- with that background, just so it is clear what we're talking about now, your average for this group interest coverage ratio for 2007 is about 2.7. It is about

2.68 percent?

DR. ROBERTS: Yes.

MR. PENNY: And that is, I think, if you recall, quite similar, actually, to Ms. McShane's schedule 25, in which I think she said -- she estimated a 2.6 percent coverage ratio for all electric utilities and 2.5 for all utilities?

DR. ROBERTS: Similar. Ms. McShane had a different sample, but a lot of the companies were the same.

MR. PENNY: Yes. Let me try another proposition, Dr. Roberts. Are you able to agree that, all else equal, higher equity ratios will produce higher coverage ratios, not lower coverage ratios?

DR. ROBERTS: That is certainly true in the context of deemed equity ratios in regulation. It might or might not be the case in terms of publicly-traded companies.

MR. PENNY: Fair enough. Okay, I think that's -- I think we're in agreement.

DR. KRYZANOWSKI: It also depends on the embedded cost of debt.

DR. ROBERTS: Yes. It assumes that as is usually but not always the case, that the cost of equity is higher than the historical embedded cost of debt.

MR. PENNY: Fair enough. As you say, that is usually the case?

DR. ROBERTS: And it is the case here.

MR. PENNY: It is the case here.

DR. ROBERTS: But not necessarily the case always, right.

MR. PENNY: Yes. But it is the case for any regulated utility that you are aware of?

DR. ROBERTS: No, that's not true. The last case we did in the Northwest Territories, it was not the case.

MR. PENNY: Okay. So there are exceptions to the general proposition?

DR. ROBERTS: Yes, that's correct.

MR. PENNY: Fair enough. Do you or...

There's been, of course, a discussion in your evidence and a discussion in the evidence of some others a question about whether a BBB rating is adequate for certain utilities for the purposes of raising capital, and so on.

You obviously address that in your evidence. You are familiar with this issue?

DR. ROBERTS: Yes, we are.

MR. PENNY: What I wanted to ask you is: Do you know what percentage of corporate debt was issued in Canada, say, in the recent past, to issuers that were rated BBB or lower?

DR. ROBERTS: I don't have that number, no.

MR. PENNY: Would you turn up in tab 1 of this brief, of the larger brief, at page 15 -- well, the cover page is at page 14. This is an article in the Canadian Investment Review written by someone named Marlene Puffer, who is said to be the managing director of Twist Financial Corporation.

DR. ROBERTS: No, Marlene Puffer -- she is formerly a professor at the University of Toronto.

MR. PENNY: Perfect. So you know this person?

DR. ROBERTS: Yes.

MR. PENNY: She says at page 15 of the brief, page 23 of the article, in the right-hand column that:

"The BBB sector has expanded to 4 percent of the market, namely, under ten years, but is still small in Canada."

DR. ROBERTS: Yes, I see that.

MR. PENNY: Are you prepared to accept that as an accurate statement?

DR. ROBERTS: Yes. But it also continues on the next page. I think we should --

MR. PENNY: Fair enough. Can I get an answer to my question, and then you can give an explanation? My question was: Do you accept that?

DR. ROBERTS: I am prepared to accept it as an accurate statement of the present situation. However, it is not a completely accurate statement of the future, as it points out at the top of page 25 of the article --

MR. PENNY: Yes.

DR. ROBERTS: -- where it says that this sector is expanding, and then it tells you the pension funds are getting into this area.

MR. PENNY: Yes.

DR. ROBERTS: I might add the date of this article was Fall 2006.

MR. PENNY: Yes.

DR. ROBERTS: Since that time, based on my -- while I haven't done a detailed study of this sector of the market, we know that it is a higher risk sector, that along with private equity, has expanded.

So I would expect that if Ms. Puffer updated this study, you would find that that percentage is higher than it was in 2006.

MR. PENNY: Well, but please, Dr. Roberts, we don't want to speculate. I have asked you whether you know what the percentage is and you have said you don't know --

DR. ROBERTS: I don't know.

MR. PENNY: -- correct?

DR. ROBERTS: I don't know; that's correct.

MR. PENNY: And let's move to a slightly different aspect of it.

I think you accept -- because I read this in an answer to one of your interrogatories -- that BBB rated companies typically pay more for debt than do A rated companies.

DR. ROBERTS: Yes.

MR. PENNY: But you, as I understand it, have not conducted any analysis of the actual dollar impact of a BBB rating as opposed to an A rating on the cost of debt in Canada?

DR. ROBERTS: That's correct.

DR. KRYZANOWSKI: I guess I've published some papers on debt, and basically one of the problems when you look at comparisons across different categories is: What does it include?

In a lot of cases, what it includes is a liquidity premium, and if you don't back out the liquidity premium, then it is hard to make a proper comparison across the different categories.

The other point I would make is, if you look at bank debt, a lot of the bank debt would be categorized as BBB. So it depends what you include in your definition.

MR. PENNY: Perhaps you could turn to tab -- if you still have tab 1 there, and turn to page 18.

DR. KRYZANOWSKI: Yes.

MR. PENNY: This is -- was at the time, I guess, a fairly -- at the time we pulled it, a fairly recent -- but now some time has gone by, but this is a May 12, 2008 RBC Capital Markets "New issue indicative spreads". You are familiar with documents of this type? I presume you'd look at them all the time?

DR. ROBERTS: Yes, we are.

MR. PENNY: If you would look with me at TransAlta Corporation, which is under the energy utilities column, just towards the bottom, they're BBB rated? By DBRS.

DR. ROBERTS: Yes.

MR. PENNY: And BBB by S&P. As I understand it, their 30-year spread as of that day was 380 basis points.

DR. ROBERTS: That's what it says here, yes.

MR. PENNY: And just to compare, we looked at Enbridge Gas Distribution. They're A rated by DBRS and by S&P. Well, A minus, I guess. Is that right?

DR. ROBERTS: Yes.

MR. PENNY: And their spread, as of May 12th, 2008 was 170 basis points. Right?

DR. ROBERTS: Are you talking about Enbridge Inc.?

MR. PENNY: Enbridge Gas Distribution.

DR. ROBERTS: Enbridge Gas Distribution. Yes, that's right.

MR. PENNY: Okay. Then if we looked as another comparator at Hydro One, do you see that?

DR. ROBERTS: Yes.

MR. PENNY: With A high and A from DBRS and S&P.

DR. ROBERTS: Mm-hmm.

MR. PENNY: And a spread on 30-year of 133 basis points.

DR. ROBERTS: Right.

MR. PENNY: I guess my question to you would be: Is a 350-point or 380-basis point spread or a 3.8 percent spread, is that, in your opinion, indicative of a low-risk utility?

DR. ROBERTS: No. I also see Enbridge Inc., which I thought you were referring to before.

MR. PENNY: Yes.

DR. ROBERTS: Which has, according to this was rated A and A minus, with a spread of 250.

So while I'm happy to agree, it is clearly the case that a BBB has a higher yield than an A rated bond, you can't reach a conclusion about the numerical value by selecting individual cases from a short list like this, because if you did it with ones that you did, you get one answer. If I pick on Enbridge, I get an answer that is a lot lower. So you can't really quantify it based on that.

DR. KRYZANOWSKI: Not only that. You only have one observation. It is one point in time.

MR. PENNY: Absolutely. It is May 12th, 2008.

DR. KRYZANOWSKI: So you know --

MR. PENNY: Isn't that right?

DR. KRYZANOWSKI: Who would actually make a determination on one observation? You know, these differences vary over time.

MR. PENNY: Mm-hmm.

DR. ROBERTS: We're not trying to be difficult. We're happy to agree that BBB debt has got a higher yield. Where we can't agree is with your numerical calculation, for the reasons that we stated.

MR. PENNY: All right.

Let's go back to your schedule 3.2, .3 and .4 for a moment.

I just wanted to make sure that we were on the same page, in terms of what we're talking about.

As you move through from 3.2 to 3.5, it's the same group, right? And so what I actually want to look at is on 3.5. But let's just review the ratings so that we've got that at the same time.

So ATCO Limited is rated A -- I'm just going to deal with DBRS, just to keep this manageable, but it is A low?

DR. ROBERTS: Yes, that's what we see here.

MR. PENNY: Canadian Utilities is A?

DR. ROBERTS: That's right.

MR. PENNY: And Emera is BBB high?

DR. ROBERTS: That's right.
MR. PENNY: And Enbridge -- you say Gas Distribution, but it wasn't clear to me whether you were talking about EGD or Enbridge Inc.
DR. ROBERTS: According to this table, and of course this was as of the date of the table, was March 27th of this year, both of those companies had the same rating, so we just included them in the same box to save space.
MR. PENNY: All right. I understand. Thank you. So they're A?
DR. ROBERTS: Yes.
MR. PENNY: Then we have Fortis Inc., BBB high?
DR. ROBERTS: Right.
MR. PENNY: Then P and G, BBB low?
DR. ROBERTS: Right.
MR. PENNY: Then finally, TCPL at A?
DR. ROBERTS: Yes.
MR. PENNY: Okay. And the average, you say, of those consolidated companies, the average earning is 12, roughly 12 percent.
DR. ROBERTS: I'm sorry, what --
MR. PENNY: I'm at 3.5.
DR. ROBERTS: Okay. So from 3.5.
MR. PENNY: That's at page 205.
DR. ROBERTS: The actual ROE for the consolidated company was about 12 percent, yes.
MR. PENNY: Yes. And the three BBBs -- that was Emera, Fortis and P and G -- they're all, they're the ones

that are below the average.

DR. ROBERTS: You're getting that from 3.4?

MR. PENNY: 3.5. I'm just looking at the numbers and Emera is 10.93. That is below 12 percent.

DR. ROBERTS: Yes.

MR. PENNY: And Fortis Inc. is 9.99. That's below 12 percent.

DR. ROBERTS: Yes.

MR. PENNY: Right? And P and G is five, and that is obviously below the 12 percent.

DR. ROBERTS: Yes. Okay. Thank you for helping me with that.

MR. PENNY: So those are the three below the average.

MR. RUPERT: Mr. Penny, is TransAlta also in that group? Just so I am following your analysis here.

MR. PENNY: Yes, it is.

DR. ROBERTS: It is also below.

MR. PENNY: Sorry, Mr. Roberts, I missed what you just said. It is below?

DR. ROBERTS: Well, Mr. Rupert pointed out, while it is true that those three companies that you picked, because they are BBB, are below the average, there are other companies in the table that are not rated BBB that are also below the average, as he just pointed out.

MR. RUPPERT: I just wanted to understand, Mr. Penny. There is the fourth one, I think you've clarified it, that the TransAlta is also BBB in that table on page 202.

MR. PENNY: Yes, it is.

MR. RUPERT: Okay. I wasn't sure whether you were excluding that for a reason. That was the --
MR. PENNY: No, I wasn't.
MR. RUPERT: Okay.
MR. PENNY: But I guess I skipped over it because TransAlta is not regulated.
DR. ROBERTS: Okay.
MR. PENNY: Is that your understanding?
DR. ROBERTS: That's my understanding, yes.
MR. PENNY: Okay. But you will have to help me with this. TransAlta Corporation, you're showing actual ROE for a consolidated company at 13 percent; correct?
DR. ROBERTS: Yes.
MR. PENNY: And the average is 12.
DR. ROBERTS: Yes. But what I was trying to say was that other companies that are not rated BBB would not be below. Maybe I misspoke on that. So the ones that are BBB are Emera --
MR. PENNY: I think we decided it's Emera, Fortis, of the regulated ones, it's Emera, Fortis and P and G.
DR. ROBERTS: Okay.
MR. PENNY: My only point is --
DR. ROBERTS: You're right. I withdraw that. The other ones in the table are above average, correct.
MR. PENNY: All right. Thank you for that.
Would you also agree, if we just took Emera as an example, Nova Scotia, which owns Nova Scotia Power, would you agree with me that one of the contributing factors to

Emira having even the BBB high rating is that it has consolidated earnings on equity of almost 11 percent?

DR. ROBERTS: That is a positive factor. I would assume a bond rating agency would see it as positive.

MR. PENNY: I guess if the earnings weren't 10.93 percent, but were lower, it might not enjoy that. It would have an influence on their agency rating and it might not enjoy that BBB rating?

DR. ROBERTS: Yes. By itself it would, but clearly there are a number of other factors that might mitigate that.

MR. PENNY: Fair enough.

DR. KRYZANOWSKI: Not only that. Agencies say they're forward-looking and not backward-looking. There is some debate about that.

MR. PENNY: Dr. Kryzanowski, you're not suggesting that the bond rating agency doesn't care what the earnings are when coming up with the ratings, are you?

DR. KRYZANOWSKI: I mean, they look at past results, but they also try to determine whether or not it is going to persist in the future.

MR. PENNY: Yes.

DR. KRYZANOWSKI: So of course if you could earn more than what you are allowed consistently over time, that's a very positive factor.

MR. PENNY: I wanted to turn to that, because you -- in the context of these consolidated corporations -- I wonder if you wouldn't mind turning up tab 1, page 34 of the brief.

You are using ATCO Inc. in your sample?

DR. ROBERTS: That's correct.

MR. PENNY: I have just done an -- to make, I think, probably an obvious point, but a point, that ATCO is a diversified Canadian-based international group of companies; right?

DR. ROBERTS: Yes. We point this out in our evidence. I could find the citation, if you like.

MR. PENNY: No, that's all right.

If we look at the excerpt from the annual report, at page 35 it indicates that, as you have noted, the return was 16.7 percent. "This was achieved", it says -- sorry, I'm in the third box.

DR. ROBERTS: Yes, I see it.

MR. PENNY: "This was achieved even though the

> regulated utilities are subject to a formula-driven return on equity regime that resulted in a rate of 8.51 percent for 2007. Therefore, the overall ATCO rate of 16.7 was driven by results of the non-regulated entities in the company."

Do you see that?

DR. ROBERTS: Yes, I do.

MR. PENNY: Then if we flip to --

DR. ROBERTS: If you're finished with that, I have a comment about it.

MR. PENNY: Well, I didn't ask you if you had a comment on it. If your counsel wants to re-examine you on it, he is at liberty to do so.

DR. ROBERTS: Fine.

MR. PENNY: Would you flip to the next one, please, Enbridge Inc.?

DR. ROBERTS: Am I allowed to say that even though I see it does not mean that I accept this explanation that ATCO gave. It could be a number of reasons why this explanation about the regulated versus non-regulated is not the full story. And I would be happy to discuss that, if you like.

MR. PENNY: Well, I think we will come back to that, so I am sure you will get the -- let me just do it my way, if you don't mind, and then you'll get a chance to say what you want.

DR. ROBERTS: Of course, of course. I just am pointing out -- putting a marker there so we won't forget it, that's all.

MR. PENNY: Fair enough.

DR. ROBERTS: Thank you.

MR. PENNY: You will, I'm sure, get the opportunity, Dr. Roberts.

DR. ROBERTS: Thank you, Mr. Penny.

MR. PENNY: One thing about these hearings is that nobody walks away without getting to say what they want to say, within reason.

Enbridge Inc., the annual report for 2007, that's the next one?

DR. ROBERTS: Yes.

MR. PENNY: And, again, I think to make the obvious point, if we just look at page 37, across the top of the page, it is showing segmented information for that holding company?

DR. ROBERTS: Yes.

MR. PENNY: We see there is liquid pipelines, gas pipelines, sponsored investments, gas distribution services and something called international?

DR. ROBERTS: Yes. That's right.

MR. PENNY: So it is also a diversified business that carries on more than just regulated businesses?

DR. ROBERTS: It is.

MR. PENNY: Similarly, one of your other comparators was TransAlta, and at the next page I've got an excerpt from the TransAlta 2007 annual report. And if you flip to page 39 of the brief - it's page 27 of the report - it shows that TransAlta Corporation is -- consists of three subsidiaries, one a utilities corporation, one an energy corporation, and one a co-generation corporation; right?

DR. ROBERTS: That's correct.

MR. PENNY: The TransAlta Energy Corporation, among other things, has US, Mexican and Australian operations?

DR. ROBERTS: That's correct.

MR. PENNY: Now, in each case, you will agree with me that the earnings of these companies are derived from a mix of both regulated and unregulated operations?

DR. ROBERTS: I agreed to that before, and also pointed out that there could be a number of explanations in terms of the risk that we're going to talk about.

DR. KRYZANOWSKI: In fact, you mentioned Mexico and other countries. Those are countries with higher risk. So you can't just compare returns. You've got to look at risk-adjusted returns.

MR. PENNY: I am happy to do that. My only point is that those operations are not regulated, so we can't talk about deemed capital structure or allowed rates of return for those companies, correct -- for those operations, I mean. Do you agree with that?

DR. KRYZANOWSKI: You're alluding to the fact that these returns come from the non-regulated part of the utilities.

MR. PENNY: And you accept that?

DR. KRYZANOWSKI: What we're saying is that there might be good reason for that.

MR. PENNY: I'm not suggesting there isn't good reason for it. I'm simply asking you to agree that these returns are derived from businesses which are not regulated.

DR. KRYZANOWSKI: And I am not trying to argue with you but --

MR. PENNY: But you are, sir.

DR. KRYZANOWSKI: But, you know, we have to be able to provide our answers.

MR. PENNY: Let's do it this way. The earnings of the parent holding companies in total, while they include earnings from regulated operations, also include earnings from unregulated operations. We do agree about that?

DR. ROBERTS: Yes, we do.

MR. PENNY: And will you agree with me that any difference between allowed returns to the regulated business and the actual returns of the consolidated holding companies would, among other things, include the actual returns of the unregulated part of the business?

DR. ROBERTS: Yes. It says on page 47 of our evidence exactly that point.

MR. PENNY: And so you agree that you cannot conclude, if you go back -- if we go back to 3.5, that the entire difference between your 12 percent average under the consolidated company, and your 8.75 average for allowed returns, is attributable to so-called over-earning in the regulated business? Do you agree with that?

DR. ROBERTS: We cite in our evidence where we indicate on page 47 that we recognize that these are holding companies. We recognize that it is an imperfect comparison, and that's why we have -- use as one among a number of comparisons.

So while the comparison is not a perfect one, as you pointed out, is useful as input, along with other comparisons which offset the -- I guess every comparison you make has got some advantages and disadvantages that, all together, tell us the same story.

MR. PENNY: At page 49 of your testimony -- I think it is page 49. Yes, page 49. You are talking here about OPG Hydro, and you say:

"OPG Hydro's level of business risk is above

those of transmission, distribution and
integrated utilities in our sample."

Right?

DR. ROBERTS: Yes.

MR. PENNY: And one of the -- as I understand it, by integrated utility you mean a utility with distribution and generation facilities?

DR. ROBERTS: That's correct.

MR. PENNY: All right. In, I think it was, an answer to an interrogatory, you said that your benchmark integrated utility was Newfoundland Power?

DR. ROBERTS: That was one of the integrated utilities, I believe.

MR. PENNY: Okay. And it has a deemed capital structure of 44.5 percent?

DR. ROBERTS: Yes.

MR. PENNY: All right. And I asked -- were you here when I asked questions of Mr. Goulding yesterday?

DR. ROBERTS: I believe I was.

MR. PENNY: Maybe I don't need to repeat all of these, but in effect, I guess you're aware that while Newfoundland Power may technically be an integrated utility in the sense that it has some generation, that is a very small part of its business?

DR. ROBERTS: Yes. It is right in -- just without repeating it, the same comment I made before about problems with sampling applies here. It is an integrated utility. However, it is not ideally integrated in that it is one-third, one-third and one-third.

MR. PENNY: And you, I guess, you agree that it doesn't operate any large hydro generating stations, like the Beck Station or the Saunders Station?

DR. ROBERTS: I believe that the amount of generation is relatively small, much smaller than one-third that you would see in that ideal hypothetical integrated company.

MR. PENNY: Yes. In fact, I think we reviewed yesterday that it was in total, 140 megawatts came from a combination of some small hydro, gas and diesel.

DR. ROBERTS: I could accept that, subject to check.

MR. PENNY: And when I reviewed -- just sticking with Newfoundland Power for a minute -- you are aware that they have a number of deferral and variance accounts which reduce earnings variability?

DR. ROBERTS: Yes.

MR. PENNY: Okay. And they obviously run no nuclear business?

DR. ROBERTS: No.

MR. PENNY: And they, as I reviewed with Mr. Goulding yesterday, they have effectively no asset retirement obligations?

DR. ROBERTS: That's consistent with what we say in our evidence about the relative risk of integrated versus nuclear, as you just quoted.

MR. PENNY: All right. Then I just wanted to ask you about the risk assessment.

Just starting at section 3.3 -- you probably don't need to turn it up because my questions are at a general level, but you've got a section headed "framework for analysis". As I understand it, you have set up an analytical framework to assess utility business risk.

DR. ROBERTS: Yes.

MR. PENNY: And you use three major categories of business risk for utilities: market risk, operational risk and regulatory risk.

DR. ROBERTS: Yes.

MR. PENNY: And under "market risk" for the utilities, you put competition and demand risk and credit risk.

DR. ROBERTS: Yes. That's right.

MR. PENNY: Then under "operational risk", you put operating leverage risk, technology risk, capacity risk, and asset retirement and construction risk, and deferral accounts.

DR. ROBERTS: Yes. I am just referring to schedule 3.1, which summarizes that. Yes, that's correct.

MR. PENNY: Then under "regulatory", you've got primary regulation, and safety and environmental.

DR. ROBERTS: Yes. And there was one other category about deferral accounts that is also in there.

MR. PENNY: I think I mentioned that.

DR. ROBERTS: Sorry.

MR. PENNY: So you end up, as I understand it, you end up with nine individual risks covering the three categories?

DR. ROBERTS: That's correct.

MR. PENNY: Okay. And then you assign to each of these nine risks a scale of 1 to 5.

DR. ROBERTS: Yes, I do. The scale is intended to show where they are in the range of low, low to moderate, moderate, moderate to high and high. It's just sort of a way of keeping track of it.

MR. PENNY: I guess that is where I was going, is that the 1 to 5, there is no magic to that. It could have been 1 to 10 or one to 100 or whatever.

DR. ROBERTS: Well, it is based on a practice that Dr. Kryzanowski and I -- Dr. Kryzanowski developed, and he and I taught for a number of years, a course for the Institute of Canadian Bankers, for bankers across Canada, on solvency risk analysis, and it's based on some of the materials that were developed there and are widely used in the industry, this idea of a qualitative numerical ranking.

DR. KRYZANOWSKI: It's based on a book I wrote for the Institute. So it's a guide.

MR. PENNY: I asked a pretty simple question. I --

DR. ROBERTS: We're just saying we weren't the first to think of this, right? It is out there, and it's widely used in the industry.

DR. KRYZANOWSKI: Even some of the rating agencies sometimes use scoring models.

MR. PENNY: Mm-hmm. But not this particular model --

DR. KRYZANOWSKI: No, this particular one --

MR. PENNY: -- because as I understand it, you've never put this forward in a regulatory proceeding before.

DR. ROBERTS: We didn't want to -- since we're professors, we didn't want to be like the professors of the old days that made their notes on yellow papers and used the same lecture for 20 years.

MR. PENNY: Dr. Roberts, I'm not criticizing you for anything here. I just want you to confirm this in an analytical framework before --

DR. ROBERTS: I'm happy to confirm that, Mr. Penny.

MR. PENNY: And I think as you have already indicated, on this scale, you give 1 to low, 3 to moderate and 5 to high?

DR. ROBERTS: Correct.

MR. PENNY: Just coming back to this issue that you have not put forward this framework before, you haven't analyzed other specific utilities using this framework before either?

DR. ROBERTS: What we analyzed in the report were the sectors of the industry.

MR. PENNY: Yes.

DR. ROBERTS: But not specific utilities.

MR. PENNY: Right. So you haven't turned Northwest Territories Power through this model, or ATCO, or anybody else?

DR. ROBERTS: That's correct.

MR. PENNY: Okay. And just -- you should probably maybe keep the 3.1, because I think I am coming back to it, but I just wanted to confirm another basic principle, if you will, which is a reference from page 26 of your evidence.

DR. ROBERTS: Mm-hmm. We have page 26.

MR. PENNY: Do you have that? You will see that there's -- you quote from the Alberta Utilities Commission, in the middle of the page, to the effect that:

> "In the Board's view, setting an appropriate equity ratio is a subjective exercise that involves the assessment of several factors and the observation of past experience. The assessment of the level of business risk of the utilities is also a subjective concept. Consequently, the Board considers that there is no single accepted mathematical way to make a determination of equity ratio based on a given level of business risk."

DR. ROBERTS: That is correct.

MR. PENNY: And just as a matter of substance, I don't read your evidence as necessarily disagreeing with that.

DR. ROBERTS: No. Our evidence is making that point. We're quoting the Board in support of our view.

MR. PENNY: Right. Your nine categories is your attempt at making sure that we ask all of the right questions?

DR. ROBERTS: You could think of it that way.

MR. PENNY: Uh-huh. And the 1 to 5 scale is your way of assessing a relative ranking for a particular utility, within these categories.

DR. ROBERTS: Yes.

MR. PENNY: But am I right that when -- just taking an example -- when you actually come to, say, OPG nuclear and, say, assign a value of 3 moderate to capacity risk, at that moment when you are doing that, your subjective assessment of that risk for that company?

DR. ROBERTS: Our assessment based on a review of the evidence that we cite in the report.

MR. PENNY: Okay. But there is no formula or corporate finance principle that drives you to that. That is an assessment of the evidence?

DR. ROBERTS: Well, the principle is that we want to adjust the capital structure where the risk is - you've already indicated -- but that point is a matter of assessment based on the evidence, yes.

MR. PENNY: I think I have asked some others about this, but you would agree that is a question of informed judgment?

DR. ROBERTS: Yes.

MR. PENNY: Okay. One thing I didn't understand, is it an absolute assessment? Or is it a relative assessment?

So in other words, are you, at the moment that you assign a particular value to a particular category of risk for a particular -- in this case, OPG -- business, is that an assessment that you are making that is relative to something else? Or is it in your way of thinking, an absolute assessment? Done on a stand-alone basis?

DR. ROBERTS: You have to help me what you mean by "absolute". To me the word sort of suggested that low, moderate and high are relative terms, right?

MR. PENNY: Okay. I think we're probably on the same wavelength. So it is relative to something else, and in this case it was your generic assessment of transmission and distribution electric utilities? Do I have that right?

DR. ROBERTS: So are you asking me: Was this analysis conducted within the context of the utilities industry?

MR. PENNY: Yes.

DR. ROBERTS: The answer is yes.

MR. PENNY: Yes. And -- well, I'm asking you two questions, I guess. That is helpful, but then I am asking you a further, more detailed, more specific question, which is: When you actually assign -- when you are focussing on one category of those nine and looking at a particular company, are you making that assessment having regard to what you know about other utilities, I guess is what I'm asking you --

DR. ROBERTS: Well --

MR. PENNY: -- or are you making it more in an absolute sense that, for all time, OPG is this number?

DR. ROBERTS: As we tried to explain in our report, we make it a relative sense compared to other utilities.

MR. PENNY: That's what I thought. I just wanted to clarify that.

DR. ROBERTS: Then we go on to benchmark it against the different sectors, as I mentioned a moment ago.

MR. PENNY: All right.

DR. ROBERTS: In other words, since it was widely agreed in this hearing, and as you just walked me through it, that the lowest-risk sector is transmission, followed by distribution, followed by generation, and then two types of generation, we wanted to make sure that our model made sense, that it came up with that answer, that it was validated against that, and there is a section in the report which addresses that.

MR. PENNY: But, again, there is no -- when you are making that precise assessment for a given category of risk for a given company, there is, again, no mathematical theorem or formula that is telling you what that it is a 3, 4, or 2. That is a judgment that you make?

DR. ROBERTS: That is a qualitative judgment.

MR. PENNY: Okay. Would you agree with me that someone else using your framework, making other qualitative judgments, could go through the same exercise and come up with a different result that could still fall within some zone of reasonableness?

DR. ROBERTS: They could do that, or they could come up with one that didn't fall in that zone of reasonableness. It would depend on the person, but that's why we did the DSM benchmarking analysis against the sectors.

DR. KRYZANOWSKI: I think it is like any sort of estimate. Any estimate has error. There is always some estimation error.

MR. PENNY: Let me ask this. Would you agree with me that in evaluating business risk, both the probability of an adverse event occurring and its materiality are relevant considerations?

DR. ROBERTS: They are, assuming that you can come up with accurate estimates of those parameters.

MR. PENNY: Would you agree, I suppose subject to the same qualification, which doesn't trouble me, that for different utilities in different jurisdictions and in different circumstances, different categories of risk may be more or less material than others?

DR. ROBERTS: Yes, it says that in our report. For example, we talk demand risk. We say -- and Ms. McShane -- I think we agreed with Ms. McShane and even quoted from her in the evidence, that the probability of a major event that would cause demand risk in the utility would not be dispatched is low.

So even though we didn't put a numerical value on it, we did take the probability into account, as did Ms. McShane.

MR. PENNY: Yes, but I guess my point is you gave -- according to an answer you gave in an interrogatory, you gave all nine categories equal weight in coming up with the eventual number?

DR. ROBERTS: In terms of there being -- it being a qualitative model, that's correct.

DR. KRYZANOWSKI: I think --

MR. PENNY: Someone else might decide, based on the probability or materiality or some combination of the two, to assign different weights to those categories as opposed to weighting them equally as you have done?

DR. ROBERTS: Certainly. We might -- that's the case. Again, you have to remember the reason why we're doing this. It's not a numerical quantitative exercise, but just as you yourself raised it, I thought quite nicely as a way to avoid -- make sure that we remember to ask all of the right questions. In that sense, as sort of qualitative categories, we did, when we averaged them, use the same weights.

MR. PENNY: All right.

DR. KRYZANOWSKI: I think to be fair, I mean, in terms of our IR response, we said it was for presentation purposes, the equal weights.

MR. PENNY: Fair enough. But this is your evidence in this proceeding, so this isn't just a presentation. This is your evidence; right?

DR. ROBERTS: Sure.

MR. PENNY: Okay. Let me come at it from a slightly different way, that someone contemplating investing their money in an OPG-like entity may well not grant equal weight in terms of probability and materiality to all nine risk factors?

DR. ROBERTS: That's correct. But I would just say that this ties back to what we were talking about before, the article from the National Post.

We know that one of the problems with the sub-prime crisis was the failure of quantitative models to assess risks. So while -- and I would be happy -- as finance professors, we would be happy to agree that a more quantitative approach is, in many cases, to be preferred.

However, experience suggests that it can lead us to a false sense of security in trying to quantify things that are hard to quantify. I suggest that the sub-prime crisis and all of the mistakes that were made by analysts would be an example.

So would someone else come up with a different model? Quite possibly, but we're not saying that a model that is more qualitative is necessarily a worse model in this case.

DR. KRYZANOWSKI: I guess the other thing I would point out is even if you give different weights, someone else might also have different rankings. So the end result might be the same.

DR. ROBERTS: Our model is not -- far from perfect. It is the first time we have used it, but we're not going to apologize too much for it, because we feel it is a step forward and that a qualitative approach is what is needed in this case.

MR. PENNY: Please don't interpret anything I ask you as necessarily suggesting otherwise. I simply --

DR. ROBERTS: Thank you.

MR. PENNY: -- want to get some answers to my questions. I guess on this issue of -- well, let me just ask this.

You haven't -- in this model, you haven't analyzed which risks have, in fact, the biggest impact on revenue variability, as such, for OPG?

DR. ROBERTS: We assessed some of them as more important than others, in terms of the magnitude.

MR. PENNY: I.e., you have given them a three instead of a two?

DR. ROBERTS: Yes, that's right.

MR. PENNY: But that's the extent of it?

DR. ROBERTS: We don't weight them in that sense, no.

MR. PENNY: All right, thank you.

And I guess I will give you the open-ended question so you have an opportunity to explain it, but you've -- given what you have told me, that OPG Hydro is riskier than generic transmission and it's riskier than integrated utilities, OPG nuclear is even more risky than generic transmission or distribution or integrated, and this is a model that was designed for utilities, and you give OPG, with its, whatever, 60, 70 percent nuclear a 2.3 out of 5. I'm wondering who you're saving 2.4 to 2.5 for.

DR. ROBERTS: Well, that -- you would have to notice that in our table we are considering risk, and we're also considering factors that mitigate risk.

MR. PENNY: Yes.

DR. ROBERTS: And while the risks are higher in terms of the various factors, there has been a long discussion here, as we all know, about how -- what the risk of the company in capital structure might be. The undertaking that Ms. McShane has taken on, if all deferral accounts and risk mitigation were taken away, you would get much higher numbers.

But our analysis takes into account the mitigation, and because of the way the utilities are regulated in Canada, they are, on average, provided with many more opportunities to mitigate risk than in other countries, such as in the US. Therefore, we would come up -- we would be coming up with low numbers and we would expect that would be the case -- might be the case for other Canadian utilities, but we haven't done it yet.

MR. PENNY: So if I can summarize that, you are saying that it is being, in effect, using my words, reserved for those utilities that don't have risk mitigation available to them, upper end of the range?

DR. ROBERTS: -- bigger numbers, so that if we did that, that's where we might get those big numbers that you're looking for.

MR. PENNY: You will agree with me, though, that variance and deferral accounts, for example - I think you just said this - are a common feature of Canadian utilities?

DR. ROBERTS: Yes, that's correct.

MR. PENNY: And OPG, in asking for deferral and variance accounts in this case, is not acting in a manner that is -- that is radically dissimilar to other Canadian utilities?

DR. ROBERTS: In terms of those accounts in general, that's correct.

MR. PENNY: Okay.

DR. ROBERTS: Yes.

MR. PENNY: Okay.

MR. KAISER: Mr. Penny, would this be a convenient time for lunch?

MR. PENNY: I would be happy to break now, if that is convenient.

MR. KAISER: All right.

--- Luncheon recess taken at 12:31 p.m.

--- Upon resuming at 1:35 p.m.

MR. KAISER: Please be seated.

Mr. Penny.

MR. PENNY: Yes, thank you, Mr. Chairman.

Gentlemen, if you could turn to schedule 3.7, page 207 of your evidence, this, as I understand it, is the summary table that shows how the rankings worked from the use of your model, and then you layer on that your -- the information from your sample of transmission and distribution holding companies.

DR. ROBERTS: Yes.

MR. PENNY: Okay. You reference what the Alberta board did, and I take it that was in a generic hearing, those numbers that you've got beside EUB-2004, 33 and 37? Is that a finding of the EUB that you are using as a proxy for those?

DR. ROBERTS: Yes. It doesn't have a footnote there, but, yes, it is.

MR. PENNY: I guess the OEB 2006-2007, that looks like it is the distribution LDCs, or is that -- well, I guess the same anyway.

DR. ROBERTS: Yes, the distribution --

MR. PENNY: And transmission would be Hydro One, I guess?

DR. ROBERTS: Yes, that's right.

MR. PENNY: Okay. And you're taking some guidance, I take it, from those in terms of the relative rankings?

DR. ROBERTS: Yes. In terms of what boards have thought, regulators have thought to be appropriate.

MR. PENNY: Yes. Then under -- I guess you have the -- and then I want to go over to the "integrated" column. You list, I guess, Fortis BC, Maritime Electric and Newfoundland Power.

DR. ROBERTS: Yes. That's right.

MR. PENNY: Then at the bottom, still staying under "integrated", you've got: "Recommended by Doctors Kryzanowski and Roberts' prior evidence."

MR. ROBERTS: Yes.

MR. PENNY: Then you have a footnote at 176 that references Northwest Territories Power Corporation, 2007.

DR. ROBERTS: Mm-hmm. That's right.

MR. PENNY: So your recommendation was 42 percent?

DR. ROBERTS: Yes.

MR. PENNY: As I understand it, Northwest Territories Power was seeking 48.6 percent?

DR. ROBERTS: I think so, subject to check. It doesn't stick in my mind.

MR. PENNY: All right. In fact, Northwest Territories Power was allowed 48.6 percent, was it not, in that case?

DR. ROBERTS: They were allowed what they requested, yes.

MR. PENNY: All right. So I was curious why you put in your recommendation when you knew what they allowed.

DR. ROBERTS: Well, generally speaking, what we wanted to do is to give some two sets of benchmarks. One was what regulators had allowed, and another was what we had recommended, I guess, to show that we were being consistent with what we had recommended in other cases.

MR. PENNY: All right, but for Fortis BC, Maritime Electric and Newfoundland Power, you put down the allowed numbers, I assume, is what you're putting down.

DR. ROBERTS: Oh, I see what you mean, yes.

MR. PENNY: Am I right that Fortis BC, Maritime Electric and Newfoundland Power, those numbers are based on board -- on utility commission findings? Is that right?

DR. ROBERTS: Yes. Now, I'm sorry, I'm a little bit slow right after lunch.

We explain, in the text of our evidence, that we regard Northwest Territories Power Corporation as an above-average risk company and the reasons why.

MR. PENNY: Yes.

DR. ROBERTS: I believe it was for that reason that we didn't use it as one of the comparisons, because it wasn't really, in our opinion, a good example of more of a typical kind of integrated company, but we did include it as -- because we worked on that case, so we were a little inconsistent there, perhaps.

MR. PENNY: Then as I understand it -- just sticking with the Northwest Territories Power case for a second -- as I understand it, the Board also added a 50 percent -- sorry, 50 basis point upward adjustment to the ROE to compensate for another aspect of risk that that utility faced. Do I have that right?

DR. KRYZANOWSKI: I believe that's right. But that's the case where the cost of debt is pretty close to the cost of equity.

MR. PENNY: And I think what the Board said in that case if, I have it right, was that they were making this 50 basis point adjustment to ROE this time, but they wanted to see it in the risk analysis and therefore in the equity slice the next time. Is that right?

DR. ROBERTS: That sounds -- did you include that in your briefing book? Can we refer to it just to make sure it's accurate?

MR. PENNY: I think it is in the brief at page 51, if I have that right.

DR. ROBERTS: Tab 1?

MR. PENNY: Page 51, at the top. It's page -- it's tab 1, yes, page 51. It's page 47 of the decision, of which there is an excerpt here.

DR. ROBERTS: Okay.

MR. PENNY: If you look at the top of that page, it says:

"The Board notes Ms. McShane's view that the proposed capital structure would result in a DDD

rating for the corporation. The Board notes the
high cost of debt in NTPC's capital structure and
considers the 50 basis point upward adjustment
recommended by Ms. McShane is reasonable under
the circumstances to compensate for the
relatively high financial risk of the utility."

Right?

DR. ROBERTS: That confirms it, yes.

MR. PENNY: I think they go on to say they would prefer to see that dealt with in the capital structure the next time around.

DR. ROBERTS: Yes.

DR. KRYZANOWSKI: Right.

DR. ROBERTS: Yes, that's right.

MR. PENNY: All right, thank you.

In the context of operational risk, which is one of your risk categories, you make the point that production shortfalls, due to factors under the control of management, do not constitute a relevant business risk.

DR. ROBERTS: Yes.

MR. PENNY: And at page 36 of your evidence, you decided to compare unit capacity factors supplied by OPG in an answer to an interrogatory against a number of 91 percent capacity factor that you say, on page 36, was provided by DBRS.

DR. ROBERTS: That's right.

MR. PENNY: Do you see that?

DR. ROBERTS: Yes.

MR. PENNY: How did you get that from DBRS?

DR. ROBERTS: I'm just looking at page 36. I guess there isn't a citation. I believe it was from the DBRS report of 2005, but it's not footnoted. That is my recollection, but it may have been from another DBRS report.

MR. PENNY: That's at tab 11 of my brief.

DR. ROBERTS: I am not sure. I'm sorry. I just can't find it.

MR. PENNY: All right.

DR. ROBERTS: 2007, that's the 2007 report. Is the 2005 report there as well?

MR. PENNY: It is in the evidence, but I didn't excerpt it in this brief.

DR. ROBERTS: If we could find that, I could maybe take a look.

MR. PENNY: Well, I don't want to get bogged down too much in this, but let's take one second and see. We will take one second and see if we can find it.

DR. ROBERTS: Okay.

MR. PENNY: Perhaps what you could do is, because I don't want to get bogged down in this, if you wouldn't mind undertaking to provide the reference.

DR. ROBERTS: Certainly.

MR. PENNY: Thank you. Ms. Campbell?

MR. KAISER: Do you have a number for that?

MR. PENNY: Can we get a number for that?

MS. CAMPBELL: Well, of course you can.

MR. PENNY: Professor --

MS. CAMPBELL: That'll be the first undertaking of the day. That is J13.1.

MR. PENNY: Thank you.

MS. CAMPBELL: Provide the source of the 91 percent capacity factor referred to --

MR. PENNY: Yes.

MS. CAMPBELL: -- on page 36 of the Kryzanowski-Roberts report.

UNDERTAKING NO. J13.1: TO PROVIDE THE SOURCE OF THE 91 PERCENT CAPACITY FACTOR REFERRED TO ON PAGE 36 OF KRYZANOWSKI-ROBERTS REPORT.

MR. PENNY: Do you know what that benchmark was based on?

DR. ROBERTS: No. We took it from a source that we're going to provide you as being representative of best practices in the industry.

MR. PENNY: Do you know whether it was based on US data or Canadian data?

DR. ROBERTS: No. No. If it's a nuclear, it must have been -- it's highly likely it was based on international data.

MR. PENNY: Right. But you don't know sitting here today?

DR. ROBERTS: No, I don't know that.

MR. PENNY: Okay. Do you know whether it was CANDUs or light water plants?

DR. ROBERTS: No. I don't know that.

MR. PENNY: All right. Did you conduct any analysis of the data to determine the contributing factors to why the alleged benchmark capacity factor was 91 percent?

DR. ROBERTS: No. What we did is we looked at that data. We looked at the data on International Atomic Energy website, which is cited on page 37, along with the OPG data, but we did not conduct any independent engineering studies of it on our own.

MR. PENNY: Like, for example, the size of the units or the type of technology?

DR. ROBERTS: We did not examine that.

MR. PENNY: All right. And you didn't look -- and you didn't look at, say, something like the standard deviation around the 91 percent to determine whether each particular plant that was in the survey was consistently close to 91 percent, or whether certain plants were above in some years and below in others?

DR. ROBERTS: Well, we did look at the individual plants, as it explains on page 37. There is a table there.

MR. PENNY: Sorry. Just so we're clear, I was asking you not about the OPG plants, but about the plants in the database that you -- that underpin this 91 percent capacity.

DR. ROBERTS: No. We conducted no independent study on the database which underpins that 91 percent.

MR. PENNY: All right. You haven't conducted, similarly, any investigation or analysis of OPG's operations to determine the reasons why OPG's capacity factors are what they are?

DR. ROBERTS: We conducted a study of the data which is provided by OPG and listed on page 37.

MR. PENNY: Yes.

DR. ROBERTS: And we found that in 70 percent of the cases, the unit capability factor was below the 91 percent target. In other words, in three -- 30 percent of the cases, it was above.

MR. PENNY: Not my question.

DR. ROBERTS: So while that would have been a good number, 30 percent, batting 300 in baseball, even as non-nuclear experts we reached the conclusion that that 300 batting average was not a particularly impressive score, and that is the basis for this analysis.

MR. PENNY: That is not my question, sir.

My question was: You conducted no investigation or analysis of OPG's numbers to determine the reasons why OPG's capacity factors are what they are?

DR. ROBERTS: That's correct. We did not.

MR. PENNY: All right. And so you simply assumed that all the difference between this 91 percent benchmark and OPG's numbers were attributable to management?

DR. ROBERTS: We didn't make any assumption about that. We --

MR. PENNY: Well, sir, you say:

"These data strongly suggest that production shortfalls attributable to management issues and not constituting a risk to be recognized in regulation were a major concern."

You have told me you don't know where that 91 percent came from, so it has to be that you assumed that the difference of OPG between that and the 91 percent was attributable to management.

DR. ROBERTS: When you are ready, I will be pleased to explain.

MR. PENNY: Please do.

DR. ROBERTS: Thank you.

MR. PENNY: But I hope you are going to answer my question.

DR. ROBERTS: I will attempt to. If not, I am sure you will point it out to me. Without making a big deal out of it, we did conduct an independent study. However, we looked at two sets of numbers. We looked at the 91 percent benchmark I am going to provide the reference for from DBRS. We looked at the data which OPG provided.

We had no reason to believe that there was any problem with that data or that as it in some way misleading, so we accepted it at face value and we determined that 30 percent of the cases, the number that OPG reported was at or above the level of that international benchmark, which we drew from DBRS. That meant in 70 percent of the cases it was below.

Without making any assumption, we didn't have to assume that all of that 70 percent was explained by management. We said, Here's a target of 91 percent and you're below it 70 percent of the time. Even allowing for factors that we hadn't investigated, because we're not engineering experts, we reached the conclusion that that big discrepancy, 30 versus 70, suggested that -- at least a large part of it, strongly suggests that management had fallen below the target, and that's how we reached that conclusion.

MR. PENNY: Yes, all right.

DR. KRYZANOWSKI: I think the important words in that sentence are "strongly suggest", so it is pretty hard to argue that it means that we attribute all of it to management.

MR. KAISER: Well, what are we to interpret from that? If it's not all of it, what portion of it is it, or do you know?

DR. ROBERTS: Mr. Chairman, we don't have information to put a number on it. We're just saying that a very important portion of it was attributable to management based on the limited information we have just described.

MR. PENNY: Maybe you could go back to -- sorry, Mr. Chairman.

MR. KAISER: Thank you.

MR. PENNY: Maybe you could go back to the DBRS report for a minute, which was tab 11.

DR. ROBERTS: The '07 report?

MR. PENNY: Yes. November 30th, 2007.

DR. ROBERTS: Yes, we have it.

MR. PENNY: At page 12, I think it is -- which is I think about the third-last page, there is a generation portfolio notation there. Do you have that?

DR. ROBERTS: Yes.

MR. PENNY: You see that they've got the three nuclear stations, Darlington, Pickering A, Pickering B?

DR. ROBERTS: Yes.

MR. PENNY: And you will agree with me that Darlington is by far the largest, in terms of percent of total capacity; right? It is 16 percent. Pickering A is 5 percent and Pickering B is 9 percent?

DR. ROBERTS: Yes. That's what it shows there.

MR. PENNY: Okay. And if you would look across at Darlington, the numbers here indicate that Darlington, from 2004 to nine months in -- to September 2007, ranged from 88 percent to 91 percent?

DR. ROBERTS: Correct.

MR. PENNY: Then it is the Pickering A and Pickering B numbers that are significantly off the 91 percent; right?

DR. ROBERTS: Yes. And that's a similar conclusion that you might reach by looking at what's on page 37 of our evidence.

MR. PENNY: And you are aware, sir, that, for example, Pickering A is the oldest station? Indeed, it is one of the first CANDUs ever built?

DR. ROBERTS: Right, right.

MR. PENNY: Are you aware of that?

DR. ROBERTS: Yes.

MR. PENNY: And are you aware that it's OPG's evidence in this case that while improvements in Pickering A and B are possible, they will never perform to the level of Darlington, because of the age and the technology involved?

DR. ROBERTS: I take that subject to check, yes.

MR. PENNY: I guess the numbers themselves, I will put to you, are rather suggestive of the fact that the difference is significantly driven by the difference in technologies, because they're so obviously limited to the plants involved. In other words, is there a reason why the management -- well, I mean, the evidence actually is that there is a central management of this operation, as well as plant managers.

So -- but you're not suggesting that the manager of Darlington -- do you think that the manager of Darlington is that much better than the manager of Pickering A?

DR. ROBERTS: I didn't reach any conclusion about the individual managers of Pickering A versus Darlington.

MR. PENNY: All right. Let's move to a different topic, but close by in the evidence. If you would flip over to page 39.

DR. ROBERTS: Hmm-hmm.

DR. ROBERTS: Okay.

MR. PENNY: This is under the heading of "regulatory risk. I simply just wanted to confirm something and then just -- and clarify something.

You talk about regulatory risk and you make the observation that the difference is that the stakes are higher due to the higher operational risk of nuclear generation, and then you say:

"On this point we agree with Standard & Poor's, which states --"

And then you quote:

"'OPG is likely to be the first and only generator to fall under OEB's regulatory oversight. It remains to be seen whether the capital structure and returns allowed by the regulator post-2008 will reflect the much --'"

I think there is a word missing there, and you can check this if you like, but I think it says "much higher".

DR. ROBERTS: Yes, I am sure you're right.

MR. PENNY: "-- operating costs associated with electricity generation," et cetera.

DR. ROBERTS: Right.

MR. PENNY: Okay.

So subject to that change, you agree with that proposition?

DR. ROBERTS: I do.

MR. PENNY: Okay. Then let's leave capital structure for a moment and talk about the return on equity.

First of all, at a very high level, as I understand it, what you do is you take a risk-free rate and then you try and assess the market risk premium for the average Canadian stock, and then you determine how risky the average Canadian utility is in relation to the average Canadian stock and adjust for that. Is that, simplistically --

DR. KRYZANOWSKI: Not totally correct.

MR. PENNY: Okay. You tell me, but try to keep it at a high level because I am just talking concept here.

DR. KRYZANOWSKI: We take a risk-free rate.

MR. PENNY: Yes.

DR. KRYZANOWSKI: We take the market rate. Difference is going to be a market equity risk premium.

MR. PENNY: Yes.

DR. KRYZANOWSKI: Then we assess what the relative risk is of what we call an average risk utility.

MR. PENNY: Yes.

DR. KRYZANOWSKI: And we use both a beta sort of sensitivity method, and we also use a total risk method.

MR. PENNY: All right. I was attempting to say what you just said, so thank you for that.

Then that gives you, as I understand it, what you call the bare-bones cost of equity.

DR. KRYZANOWSKI: That is correct.

MR. PENNY: Then you add to that an allowance for flotation costs and financing flexibility?

DR. KRYZANOWSKI: Right, because basically it appears to be normal practice.

MR. PENNY: And the risk-free rate, that's something that's obtained from an objective and transparent source. Am I right? There is typically little controversy around that.

DR. KRYZANOWSKI: In terms of these types of hearings?

MR. PENNY: Yes.

DR. KRYZANOWSKI: Yes.

MR. PENNY: All right.

DR. KRYZANOWSKI: I guess, you say "objective", I mean it is the opinion of a group of forecasters.

MR. PENNY: I meant objective in the sense that it is publicly available. There are no complex formulas or machinations that need to be gone through. You buy the service, and there it is.

DR. KRYZANOWSKI: Yes.

MR. PENNY: Okay. Then page -- but as I understand your evidence, in contrast, the market equity risk premium does require expertise, experience and judgment to calculate.

DR. KRYZANOWSKI: Absolutely, because it's a going-forward type of estimate.

MR. PENNY: Right. And I think you say that the forward-looking -- that forward-looking risk premiums or risk premia -- to the Latin scholars -- are difficult to observe and depend on future estimates that can be subject to considerable estimation error and bias.

DR. KRYZANOWSKI: They are definitely subject to estimation error and bias, depending on the method used.

MR. PENNY: Yes, I therefore take it that it is not obvious how to do this, to ensure you've got it right, because there's the two of you with Ph.D.s and you spent 20 pages explaining this, so it is not obvious.

It requires estimation and it requires what, to a layperson at least, would be relatively complex methodology.

DR. KRYZANOWSKI: It's not obvious that it is straightforward. But in terms of the 20 pages, I mean that's for a different audience. Right? If I was writing for Gordon, I wouldn't have to use 20 pages.

MR. PENNY: Precisely my point. Thank you.

You will agree with me that it, therefore, requires considerable analysis and informed judgment to come up with what you think is the right market equity risk premium?

DR. KRYZANOWSKI: Definitely requires a fair amount of analysis. There is some informed judgment, but if there's estimation error, then you can always give a conservative estimate.

MR. PENNY: All right. But even on the question of estimation error, people disagree about what causes and doesn't cause, and how to measure that, don't they?

DR. KRYZANOWSKI: Well, there's -- if you look academic literature there tends to be less agreement -- less disagreement over time. There's some disagreement, in terms of how much the equity risk premium has decreased.

MR. PENNY: Mm-hmm. And would you agree that the third step, or I guess the second adjustment to the risk-free rate, what I will just call the beta adjustment for simplicity, but I appreciate that you say there is the two aspects to it, you also there have to make an estimation?

DR. KRYZANOWSKI: That is correct.

MR. PENNY: That, too, involves analysis and informed judgment?

DR. KRYZANOWSKI: Well, remember that if you estimate single betas and then use a grouping procedure, moving to an average, that tends to reduce estimation errors. So there are sort of standard procedures that people use in the literature for estimating betas.

MR. PENNY: Yes. But do you agree that nevertheless, the determination of what you view as the right beta in a particular context requires the use of informed judgment?

DR. KRYZANOWSKI: Implementing any estimation method requires some informed judgment.

MR. PENNY: Including this one?

DR. KRYZANOWSKI: Including this one.

MR. PENNY: Thank you. I know you're critical of the discounted cash flow and the comparable earnings methods, but you will agree with me that the CAPM approach or the equity risk premium approach is not perfect either, is it?

DR. KRYZANOWSKI: It's not perfect, but it's quite a bit -- it's a lot better than the comparable earnings method, and the discounted cash flow approach is good at the aggregate level.

MR. PENNY: Professor Roberts, I believe you last testified before this Board in 1997?

DR. ROBERTS: Probably that's right, yes.

MR. PENNY: And at that time, you weren't testifying for an intervenor, as you are now, but you were testifying on behalf of the Board Staff; is that right?

DR. ROBERTS: I was a Board Staff expert, that's correct.

MR. PENNY: And to determine -- you were testifying in

a Consumers Gas case on the cost of equity?
DR. ROBERTS: That's correct.
MR. PENNY: And to determine the recommended return on common equity for Consumers Gas, you employed a comparable earnings test?
DR. ROBERTS: I did.
MR. PENNY: A discounted cash flow test?
DR. ROBERTS: Yes. It was one of the errors of my youth, and I have since corrected it.
[Laughter]
MR. PENNY: And, and -- but I will give you this -- and the equity risk premium test.
DR. ROBERTS: I did use the equity risk premium test as well.
MR. PENNY: I was looking at your evidence last night, -- if you can believe it -- and you weighted at that time comparable earnings, 45 percent, earnings -- equity risk premium at 45 percent and DCF method at 10 percent. Does that sound right?
DR. ROBERTS: It sounds right. I haven't looked at it recently.
MR. PENNY: Apropos of your comment a moment ago that you have moved on, I take it that the implication of that is that in a decade from now, some other person will be sitting there -- perhaps you -- saying that: Oh, well, the CAPM method wasn't really the best way to do it either.
DR. ROBERTS: It is certainly possible. We have to benchmark it, and in our report we cite a well-known

academic article by two American academics at -- Campbell and Harvey, that was published in, I believe, in the Journal of Financial Economics, a top journal, where they surveyed the managers of Fortune 500 companies in the US and Canada and asked them what they believe were the best practices methods in a variety of areas of corporate finance.

One of them was the cost of capital -- what we're doing here -- and the answer was that those companies regarded the cap asset pricing model as the best practices. So while it is true that ten years from now, something may supersede it, it is our understanding, based on the research and textbooks that we work on, that it is the best practices today.

MR. PENNY: All right. Then turning to -- I just wanted to ask a few questions about the market equity risk premium.

It's intended to reflect the equity investor's assessment of the return differential between a risk-free investment and an available investment opportunity that would be required to induce the investor to make the equity investment.

Is that conceptually right?

DR. KRYZANOWSKI: If you're talking about the market equity risk premium --

MR. PENNY: Yes.

DR. KRYZANOWSKI: -- it's the difference between investing and, say, a market proxy and the risk-free rate.

MR. PENNY: And your --

DR. KRYZANOWSKI: But you have to be a little bit careful, because there is a difference between expectations and realized values.

MR. PENNY: Fair enough. You're talking realized values, are you, or are you talking --

DR. KRYZANOWSKI: Well, when you go forward, you're talking about expectations.

MR. PENNY: Yes. When you're looking at historical data, you're talking about realized values?

DR. KRYZANOWSKI: You look at realized values in terms of getting an estimate going forward.

MR. PENNY: Yes. And your market equity risk premium is 5 percent?

DR. KRYZANOWSKI: That's a recommended --

MR. PENNY: That's what I mean. That's what you're recommending?

DR. KRYZANOWSKI: Yes.

MR. PENNY: And your risk-free rate, I think, in accordance with the update, is 4.1 percent for 2008 and 4.4 percent for 2009, am I right?

DR. ROBERTS: I believe that's correct.

MR. PENNY: So if you add the risk-free rate and your market equity risk premium of five, this is before the third step, I appreciate, but you get 9.1 percent for 2008 and 9.4 percent for 2009?

DR. ROBERTS: I'm trying to find that. Mr. Penny, just to clarify, you're saying if we take the market risk premium and add the recommended risk-free rate, we get those numbers?

MR. PENNY: Yes.

DR. ROBERTS: So it would be 9.1 percent for 2008.

MR. PENNY: Yes.

DR. ROBERTS: And 9.4 percent for 2009.

DR. KRYZANOWSKI: For the market, yes.

DR. ROBERTS: To find out what the predicted return for the market would be?

MR. PENNY: This is without beta and without financing flexibility. I just wanted to make sure we were in agreement on those numbers.

DR. KRYZANOWSKI: I should point out it is quite a bit higher than the objective consensus of investors.

MR. PENNY: I wanted you to turn, if you would, to schedule 4.3 in your evidence. That's at page 211.

This has, you say, various estimates of historical annual risk premiums of stocks over risk-free rates for various time periods.

I just wanted you to look at -- first, maybe we just stick with arithmetic mean for the sake of the discussion, again, just to keep it manageable. But the stock returns under the first column are showing a relatively constant return for all but the last time series of around 11.2 to 11.6 percent; right?

DR. KRYZANOWSKI: Hmm-hmm. That's correct.

MR. PENNY: And then if we go -- look under the next column, "long Canada returns", those are not relatively constant, but, in fact, are steadily increasing as you shorten the time series?

DR. KRYZANOWSKI: Right, which is a good example of mean reversion for stock, and mean aversion for bonds.

MR. PENNY: And, in fact, using the arithmetic mean, they go from 6.46 percent to 10.47 percent as you move up more recently in the time series?

DR. KRYZANOWSKI: Right.

MR. PENNY: But whereas today, you are forecasting a risk-free rate of about 4 percent?

DR. KRYZANOWSKI: Remember that is in terms of an interest rate. These are in terms of returns.

MR. PENNY: Yes.

DR. KRYZANOWSKI: And, second, it is -- it's a different environment.

MR. PENNY: Well, fair enough, but --

DR. KRYZANOWSKI: No, no, but, I mean, if you look at the expectations of market professionals in terms of stocks, they're not predicting 11 or 13 percent going forward. So it's also consistent with that.

MR. PENNY: Hmm-hmm. I guess my point is simply that we've had relatively consistent stock returns, but increasing historically long Canada returns. But you're not necessarily forecasting long Canada returns anywhere near these numbers, are you?

DR. KRYZANOWSKI: No. And we're not forecasting stock returns anywhere near that, either. So, basically, remember, these are realized values for both stocks and bonds, and what we're trying to do is make a forward-looking forecast.

MR. PENNY: Well, I think you will also agree with me that your 9.1 percent and 9.4 percent, they're considerably lower than the 11.64 to 11.2 that we're seeing in the principal historical series here, too?

DR. KRYZANOWSKI: That's true, but I think we're in good company because, again, if you look at the Mercer survey or the Watson Wyatt survey, in fact, our forecast is somewhat high, in terms of other professionals looking forward.

MR. PENNY: Well, Dr. Kryzanowski, I am going to put to you that your estimated market equity risk premium is downwardly-biassed, since you have not given sufficient recognition to market equity risk premium increases resulting from lower anticipated bond market returns.

DR. KRYZANOWSKI: I would respectfully disagree. I don't think there is any bias. In fact, if you look at the risk premia, you concentrated on the stock return being constant and the long Canada returns increasing.

If you look at the risk premia, you see a decrease over the period and, if anything, instead of reflecting that decrease, we've chosen a market equity risk premium of 5 percent.

MR. PENNY: Would you turn to tab 1 of this large brief, please?

DR. KRYZANOWSKI: Sure.

MR. PENNY: Turn up page 47. This is an excerpt from a decision of the Public Utilities Board of Northwest Territories. If you would look at page 49 of the brief, page 45 of the decision, you will see that -- I will try to shorten this. I will try to shorten this a bit, but the Board -- you will see it says:

> "The Board notes NTPC's submission that the risk premium looking forward should be higher than historic values when bond market returns are expected to be lower."

Then this there is a quote from their argument:

> "Ms. McShane's rebuttal evidence pointed out that Drs. Kryzanowski and Roberts acknowledge that there has been no material change in the equity market return. If equity market returns are approximately the same, but the bond market returns are expected to be lower, then it follows that the risk premium looking forward should be higher than the historical values."

Then it goes on to say:

> "The Board considers Drs. Kryzanowski and Roberts' estimated market equity risk premium to be downwardly-biassed since the witnesses do not appear to have given recognition to market equity risk premium increases resulting from lower prospective bond market returns compared to the historic period."

You are the same Drs. Kryzanowski and Roberts, are you not?

DR. KRYZANOWSKI: We are, but I would like to point out in other hearings boards have not made that particular decision.

MR. PENNY: Do you accept that the fair return standard, as articulated by the Supreme Court of Canada, requires that the utility shall 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?

DR. KRYZANOWSKI: I accept that, but I would like to point out it is not captured by using the comparable earnings type of test.

MR. PENNY: If you would like to turn in volume 2 for a moment, please, which is the smaller stapled brief, and turn up page 11. This is an updated schedule that was provided in answer to an interrogatory -- or an undertaking by Ms. McShane. Do you have that, page 11?

DR. ROBERTS: Yes, we do.

MR. PENNY: I appreciate the print is small, but we have returns listed for electric utilities, gas distributors, gas pipelines, and if you look at the 2008 column, you will agree with me that the returns that are listed there are all higher by a significant margin than your 7.35 percent for 2008 and your 7.4 percent for 2009?

DR. ROBERTS: Yes, we agree, and we also note that they're all considerably lower than the return recommended by Ms. McShane.

MR. PENNY: And you will agree with me that -- well, first of all, will you agree with me that Nova Scotia Power is the only one of these entities that is not subject to the formula ROE adjustment along the NEB model-type lines?

DR. KRYZANOWSKI: That appears to be correct.

DR. ROBERTS: It appears to be correct, yes.

MR. PENNY: All right. Thank you.

You will also agree with me that there are no nuclear generation operations reflected on any utility on that list?

DR. KRYZANOWSKI: Yes.

DR. ROBERTS: Yes.

MR. PENNY: And these are all entities that you agree are lower-risk than OPG's prescribed assets?

DR. ROBERTS: That's correct.

DR. KRYZANOWSKI: I think you have to put it in context in terms of the approach we use. We use a similar approach to Ms. McShane, in terms of looking at the average risk utility, in terms of the ROE. And any changes in risk or differences in risk are picked up by the capital structure.

MR. PENNY: Well, I appreciate that's your model, but on that theory, all the utilities should have the same ROE, right?

DR. ROBERTS: Well, we're just pointing out that, without going into a big discussion here, that there are two approaches. One approach is to adjust the risk to it through the capital structure, as my colleague just pointed out, as has been taken in Alberta and historically in Ontario.

But as I am sure you are well aware, there is another approach, such as the one in BC, where they adjust both the capital structure and the ROE.

MR. PENNY: Yes.

DR. ROBERTS: Since some of the companies are in BC, there is a mixture of the two approaches here.

MR. PENNY: Fair enough.

Thank you, gentlemen, those are all of my questions.

MR. KAISER: Thank you.

Any questions?

QUESTIONS FROM THE BOARD:

MR. RUPERT: I have one.

Doctors Roberts and Kryzanowski, I just have one question about this nuclear operating risk issue, which has come up pretty well consistently throughout this hearing in one form or another.

I want to ask about the question Mr. Penny was asking you about and that your report refers to, on -- I will put it this way -- apportioning the blame between management and the machine.

I am trying to understand the time horizon one would use in making that assessment. If I go way back, somebody decided to build these nuclear plants. May not be the current management, but somebody in the company.

If you shake the timeframe down to years or months or weeks, clearly lots can happen within the short timeframe,

TAB 4

EB-2007-0905

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain of its generating facilities.

BEFORE: Gordon Kaiser
Presiding Member & Vice Chair

Cynthia Chaplin
Member

Bill Rupert
Member

DECISION WITH REASONS

NOVEMBER 3, 2008

any other regulated Ontario energy utility, thereby recognizing the higher risk of OPG. The Board notes that this deemed capital structure will be applied to the rate base which is net of the specific treatment to be applied to the nuclear liabilities related to Pickering and Darlington (which is discussed in Chapter 5).

8.4 Return on Equity

8.4.1 Introduction

Ms. McShane used three tests: the Equity Risk Premium ("ERP") test, the Discounted Cashflow ("DCF") model test and the Comparable Earnings ("CE") test. For the ERP test, she used three approaches:

- Capital Asset Pricing Model ("CAPM")
- Historical utility risk premium test
- Discounted Cash Flow ("DCF") risk premium test

Although Ms. McShane updated her estimates of the various tests in April 2008, the result was no change in the aggregate ROE recommendation: in her view, the lower government interest rate is partially offset by a higher risk premium which is reflected in a higher spread between government bonds and long-term A-rated utility bonds.

Pollution Probe submitted that the Board should prefer and accept the recommendations of Drs. Kryzanowski and Roberts. They used four methods to estimate the market equity risk premium: the Equity Risk Premium (including CAPM) methodology and three other methods to support the "directional conservatism" of the estimate derived from the ERP method. Pollution Probe noted that OPG acknowledged that this was now the dominant methodology used for regulated energy utilities in Canada.

CCC submitted that the Board should prefer the testimony of Dr. Booth to that of Ms. McShane. Dr. Booth estimated that OPG will have sufficient financial flexibility to access capital markets on reasonable terms with an ROE of 7.75% and an equity ratio of 40%. Dr. Booth relied on a CAPM risk premium model and a two-factor model, with the CAPM estimate based on an historic average market risk premium adjusted for the

8.4.5 Should there be separate costs of capital for regulated nuclear and regulated hydroelectric?

GEC-Pembina-OSEA took the position that OPG should recognize the higher risks of the nuclear business in its capital and OM&A expenditure decisions. GEC-Pembina-OSEA sponsored the evidence of Mr. Paul Chernick on this issue. GEC-Pembina-OSEA concluded:

> The Board should select an acceptable combined cost of capital (with the deferral accounts it finds acceptable in place) and then adjust the nuclear division equity ratio and RoE upward and make a corresponding balancing downward adjustment to the hydraulic division values in accord with Ms. McShane's estimates.[123]

GEC-Pembina-OSEA submitted if the Board does not set a separate cost of capital for each division, then the Board should direct OPG to use project-specific discount rates to reflect the relative risk level. GEC-Pembina-OSEA also suggested that in a future proceeding it might be appropriate to consider Mr. Chernick's proposal that deferral accounts be minimized, that the risk be reflected in the cost of capital, and that the added revenue be segregated to mitigate those risks if they arise.

Pollution Probe submitted:

> For purposes of cost allocation and rate design, separate and distinct costs-of-capital should be used since: 1) the nuclear assets are riskier than the hydro assets; and 2) OPG is already proposing different charges per MWh for its nuclear and hydro-electric assets [due to separate costs of production].[124]

Pollution Probe noted OPG's testimony that it did not object to this approach in principle, although it expressed concern as to whether such an approach was pragmatic in terms of the necessary calculations. Pollution Probe was of the view that the Board has the necessary evidence for such an approach and submitted that the evidence of Drs. Kryzanowski and Roberts should be accepted as they did determine separate capital structures for nuclear and hydroelectric as part of their analysis.

[123] GEC-Pembina-OSEA Argument, p. 7

[124] Pollution Probe Argument, p. 2.

SEC submitted that there would be value in setting separate capital structures in terms of reviewing investment decisions, but noted that the nuclear costs are not "real" in any event because the liabilities were shifted from OPG when it was created. SEC concluded that whether or not the Board sets separate structures,

> ...it should direct OPG to maintain records of the relative costs of production and investment using separate equity ratios, and to carry out business case and similar forward-looking expenditure analyses using those technology-specific equity ratios.[125]

SEC submitted that the same ROE should apply to both, because the difference in risk is appropriately captured through the equity ratio.

CME submitted that there was no need to set separate capital structures for the nuclear and regulated hydroelectric when they are operated by a single business entity.

OPG responded that alleged benefits of technology-specific cost of capital either do not exist or are insignificant. For example, there is no evidence that a higher nuclear payment amount would impact operating decisions, and OPG already has a strong incentive to meet its production targets. Further, OPG's project specific risk analysis provides more rigour than a technology-specific discount rate would.

Board Findings

Although the regulated hydroelectric and regulated nuclear businesses are held by the same entity, in many respects they are operated quite separately. The rate base is separate; the production forecasts, capital budgets and OM&A forecasts have been established separately; the corporate cost allocation is done separately; and the payments are set separately. The two businesses also face different risks. The Board finds that there may be merit in establishing separate capital structures for the two businesses. It would enhance transparency and more accurately match costs with the payment amounts.

However, the Board also finds that the evidence in this proceeding is not sufficiently robust to set separate parameters at this time. Drs. Kryzanowski and Roberts developed separate estimates, but concluded with a combined recommendation. Ms.

[125] SEC Argument, p. 9.

McShane developed separate estimates, but cautioned that she was not as confident with the analytical results because they had been derived from working backwards.

The Board concludes that this is an approach worthy of further investigation which will be explored in OPG's next proceeding. In examining whether to set separate costs of capital, the Board intends only to examine whether separate capital structures should be set for the regulated hydroelectric and nuclear businesses. The Board expects that the same ROE would be applicable to both types of generation. This is consistent with the general approach of setting a benchmark ROE and recognizing risk differences in the capital structure.

The Board recognizes that this approach will not alter the overall cost of capital for OPG's prescribed facilities. However, in all other significant respects the specific costs or the hydroelectric and nuclear businesses are used to derive the specific payments for each type of generation. Specific and separate costs of capital for hydroelectric and nuclear would be consistent with the separate nature of these businesses and would provide a more transparent link between the payment amounts for each type of generation and the underlying costs.

8.4.6 Should the Board adopt a formula to determine the ROE in future?

OPG proposed that the Board adopt an ROE adjustment formula for purposes of determining OPG's ROE in future proceedings. Specifically, OPG proposed adoption of the existing ROE adjustment formula outlined in the Board's report on cost of capital and 2nd generation incentive regulation for Ontario's electricity distributors.[126] That formula results in a 75 basis point change in ROE for every one hundred basis point change in the 30-year Long Canada Bond forecast.

OPG noted that it would seek a review of the formula returns if its business risk or access to capital changed materially and submitted that the adoption of a formula should not preclude it or another party from seeking a review. SEC supported the use of Board's formula approach to adjusting the ROE for years after 2009. CME also submitted that the formula approach was reasonable.

[126] *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, December 20, 2006.

TAB 5

OPG Interrogatory No. 25 to Pollution Probe

Issue 3.3: Should the same capital structure and cost of capital be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure and/or cost of capital parameters are appropriate for each business?

Reference: Pollution Probe's Evidence (Exhibit M, Tab 10), Schedule 5.7, Drs. Kryzanowski's and Roberts' Recommended Capital Structures

Preamble:

Drs. Kryzanowski and Roberts provide some of their recommended capital structures in prior proceedings in which they have appeared. OPG would like to understand better how Drs. Kryzanowski and Roberts' recommendations have compared to the equity ratios adopted by regulators.

Question:

(a) Could Drs. Kryzanowski and Roberts please provide a table showing:
- (1) the recommended capital structure in each case in which Drs. Kryzanowski and Roberts have appeared since 2002;
- (2) the date of the testimony;
- (3) the client on whose behalf the testimony was prepared;
- (4) the regulatory jurisdiction;
- (5) the date of the decision;
- (6) the awarded capital structure.

Response:

(a) Drawn largely from the response to *OPG Interrogatory No. 28 to Pollution Probe* in EB-2007-0905, a chronological list of the cases in which Drs. Kryzanowski and Roberts appeared follows, which includes the requested information.

Nova Scotia Power

On behalf of the Province of Nova Scotia, they provided evidence and testified before the Nova Scotia Utility and Review Board in the matter of Nova Scotia

Power Inc. in 2002. Their recommended equity ratio was 35%. The Board awarded an equity ratio of 37.5% in 2002.

Hydro Quebec

They filed evidence and testified before the Régie de l'Enérgie du Quebec for the Fédération canadienne de l'entreprise indépendante ("FCEI") / Union des municipalities du Québec ("UMQ") & Option consommateurs ("OC") in the 2003 application of Hydro Quebec Distribution. Their recommended equity ratio was 34%. The Régie decision in 2003 awarded an equity ratio of 35%.

Alberta Generic Hearing 2003-4

On behalf of Consumers Group (i.e. Aboriginal communities, Alberta Association of Municipal Districts & Counties, Alberta Federation of REAs Ltd., Alberta Irrigation Projects Association, Alberta Urban Municipalities Association, Canadian Forest Products, Consumer Coalition of Alberta, Federation of Alberta Gas Co-ops Ltd. & Gas Alberta Inc., and Public Institutional Consumers of Alberta), they prepared testimony and testified in Generic Hearing No. 1271597 before the Alberta Energy and Utilities Board in 2003-2004. The following lists the common equity recommendations of Drs. Kryzanowski and Roberts by company along with the Board's decisions in 2004.

	2004 Board Approved Common Equity Ratios (%)	**Ratio Recommended by Drs. Kryzanowski and Roberts**
ATCO TFO	33.0	30.0
AltaLink	35.0	30.0
EPCOR TFO	35.0	30.0
NGTL	35.0	32.0
ATCO Electric DISCO	37.0	35.0
FortisAlberta (Aquila)	37.0	35.0
ATCO Gas	38.0	37.0
ENMAX DISCO	39.0	35.0
EPCOR DISCO	39.0	35.0
AltaGas	41.0	37.0
ATCO Pipelines	43.0	40.0

<u>Northwest Territories Power Corporation</u>

Drs. Kryzanowski and Roberts submitted evidence and testified before the Public Utilities Board of the Northwest Territories in the General Rate Application of Northwest Territories Power Corporation in 2007. The client was Hydro Communities (i.e. City of Yellowknife, the Town of Hay River and the Town of Fort Smith). Their recommended equity ratio was 42%. The Board awarded NTPC in 2007 deemed common equity ratios of 45.53% for 2006/7 and 48.59% for 2007/8.

<u>Ontario Power Generation</u>

More recently in 2008, Drs. Kryzanowski and Roberts submitted evidence and testified before the Ontario Energy Board in EB-2007-0905 on behalf of Pollution Probe regarding Ontario Power Generation's application. Their recommended equity ratio was 47%. The company requested an equity ratio of 57.5%. The Board awarded an equity thickness of 47% in 2008.

<u>Alberta Generic Hearing 2009</u>

Most recently, Drs. Kryzanowski and Roberts submitted evidence and testified before the Alberta Utilities Commission in the 2009 Generic Cost of Capital hearing on behalf of the Utilities Consumer Advocate ("UCA"). The UCA is a Government of Alberta entity whose mandate is "to ensure small consumers have the information, representation and protection they need to better equip them to make informed choices in Alberta's restructured electricity and natural gas markets" and to represent "the interests of small consumers in regulatory hearings". A table summarizing the requested information follows.

Date of Testimony: 2009 Generic Hearing. Client: Utilities Consumer Advocate. Jurisdiction: Alberta Utilities Commission. Date of Decision: 2009.			
K&R Recommended Equity Ratio %	Requested Equity Ratio	Utility	Awarded Capital Structure %
33	38	ATCO Electric TFO	36
33	38	AltaLink	36
30	40	ENMAX TFO	37
35	40	EPCOR TFO	37
42/34	43	ATCO Pipelines	45
35	40	ATCO Electric DISCO	39
35	44	ENMAX DISCO	41

35	44	EPCOR DISCO	41
34	40	ATCO Gas	39
35	44	FortisAlberta	41
40/37	46	AltaGas	43

Witness Panel Responsible: Dr. Lawrence Kryzanowski and Dr. Gordon Roberts

OPG Interrogatory No. 26 to Pollution Probe

Issue 3.3: Should the same capital structure and cost of capital be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure and/or cost of capital parameters are appropriate for each business?

Reference: Pollution Probe's Evidence (Exhibit M, Tab 10), Section 3.3.1.

Preamble:

On page 18, Drs. Kryzanowski and Roberts discuss their concerns with OPG's approach to reflecting project specific risks in cash flows. OPG wishes to understand whether Drs. Kryzanowski's and Roberts' concerns are already addressed in OPG's approach.

Question:

(a) Drs. Kryzanowski and Roberts state that there is a tendency of Monte Carlo simulations to underweight tail observations. Please provide the rationale for this conclusion.

(b) Do Drs. Kryzanowski and Roberts agree that if contemporaneous interrelationships (more commonly called correlation) are appropriately modeled that the above issue would be taken care of? If not, why not?

(c) Drs. Kryzanowski and Roberts argue that a Monte Carlo simulation should be done using the risk free rate to determine the appropriate discount rate. Please explain how this discount rate is then used.

(d) If the risk profile/uncertainty in an input variable changes, would that result in a different discount rate for the project?

(e) Would this not result in a different discount rate for each project? If not, why not?

Response:

(a) Dr. Kryzanowski has approximately 40 years of experience with the use of resampling techniques in research and investment/product analysis, including Monte Carlo simulations. He began with the development of a computer program for applying Monte Carlo simulation analysis to capital investment projects. An illustration of the practical

Response:

(a) – (c) Confirmed.

(d) The revised calculations are in the revised schedules attached as Attachments 1-4 to the response to *OPG Interrogatory No. 19 to Pollution Probe* (Exhibit M, Tab 10.15, Schedule 19, Attachments 1-4). The results of the calculations are labeled as "FFO-AT coverage ratio (times)" in each schedule. The values calculated for OPG Hydro for 2012 and 2011, respectively, are 2.86 and 2.85 times. While marginally below the AUC benchmark of 3 times, these ratios are not inconsistent with a bond rating in the A range. For OPG Nuclear the FFO-AT coverage ratios for 2012 and 2011, respectively, are 6.65 and 6.54 times. Both of these ratios far exceed the AUC benchmark of 3 times and are also not inconsistent with a bond rating in the A range. However, Drs. Kryzanowski and Roberts note the calculations employ a number of assumptions, and one unrealistic simplifying assumption is that the respective standalone costs of debt for OPG's Hydro assets and OPG's Nuclear assets are the same as when both sets of assets are combined.

Witness Panel Responsible: Dr. Lawrence Kryzanowski and Dr. Gordon Roberts

TAB 6

OPG Interrogatory No. 27 to Pollution Probe

Issue 3.3: **Should the same capital structure and cost of capital be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure and/or cost of capital parameters are appropriate for each business?**

Reference: **Pollution Probe's Evidence (Exhibit M, Tab 10), Schedule 5.7, Relating the benchmarks**

Preamble:

At page 65, Drs. Kryzanowski and Roberts state that "Schedule 5.7 shows that this business risk rating for OPG Nuclear exceeds the rating for OPG Hydro (1.8). It also signals that OPG Nuclear bears higher business risk than generic integrated companies (rated 1.5) or generic distribution utilities rated (1.4).

Question:

(a) Please confirm that the following table reflects the risk assessment of Drs. Kryzanowski and Roberts in EB-2007 -0905, and that the sole difference in their assessment in this case is that the OPG nuclear rating for deferral accounts should be 3.0 instead of 1.0 to reflect the fact the OEB determined that no fixed cost recovery should be allowed for OPG's regulated operations, and that the overall result is that OPG's Nuclear operations are rated as a 2.6 in the opinion of Drs. Kryzanowski and Roberts.

Market					
Competition	1	2	1.3	1	1
Credit	1	2	1.3	1	1
Operational					
Leverage	1	3	2.6	3	4
Technology	1	1	1.5	2	4
Capacity	1	1	2	3	3
Asset Retire/construct	1	1	1.5	2	3
Deferral Accounts	1	1	1	1	1
Regulatory					
Primary Regulatory	1	1	1	1	1
Environmental/Safety	1	1	1.5	2	3

OVERALL	1	1.4	1.5	1.8	2.3
Linear AVERAGE	1	1.44	1.52	1.77	2.33

(b) Drs. Kryzanowski and Roberts state that capital structures for regulated utilities are all established on a heuristic basis without reliance on a formula. Has the above scoring model been used to establish a utility capital structure or cost of capital for any regulated party? If so, please provide copies of the testimonies in which this scoring model was used.

(c) Drs. Kryzanowski and Roberts assert that OPG's nuclear operations rate a 2.6 on their scale of 1 to 5. They also state on page 40 that their scale of 1 to 5 represents risks for utilities. They also state that transmission utilities rate as 1.0 across all dimensions of their risk assessment as they are the least risky. Is there any Canadian utility that faces higher business risk than OPG's regulated nuclear component of its regulated operations? If so, please provide the utilities and the associated risk analysis using the 1 to 5 rating scale.

(d) Drs. Kryzanowski's and Roberts' scoring of each risk reflected in Schedule 5.1 of Page 86 reflect moderate risk as 3.0, moderate-high risk as 4.0, and presumably high risk as 5.0. Please provide the nuclear capital structure that would result if the linear average for all nine risk criteria resulted in an overall assessment that OPG's nuclear operations were moderately risky (e.g. 3.0), moderately-highly risky (4.0) and highly risky (5.0).

(e) In EB-2007-0905, OEB staff's witness defined "Risk Exposure" as a function of probability and cost (EB-2007-0905 page 13 of Ex. M Tab 1 Evidence of London Economics International, "Development of an Overall Framework to Determine an Appropriate Capital Structure and Return on Equity for Ontario Power Generation's Prescribed Facilities," by A.J. Goulding). Do Drs. Kryzanowski and Roberts agree with that definition?

(f) If Drs. Kryzanowski and Roberts do not agree with this definition, should factors whose score is identical among the comparators, e.g., primary regulation, be excluded from a comparative financial analysis? If no, please explain why not.

(g) If Drs. Kryzanowski and Roberts agree that the assessment of relative risk should be derived from the main drivers of absolute risk, should factors that are inconsequential (in terms of the probability and cost as defined by Goulding) be eliminated from the analysis in the table provided in part (a)?

(h) Please provide an adjusted risk assessment table similar to that summarized in Part a) that eliminates the factor "primary regulation" and the market factors of "competition/demand" and "credit".

Response:

(a) Confirmed.

(b) The framework was used in past evidence submitted by Drs. Kryzanowski and Roberts in EB-2007-0905 to support their recommendation of a 47% overall equity ratio for OPG. As noted on page 20 of their current pre-filed evidence, the Board adopted that recommendation. The framework was also used in their evidence in the Generic Cost of Capital Hearing leading to AUC Decision 2009-216. As requested, copies of Drs. Kryzanowski's and Roberts's pre-filed evidence for these two proceedings are attached as Attachments 1 and 2.

(c) Drs. Kryzanowski and Roberts have not conducted a detailed assessment of the business risk of all individual utilities in Canada. Consequently, they do not have the data to answer this question. However, they do note that there is no *a priori* reason to expect to find companies that will lie at every point on the rating scale if such an assessment were done.

(d) Please refer to the response to *OPG Interrogatory No. 12 to Pollution Probe* (Exhibit M, Tab 10.15, Schedule 12).

(e) On page 13 of the referenced report by Mr. Goulding, Drs. Kryzanowski and Roberts find the following passage that addresses probability and cost:

> Glyn A. Holten, in a 2004 paper, defines risk as being the "exposure to a proposition to which one is uncertain" (footnote deleted). 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.

Drs. Kryzanowski and Roberts agree that this is a standard general definition of risk. On pages 36-37 of their pre-filed evidence, they quote from a leading finance textbook that applies this general definition to the risk of financial distress associated with excessive leverage. In that context, uncertainty of operating income is associated with an increased probability of financial distress while the types of assets is related to the cost of that distress.

(f) Not applicable as Drs. Kryzanowski and Roberts do not disagree with the definition.

(g) & (h) Drs. Kryzanowski and Roberts agree that the assessment of relative risk should arise from an examination of the main risk drivers. However, it does not follow that factors that are not associated with substantial risk or are common to different entities being compared should be eliminated from the comparison. For this reason, Drs. Kryzanowski and Roberts believe that an abbreviated table as requested would serve little useful purpose.

The report by Mr. Goulding mentioned above is consistent with the position of Drs. Kryzanowski and Roberts. On page 48, that report states that:

> 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.

Witness Panel Responsible: Dr. Lawrence Kryzanowski and Dr. Gordon Roberts

TAB 7

Before the Alberta Utilities Commission (AUC)

In the matter of:

AUC-1578571/ 2009 Generic Cost of Capital Proceeding No. 85

Evidence on Behalf of
Office of the Utilities Consumer Advocate (UCA)

On Cost of Equity and Capital Structures for Applicant Utilities

Text, Appendices and Schedules

Prepared Testimony of

Dr. Lawrence Kryzanowski and Dr. Gordon S. Roberts

Concordia University Research Chair in Finance, John Molson School of Business, Concordia University, Montreal; and CIBC Professor of Financial Services, Schulich School of Business, York University, Toronto.

March 2, 2009

A. We validate this conclusion by comparing our results against those obtained by Ms. McShane in 2007 using a broader sample of 22 Canadian utilities.[166] Her sample includes 11 of our 13 companies (excluding ATCO Pipelines and TransAlta) and adds 11 further companies. We calculate the average allowed, "overly conservative" equity ratio for her sample as 37.28% slightly below our 39%.

Q. Why do call the average allowed ratio "overly conservative"?

A. We call this average equity ratio "overly conservative" because it represents the result of a regulatory process in which decisions by regulatory bodies take as input the views of opposing parties each representing its own interest. We already showed how the regulatory process may be regarded as overly conservative as it almost always results in the regulated companies earning an ROE in excess of the allowed return. Focusing the discussion of conservativism on the common equity ratio leads to a similar conclusion. Regulated utilities have little incentive to optimize the use of debt in their capital structures. Having a capital structure with insufficient debt increases the weighted cost of capital because equity is the most expensive form of financing. In the case of regulated utilities, this "extra" cost associated with insufficient debt may be recovered through the process of regulation. If the company can persuade its regulator to approve this unwarranted extra equity, there is no cost to the company from a higher cost of capital. If this occurs, then the regulated company has unused debt capacity which can be a benefit to the parent holding company. The assets of the regulated utility can then serve as collateral to increase the borrowing power of the unregulated part of the holding company adding value for the shareholders. If this occurs, the shareholders gain unfairly at the expense of the customers of the regulated utility who have to pay higher rates to "compensate" the regulated utility for the cost of carrying unwarranted extra equity.

Q. What other benchmarks do you have for allowed equity ratios?

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166 Kathleen C. McShane, Opinion on Capital Structure and Fair Return on Equity, Prepared for Ontario Power Generation, November 2007, EB-2007-0905, Exhibit C2, Tab 1, Schedule 1, Schedule 30, page 1.

believe that its 47% allowed equity ratio lies above what is appropriate for any of the companies in this hearing.

2.4.5 Recommended Capital Structures for Electric Utilities

Q. Please explain the organization of this section of your evidence.

A. We begin by recapping our business risk ratings for the electric utilities in this hearing as shown in the first row of Schedule 2.15. Next we review the allowed capital structure for each utility in Decision 2004-052 along with any update by the Board or AUC. The following row displays our recommendation for the utility in 2004. The final row shows our recommendation in the current hearing which we explain on a case by case basis. In the interest of avoiding repetition, we refer to, but do not repeat in detail, key points in our business risk analysis. In addition, we refute certain arguments advanced by individual utilities in support of higher equity ratios not covered in our earlier discussion. We return to other such arguments in Section 5 of this evidence.

Q. Kindly review your recommendations for the allowed capital structure for each of the electric utilities.

A. We treat the utilities in alphabetical order. For those companies with both a transmission facility operator (TFO) and distribution company (DISCO) we cover the lower-risk TFO first.

2.4.5.1 <u>AltaLink</u>

Q. Please provide your recommendation for the allowed equity ratio for AltaLink.

A. Our business risk rating for AltaLink is Low, typical of the transmission sector and unchanged since 2004. In Decision 2004-052, the Board assessed the business risk of

Schedule 2.4

Applicant Gas Utilities Sector Business Risk Rating

Applicant	NGTL	ATCO Pipelines	ATCO Gas	AltaGas
Sector	Transmission	Transmission	Distribution	Distribution
Risk		Status Quo		
Market	**M**	**M-H**	**L-M**	**L-M**
Competition	M-H	H	L-M	L
Credit	L	L	L-M	L-M
Supply	M	M	L	L
Operational	**L-M**	**L-M**	**L-M**	**M-H**
Operating Leverage	L-M	L-M	L-M	M-H
Technology	L	L	L	L
Asset retirement/construction	L-M	L-M	L-M	L-M
Regulatory	**L**	**L**	**L**	**L**
Primary regulation	L	L	L	L
Deferral accounts	L	L	L	L
Environmental/safety	L	L	L	L
Overall	**L-M**	**M**	**L-M**	**M**

Drs. Kryzanowski and Roberts, AUC-1578571/Proceeding No. 85.

TAB 8

Ontario Energy Board

EB-2009-0084

Report of the Board

on the Cost of Capital for Ontario's Regulated Utilities

December 11, 2009

current ROE formula would have served to increase the allowed ROE during the recent credit crisis, which, in the Board's view, would have been directionally correct.[64]

The Board has determined that it is appropriate to use a corporate yield variable that is reflective of the borrowing costs of Canadian utilities, one that is well-understood and is based on an established index from a recognized source. **The Board has accordingly determined that it will use a utility bond spread based on the difference between the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond Index yield and the long Canada bond yield.** This is further described in Appendix B.

The Board agrees with the comment of Ms. McShane that separating the LCBF and the utility bond spread variables, as opposed to using one corporate bond yield variable that would implicitly incorporate the LCBF, provides transparency as it shows "what part is causing the ROE to move in either direction."[65]

The Board also determines that the utility bond spread reflected in the reset and refined formulaic ROE approach will be subject to a 0.50 adjustment factor, consistent with the empirical analyses provided by participants to the consultation.

4.3 Capital structure

The Board's current policy with regard to capital structure for all regulated utilities continues to be appropriate. As noted in the Board's draft guidelines, capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals.[66] The Board's current policy is as follows:

[64] Written Comments of the Electricity Distributors Association. September 8, 2009. Schedule 4.
[65] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. Ms. McShane's presentation, p. 161.
[66] Ontario Energy Board. Ontario Energy Board Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 2

- The Board has determined that a split of 60% debt, 40% equity is appropriate for all electricity distributors. [67] Capital structure was not a primary focus of the consultation and the Board notes that the comments made by participants in the consultation largely supported the continuation of the Board's existing policy.

- For electricity transmitters, generators, and gas utilities, the deemed capital structure is determined on a case-by-case basis. The Board's draft guidelines assume that the base capital structure will remain relatively constant over time and that a full reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk. [68]

4.4 Debt Rates

4.4.1 Long-term debt

The determination of the cost of long-term debt was not a primary focus of the consultation and the Board notes that the comments made by participants in the consultation largely supported the continuation of the Board's existing policies and practices.

While the Board agrees with this approach, it is important to note that the determination of the cost of long-term debt has typically received significant interest in the processes to establish electricity distribution and, to a lesser extent, electricity transmission rates. In contrast to the difficulty establishing the utility cost of equity that arises from a lack of transparency, the issues associated with the determination of a utility's long-term debt cost arise from different factors, including the relatively short period of time since the corporatization of electricity distribution and transmission utilities, the relatively short history of rate regulation by the Board, and the presence of significant amounts of affiliate debt.

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[67] Ontario Energy Board. Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors. December 20, 2006. p. 5
[68] Ontario Energy Board. Compendium to Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March, 1997. p. 30

TAB 9

OPG Interrogatory No. 19 to Pollution Probe

Issue 3.3: Should the same capital structure and cost of capital be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure and/or cost of capital parameters are appropriate for each business?

Reference: Pollution Probe's Evidence (Exhibit M, Tab 10), page 66, footnote 60

Preamble:

Drs. Kryzanowski and Roberts calculate the weights based on MWs as follows: "OPG states its total regulated capacities as 6,606 MW nuclear and 3,302 MW hydroelectric for a total of 9,908 MW... The weights are 66.67% nuclear and 33.33% hydro. "

Question:

(a) Please confirm that the 2011 and 2012 rate bases funded by capital structure (debt and equity) for OPG Hydro are approximately $3,800 million and for OPG Nuclear are approximately $2,600 million, so that, based on rate base funded by capital structure, the weights are approximately 60% hydroelectric and 40% nuclear. If this cannot be confirmed, please explain why not.

(b) Please confirm that the Board approved an overall equity thickness for OPG of 47% in EB-2007-0905. If this cannot be confirmed, please explain why not.

(c) Please confirm that the application of a 40% equity ratio to the actual regulated hydroelectric rate base as forecast by OPG and a 50% equity ratio to the portion of nuclear rate base funded by debt and equity as forecast by OPG will result in an overall equity ratio for OPG's prescribed assets financed by capital structure lower than the 47% approved in EB-2007-0905.

(d) Please provide the revised equity ratios for each of the regulated hydroelectric and nuclear operations that would result in an equity ratio for OPG's total hydroelectric and nuclear rate base financed by capital structure of 47% assuming the rate base amounts for each are as forecast by OPG rather than using Drs. Kryzanowski's and Roberts' allocation of total rate base to nuclear and hydroelectric on the basis of capacity. Please explain the rationale for the revisions.

Response:

(a) Drs. Kryzanowski's and Roberts's calculations result in proportions that are close to 60% at 60.2% (i.e. 3803.40 divided by 6321.40) for 2011 and 58.7% (i.e. 3787.40 divided by 6448.10) in 2012 for Hydro. This continues the downward trend in the rate base weight of Hydro since 2008 as shown in the following table:

Rate Base Item	Actual 2009	Budget 2010	Plan 2011	Plan 2012	
Hydro ($M)	3,834.00	3,815.70	3,803.40	3,787.40	[a]
Nuclear ($M)	2,261.50	2,355.50	2,518.00	2,660.70	[b]
Total ($M)	6,095.50	6,171.20	6,321.40	6,448.10	[c]
Hydro (%)	62.90%	61.83%	60.17%	58.74%	
Nuclear (%)	37.10%	38.17%	39.83%	41.26%	
Total (%)	100.00%	100.00%	100.00%	100.00%	

[a]: Filed: 2010-05-26, EB-2010-0008, Exhibit B1, Tab 1, Schedule 1, Table 1: Prescribed Facility Rate Base – Regulated Hydroelectric ($M).
[b]: Total minus Hydro to back out "Adjustment for Lesser of UNL or ARC".
[c]: Filed: 2010-05-26. EB-2010-0008, Exhibit C1, Tab 1, Schedule 1, Tables 1- 6.

(b) Confirmed.

(c) The implicit weights of the equity ratios for Hydro and Nuclear given our recommendations of 40% and 50% that accommodate a fixed (upwardly conservative or "generous") equity ratio of 47% for OPG as a whole are obtained by solving for the weight of Hydro represented by W in (W * 40%) + [(1-W) * 50%] = 47%. Doing such gives similar weights to the weights we used (i.e. Hydro weight of 33% and a Nuclear weight of 67%).

Simple mathematics tells us that using a different weighting scheme will result in a weighted average that is different from 47%. For example, putting more weight on the 40% and less weight on the 50% will lower the weighted average.

Using the rate-base percentages from (a) instead in the calculation thus results in a weighted average of approximately 44% for 2011 and 2012.

(e) Drs. Kryzanowski and Roberts can use "reverse-engineering" logic to obtain the divisional equity ratios that results in the fixed (i.e. "generous") equity ratio of 47% for

OPG as a whole if the rate-base percentages for OPG's "divisions" are used instead to determine the weighted average of the overall equity ratio.

This is done in two-steps. First, one must find the shortfall from the overall weighted equity ratio when one uses the rate-base weights and Drs. Kryzanowski's and Roberts's recommended equity ratios of 40% and 50% for Hydro and Nuclear. From part (c), this is 3%. This 3% shortfall is then allocated to both Hydro and Nuclear so that their resulting equity ratios are 43% and 53% to arrive at the fixed equity ratio of 47% for both test years.

Using weights of 60% and 40% as asked in this interrogatory, the weighted-average equity ratios for OPG as a whole are now: (43% times 60%) plus (53% times 40%), which equals 47%.

The updated credit metrics (i.e. Schedules 5.8A-OPG-IR19 to 5.8D-OPG-IR19) using the rate-base weights instead are attached to these responses as Attachments 1-4. Drs. Kryzanowski and Roberts qualify their assessment of these updated credit metrics by noting that rating agencies consider other factors in addition to coverage ratios in setting ratings and that bond ratings have shortcomings as a timely measure of risk. Nonetheless, they conclude from their analysis of Interest and FFO coverage and Cash Flow to Debt Ratios that, to the extent that such ratios constitute relevant input into bond ratings, the ratios implied by their recommendations are consistent with a bond rating in the A range.

Witness Panel Responsible: Dr. Lawrence Kryzanowski and Dr. Gordon Roberts

Schedule 5.8A-OPG-IR19 (Note: Additions/changes are underlined)

This schedule uses OPG's projections of EBITDA, Taxes, Capitalization and Costs of Equity and Debt to calculate its Interest Coverage Ratio, its FFO Coverage Ratio and its Cash Flow to Debt Ratio for OPG's Hydro Assets for 2012. 'Interest Coverage Ratio' is calculated by dividing 'Allowed $ return on rate base' or 'EBIT' by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'FFO Coverage Ratio' is 'EBITDA (i.e. Funds From Operations or FFO or EBIT as given by 'Allowed $ return on rate base' plus Depreciation & Amortization) divided by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'FFO-AT Coverage Ratio' is 'EBITDA – Taxes') divided by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'Cash Flow to Debt Ratio' is calculated by dividing 'Earnings After Tax' + 'Depreciation & Amortization' by 'Total Debt', where 'Earnings After Tax' equal EBIT minus Taxes. This table uses Hydro's proportion of the rate-base of 58.74% and Hydro's adjusted equity ratio of 43% that ensures that OPG's overall equity ratio remains at 47%.

Capital Structure	Principal	Component (%)	Cost (%)	Cost of Capital ($)
Total debt (% of total)	2,158.94	57.00%	5.58%	120.47
Common equity (% of total)	1,628.67	43.00%	9.85%	160.42
Adjustment for taxes on equity return[a]				27.40
Rate base financed[b]	3,787.61	100.00%		
Allowed $ return on rate base (EBIT)				308.29
Depreciation & Amortization[c]				63.80
EBITDA				372.09

Interest Coverage Ratio (times)	2.56		
FFO Coverage Ratio (times)	3.09	FFO-AT Coverage Ratio (times)	2.86
Cash Flow to Debt Ratio (%)	10.39		

Notes:

[a] Corporate income tax from EB-2010-0008, Exhibit F4, Tab 2, Schedule 1, Table 1, Filed: 2010-05-26.

[b] Total rate base financed by capital structure of 6448.1 million from EB-2010-0008, Exhibit C1, Tab 1, Schedule 1, Table 1, Filed: 2010-05-26, multiplied by 58.74%.

[c] Depreciation & Amortization of 63.4 million plus 0.4 million from EB-2010-0008, Exhibit B2, Tab 4, Schedule 1, Table 2. Filed: 2010-05-26.

Schedule 5.8B-OPG-IR19 (Note: Additions/changes are underlined)

This schedule uses OPG' s projections of EBITDA, Taxes, Capitalization and Costs of Equity and Debt to calculate its Interest Coverage Ratio, its FFO Coverage Ratio and its Cash Flow to Debt Ratio for OPG's Hydro Assets for 2011. 'Interest Coverage Ratio' is calculated by dividing 'Allowed $ return on rate base' or 'EBIT' by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'FFO Coverage Ratio' is 'EBITDA (i.e. Funds From Operations or FFO or EBIT as given by 'Allowed $ return on rate base' plus Depreciation & Amortization) divided by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'FFO-AT Coverage Ratio' is 'EBITDA – Taxes') divided by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'Cash Flow to Debt Ratio' is calculated by dividing 'Earnings After Tax' + 'Depreciation & Amortization' by 'Total Debt', where 'Earnings After Tax' equal EBIT minus Taxes. This table uses Hydro's proportion of the rate-base of 60.17% and Hydro's adjusted equity ratio of 43% that ensures that OPG's overall equity ratio remains at 47%.

Capital Structure	Principal	Component (%)	Cost (%)	Cost of Capital ($)
Total debt (% of total)	2,168.04	57.00%	5.58%	120.98
Common equity (% of total)	1,635.54	43.00%	9.85%	161.10
Adjustment for taxes on equity return[a]				30.6
Rate base financed[b]	3,803.59	100.00%		
Allowed $ return on rate base (EBIT)				312.68
Depreciation & Amortization[d]				63.20
EBITDA				375.88

Interest Coverage Ratio (times)	2.58		
FFO Coverage Ratio (times)	3.11	FFO-AT Coverage Ratio (times)	2.85
Cash Flow to Debt Ratio (%)	10.35		

Notes:

[a] Corporate income tax from EB-2010-0008, Exhibit F4, Tab 2, Schedule 1, Table 1, Filed: 2010-05-26.
[b] Total rate base financed by capital structure of 6321.4 million from EB-2010-0008, Exhibit C1, Tab 1, Schedule 1, Table 2, Filed: 2010-05-26, multiplied by 60.17%.
[c] Depreciation & Amortization of 62.9 million plus 0.3 million from EB-2010-0008, Exhibit B2, Tab 4, Schedule 1, Table 2. Filed: 2010-05-26.

Schedule 5.8C-OPG-IR19 (Note: Additions/changes are underlined)

This schedule uses OPG' s projections of EBITDA, Taxes, Capitalization and Costs of Equity and Debt to calculate its Interest Coverage Ratio, its FFO Coverage Ratio and its Cash Flow to Debt Ratio for OPG's Nuclear Assets for 2012. 'Interest Coverage Ratio' is calculated by dividing 'Allowed $ return on rate base' or 'EBIT' by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'FFO Coverage Ratio' is 'EBITDA (i.e. Funds From Operations or FFO or EBIT as given by 'Allowed $ return on rate base' plus Depreciation & Amortization) divided by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'FFO-AT Coverage Ratio' is 'EBITDA – Taxes') divided by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'Cash Flow to Debt Ratio' is calculated by dividing 'Earnings After Tax' + 'Depreciation & Amortization' by 'Total Debt', where 'Earnings After Tax' equal EBIT minus Taxes. This table uses Nuclear's proportion of the rate-base of 41.26% and Nuclear's adjusted equity ratio of 53% that ensures that OPG's overall equity ratio remains at 47%.

Capital Structure	Principal	Component (%)	Cost (%)	Cost of Capital ($)
Total debt (% of total)	1,250.43	47.00%	5.58%	69.77
Common equity (% of total)	1,410.06	53.00%	9.85%	138.89
Adjustment for taxes on equity return[a]				75.90
Rate Base financed[b]	2,660.49	100.00%		
Allowed $ return on rate base (EBIT)				284.56
Depreciation & Amortization[d]				255.60
EBITDA				540.16

Interest Coverage Ratio (times)	4.08		
FFO Coverage Ratio (times)	7.74	FFO-AT Coverage Ratio (times)	6.65
Cash Flow to Debt Ratio (%)	31.55		

Notes:

[a] Corporate income tax from EB-2010-0008, Exhibit F4, Tab 2, Schedule 1, Table 3, Filed: 2010-05-26.
[b] Total rate base financed by capital structure of 6448.1 million from EB-2010-0008, Exhibit C1, Tab 1, Schedule 1, Table 1, Filed: 2010-05-26, multiplied by 41.26%.
[c] Depreciation & Amortization of 239.5 million plus 16.1 million from EB-2010-0008, Exhibit B3, Tab 4, Schedule 1, Table 1. Filed: 2010-05-26.

Schedule 5.8D-OPG-IR19 (Note: Additions/changes are underlined)

This schedule uses OPG' s projections of EBITDA, Taxes, Capitalization and Costs of Equity and Debt to calculate its Interest Coverage Ratio, its FFO Coverage Ratio and its Cash Flow to Debt Ratio for OPG's Nuclear Assets for 2011. 'Interest Coverage Ratio' is calculated by dividing 'Allowed $ return on rate base' or 'EBIT' by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'FFO Coverage Ratio' is 'EBITDA (i.e. Funds From Operations or FFO or EBIT as given by 'Allowed $ return on rate base' plus Depreciation & Amortization) divided by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'FFO-AT Coverage Ratio' is 'EBITDA – Taxes') divided by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'Cash Flow to Debt Ratio' is calculated by dividing 'Earnings After Tax' + 'Depreciation & Amortization' by 'Total Debt', where 'Earnings After Tax' equal EBIT minus Taxes. This table uses Nuclear's proportion of the rate-base of 39.83% and Nuclear's adjusted equity ratio of 53% that ensures that OPG's overall equity ratio remains at 47%.

Capital Structure	Principal	Component (%)	Cost (%)	Cost of Capital ($)
Total debt	1,183.37	47.00%	5.58%	66.03
Common equity	1,334.44	53.00%	9.85%	131.44
Adjustment for taxes on equity return[a]				53.9
Rate base financed[b]	2,517.81	100.00%		
Allowed $ return on rate base (EBIT)				251.37
Depreciation & Amortization[d]				234.50
EBITDA				485.87

Interest Coverage Ratio (times)	3.81		
FFO Coverage Ratio (times)	7.36	FFO-AT Coverage Ratio (times)	6.54
Cash Flow to Debt Ratio (%)	30.92%		

Notes:

[a] Corporate income tax from EB-2010-0008, Exhibit F4, Tab 2, Schedule 1, Table 3, Filed: 2010-05-26.
[b] Total rate base financed by capital structure of 6321.4 million from EB-2010-0008, Exhibit C1, Tab 1, Schedule 1, Table 2, Filed: 2010-05-26, multiplied by 39.83%.
[c] Depreciation & Amortization of 218.9 million plus 15.6 million from EB-2010-0008, Exhibit B3, Tab 4, Schedule 1, Table 1. Filed: 2010-05-26.

OPG Interrogatory No. 20 to Pollution Probe

Issue 3.3: Should the same capital structure and cost of capital be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure and/or cost of capital parameters are appropriate for each business?

Reference: Pollution Probe's Evidence (Exhibit M, Tab 10), Schedule 5.7

Preamble:

Drs. K[ryzanowski] and R[oberts] categorize different utilities along with their regulated equity ratios by type, transmission, distribution and integrated. OPG would like to better understand what factors determine whether a utility is categorized as distribution or integrated.

Question:

(a) Drs. K[ryzanowski] and R[oberts] categorize Newfoundland Power and Maritime Electric as integrated utilities. What are the criteria for categorizing utilities as integrated rather than distribution electricity utilities?

Response:

(a) Drs. Kryzanowski and Roberts categorize a company as an integrated utility when it includes significant elements of generation, transmission and distribution. For example, Maritime Electric states on its website that it "owns and operates a fully integrated system providing for the generation, transmission and distribution of electricity to customers throughout Prince Edward Island".[1] Further, Newfoundland Power's website states that the company "operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador".[2]

Witness Panel Responsible: Dr. Lawrence Kryzanowski and Dr. Gordon Roberts

[1] Available online at http://www.maritimeelectric.com/about_us/ab_corporate_profile.asp.
[2] Available online at http://www.newfoundlandpower.com/AboutUs/Profile.aspx.