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").

POLLUTION PROBE

CROSS-EXAMINATION REFERENCE BOOK FOR OPG PANEL 8

October 26, 2010

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Ontario

ONTARIO ENERGY BOARD

FILE NO.:	EB-2010-0008	
VOLUME:	6	
DATE:	October 18, 2010	
BEFORE:	Cynthia Chaplin	Presiding Member and Vice-Chair
	Cathy Spoel	Member
	Marika Hare	Member

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"Therefore the average annual capacity utilization rate of the Pickering A units 1 and 4 nuclear reactors during the past four years was only 64 percent."

Do you see that?

MR. REINER: Yes, I do.

MR. ALEXANDER: Would you agree with that?

MR. REINER: Again, subject to validating the data behind this, I am assuming it is correct.

MR. ALEXANDER: And you have no reason to dispute it?

MR. REINER: I have no reason to dispute it.

MR. ALEXANDER: And then the next paragraph underneath that, the next underlined paragraph is:

"To date, Bruce Power has rebuilt two of its nuclear reactors, namely Bruce A units 3 and 4. Their average annual capacity utilization rate during the last four years was 75 percent."

Do you see that?

MR. REINER: I see that.

MR. ALEXANDER: Do you agree with that?

MR. REINER: I can't comment. Those are Bruce Power's units, and again, subject to having the data, but --

MR. ALEXANDER: But you have no reason --

MR. REINER: -- once again, I don't have a reason to dispute the numbers, no.

MR. ALEXANDER: Now, if I could change topics and move on to a different one, if I could get you to move to page 2 of the report, the next page, which is page 3 of the

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document book marked as Exhibit K6.3; do you have that?

MR. REINER: Page 3? Yes.

MR. ALEXANDER: And then you've got a number 3 in the left column, and an underlined portion in that paragraph.

Do you see that?

MR. REINER: Yes.

MR. ALEXANDER: And that unlined portion states:

"According to CIBC World Markets, only 20 to 40 percent of Bruce Power's Bruce A units 1 and 2 restart project could be debt-financed, and its required return on equity could be up to 18 percent."

Do you see that?

MR. REINER: I see that, yes.

MR. ALEXANDER: Do you agree with that statement?

MR. REINER: I can't comment.

MR. ALEXANDER: Do you have any reason to dispute it?

MR. REINER: I don't have a reason to dispute it, no.

MR. ALEXANDER: Does OPG believe that the Darlington rebuild project has a lower risk than the Bruce A units 1 and 2 restart project?

MR. REINER: No. I can't comment on detail on the Bruce A units 1 and 2 restart project. Those are not OPG's projects.

But what I can say is that there are a number of measures that we are taking to mitigate the risk, and many of those measures are based on the operating experiences that we are seeing that others have encountered.

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So, for example, the kinds of things that we are incorporating into the Darlington refurbishment project is we are allowing for sufficient time, in advance of executing the work, to plan the work, and that would be -- I would characterize that as having been a weakness in the Bruce project.

We are also looking at specific contracting strategies that ensure that we have got all of the vendors appropriately aligned on a common set of objectives that align with our objective for the refurbishment, which would be to execute the project on schedule and on budget.

And I also know, from operating experience on Bruce, that the project management was subcontracted initially, and then was taken back by Bruce Power. So there are experiences that Bruce has encountered that we are building into the learnings in preparing for the Darlington refurbishment. And so based on that, I would draw the conclusion that we will be in a better position to mitigate some of those risks just having seen that kind of experience.

MR. ALEXANDER: The focus of my question is on the financing perspective. So what I am trying to understand is whether or not you consider Darlington to be of a lower risk than the Bruce nuclear situation, given the -- given what is here?

MR. REINER: Are you referring back to number 3 here on this 40 percent of Bruce Power units 1 and 2 restart project could be debt -- back to that statement?

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MR. ALEXANDER: Well, the statement itself isn't important, but what I am trying to understand is the relative risk, from a financial point of view, for financial purposes; right?

MR. REINER: Yes.

MR. ALEXANDER: So do you see the Darlington rebuild as having a lower risk than the Bruce restart for financial purposes?

MR. REINER: In terms of our ability to finance the project, is that what you are asking, or are you asking in terms of what our assumptions are on cost to execute the project? I am not sure what you are after.

MR. ALEXANDER: Would the market perceive your project, the Darlington project, as lower risk or higher risk relative to the Bruce A restart?

MR. REINER: Now, that question may be one of the things -- I should say it may be -- there may be a future panel, corporate finance panel, that could probably address that. But the assumptions that we are making around accessing the market to finance Bruce -- or to finance Darlington refurbishment are based on assumptions related to what our cost and our ability to raise the capital actually is, and that's been factored into our analysis.

Now, that does differ from this statement, so to that extent they are not the same.

Now, how that translates to risk, we don't believe we have a significant amount of risk in acquiring the financing that is needed to execute the project. So I

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would say, from that perspective, it is probably a lower risk than Bruce A.

MR. ALEXANDER: For my reference, is OPG seeking or planning to seek financing from the Ontario Electricity Financial Corporation for the Darlington rebuild project?

MR. REINER: Sorry, could you --

MR. ALEXANDER: Is OPG seeking or planning to seek financing from the Ontario Electricity Financial Corporation for the Darlington rebuild project?

MR. REINER: One of our deliverables in the planning phase that we are now in is to confirm the financing for the project, and, to the extent that that is an option, we will evaluate it.

But that is something that we will be assessing in the planning phase of the project.

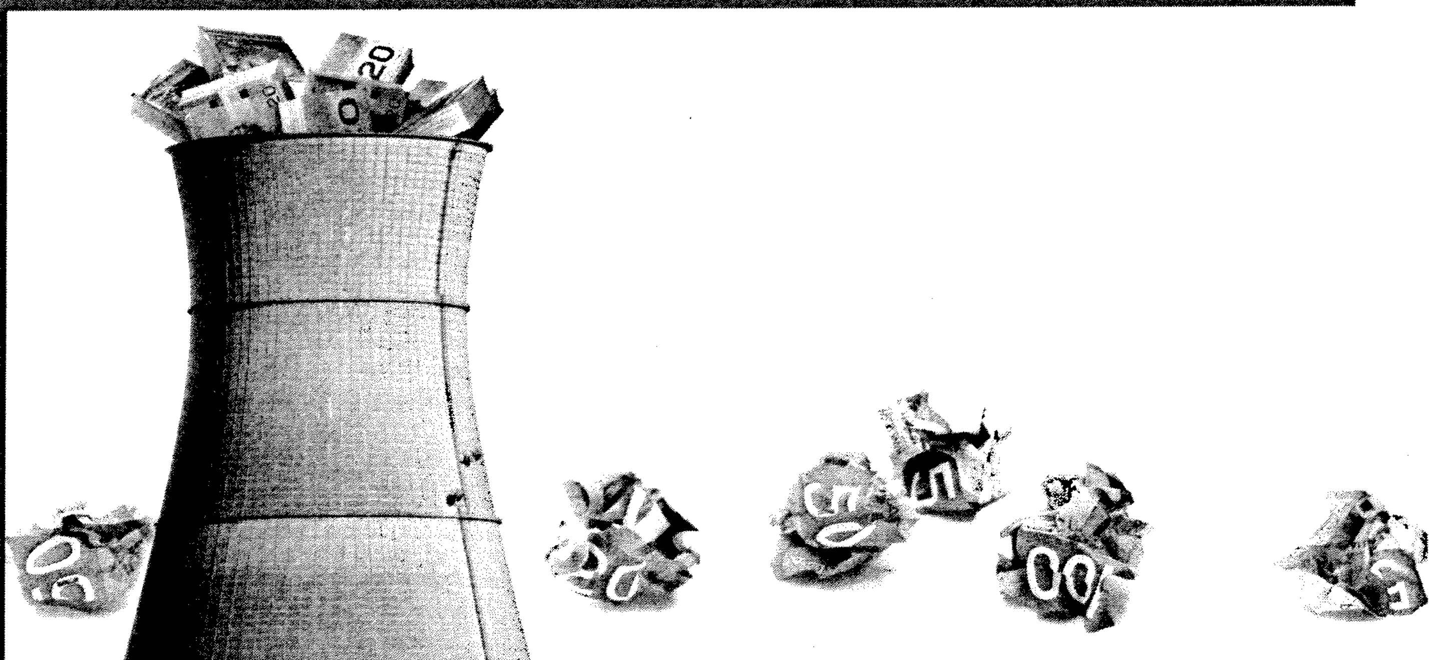
MR. ALEXANDER: So you don't know yet, or you are going to, or you are planning to or you are not going to do it?

MR. REINER: We don't know yet, and we are -- we are planning to do the work needed to ensure that the financing is available. The exact vehicles and sources of that financing, I can't yet comment, since that work hasn't been done.

MR. ALEXANDER: I will move on to another topic. And if I could get you to turn to tab 5 of the cross-examination reference book, Exhibit K6.3, page 16, do you have that?

MR. REINER: Yes.

The Darlington Re-Build Consumer Protection Plan



AN OCAA RESEARCH ENERGY REPORT | www.cleanairalliance.org

Ontario Clean Air Alliance Research Inc.

SEPTEMBER 23, 2010

3. OPG has underestimated the required commercial risk-adjusted rate of return on capital for this high-risk project. Specifically, OPG assumes the project can be 53% debt financed and its required rate of return on equity would be only 9.85%.[15] On the other hand, according to CIBC World Markets, only 20 to 40% of Bruce Power's Bruce A Units 1 and 2 Re-Start project could be debt financed and its required return on equity could be up to 18%.[16] According to OPG, assuming 30% debt financing and a 18% return on equity, the cost of the Darlington Re-Build rises to 10 to 14 cents per kWh (assuming an 82% average annual capacity utilization rate) or 12 to 18 cents per kWh (assuming a 64% average annual capacity utilization rate).[17]

4. OPG's analysis assumes that the Darlington Re-Build project will be completed on budget despite the fact that every nuclear project in Ontario's history has experienced huge capital cost overruns (see Appendix A). Similarly, the retrofit of the Point Lepreau reactors in New Brunswick is reported to be massively over budget despite assurances at the outset of the project that the pattern of massive cost overruns would not be repeated. [66]

   On average, the actual costs of Ontario's nuclear projects have been 2.5 times greater than their original cost estimates. If the Darlington Re-Build's actual cost exceeds OPG's original cost estimate range by 2.5 times then its final cost will be $21.25 to $35 billion. As a consequence, it will produce electricity at a cost of 19 to 27 cents per kWh (assuming an 82% average annual capacity utilization rate) or 24 to 37 cents per kWh (assuming a 64% average annual capacity utilization rate).[18]

Lower Cost and Lower Risk Options

Fortunately Ontario has numerous lower cost and lower risk options to meet its electricity needs. Specifically, improving energy efficiency; reducing wasteful natural gas usage; and water power imports from Quebec.

Energy Efficiency

Energy efficiency is the lowest cost option to meet our electricity needs. However, as the following facts reveal the Ontario Power Authority (OPA) is not aggressively pursuing the province's low cost energy efficiency investment opportunities.

1. As of December 31, 2009, the OPA's total spending on energy conservation and demand management was $541.6 million; whereas it has contracted for electricity supply projects with a total capital cost of $23.622 billion.[19] That is, for every dollar that it has spent on energy conservation and demand management, it has contracted for $44 of new supply.

2. The OPA's *Industrial Accelerator Program* pays large industrial customers up to 23 cents for each kWh that their energy efficiency investments save *during the first year* of their operation. [20] Assuming these investments actually deliver savings for at least 5 to 10 years, a payment of 23 cents per kWh saved *during the first year* is equivalent to an average annual payment of only 2.3 to 4.6 cents per kWh. That is, OPA's payments for saving a kWh are therefore 76 to 94% less than the cost of producing a kWh by re-building Darlington.

Ending Wasteful Natural Gas Use

Most buildings and factories in Ontario use natural gas to produce just one service, namely heat. It is much more efficient to use these same molecules of natural gas to simultaneously produce heat and electricity. This is what combined heat and power (CHP) plants do. They can have energy efficiencies of 80 to 90% compared to the 33% energy efficiency of a nuclear reactor.[21]

CHP plants can be installed in apartment buildings, condominiums, shopping centres, hospitals, schools, airports and factories.

According to the OPA, CHP plants can supply electricity at a total cost of 5.7 to 6.0 cents per kWh assuming a natural gas cost of $8 per

Endnotes

1 Ontario Energy Board Docket No. EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Page 6.

2 Ontario Energy Board Docket No. EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Page 11.

3 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 10, Schedule 014.

4 Ontario Energy Board Docket No. EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Page 10.

5 Ontario Energy Board Docket No. EB-2010-0008, Exhibit JT1.2.

6 Ontario Energy Board Docket No. EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Pages 4 & 5.

7 Ontario Energy Board Docket No. EB-2010-0008, Undertaking JT1.3.

8 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 10, Schedule 002.

9 Ontario Ministry of Energy, Science and Technology, *Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario*, (November 1997), page 7. The Ontario nuclear industry often claims higher average capacity utilization rates by ignoring the performance of reactors that are temporarily or permanently and pre-maturely shutdown.

10 Email from Carrie Reid, Customer Relations, Independent Electricity System Operator to Jack Gibbons, Ontario Clean Air Alliance, June 24, 2010.

11 OPG Review Committee, *Transforming Ontario's Power Generation Company*, (March 15, 2004), Page 50.

12 Email from Carrie Reid, Customer Relations, Independent Electricity System Operator to Jack Gibbons, Ontario Clean Air Alliance, June 24, 2010.

13 Emails from Carrie Reid and Rebecca Short, Customer Relations, Independent Electricity System Operator to Jack Gibbons, Ontario Clean Air Alliance, July 21, 2010 and September 14, 2010.

14 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 10, Schedule 004.

15 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 6, Schedule 002 and Tab 10, Schedule 002.

16 Letter from CIBC World Markets Inc. to James Gillis, Ontario Deputy Minister of Energy, October 17, 2005.

17 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 10, Schedule 006.

18 According to OPG, assuming 70% equity financing and a required equity rate of return of 18%, the Darlington Re-Build will produce electricity at a total cost of 10 to 14 cents per kWh (assuming an 82% capacity utilization rate) or 12 to 18 cents per kWh (assuming a 64% capacity utilization rate). Furthermore, according to OPG, the Darlington Re-Build's non-capital costs (i.e., operating, maintenance, administration and fuel costs) are 3.9 to 5.2 cents per kWh. All costs are in 2009$. We have increased OPG's estimated capital costs per kWh by a factor of 2.5 to calculate the impact of a 150% capital cost overrun on the Darlington Re-Build's total cost of power. Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 10, Schedules 003 and 006.

19 Ontario Clean Air Alliance, *Conservation vs. Electricity Supply: A summary of the Ontario Power Authority's procurement efforts*, (July 19, 2010).

20 Ontario Power Authority, *Industrial Accelerator Program: Program Rules Version 2.0*, (June 24, 2010), pages 13, 14 & 15.

21 Ontario Power Authority, *Supply Mix Analysis Report*, Volume 2, (December 2005), page 210; and *Integrated Power System Plan*, Exhibit G, Tab2, Schedule 1, page 7.

22 Assuming energy efficiencies of 80 to 90% and an average annual capacity utilization rate of 90%. Ontario Power Authority, *Integrated Power System Plan*, Exhibit I, Tab 31, Schedule 90.

23 Ontario Power Authority, *Integrated Power System Plan*, Exhibit I, Tab 31, Schedule 21, page 1.

24 *Integrated Power System Plan*, Exhibit L, Tab 8, Schedule 7: Thomas R. Casten, Recycled Energy Development LLC, *The Role of Recycled Energy and Combined Heat and Power (CHP) in Ontario's Electricity Future*, page 3.

25 Catherine Strickland & John Nyboer, MK Jaccard and Associates, *Cogeneration Potential in Canada: Phase 2*, (April 2002), page 30.

26 Hagler Bailly Canada, *Potential for Cogeneration in Ontario: Final Report*, (August 2000), page 25.

27 Ontario Power Generation, *Sustainable Development Report 2009*, page 46.

28 Ontario Energy Board Docket No. EB-2008-0272, Exhibit I, Tab 5, Schedule 6.

29 Hydro Quebec, *Annual Report 2009: Shaping The Future*, page 53.

30 Ontario Power Authority, *A Progress Report On Electricity Supply: First Quarter 2010*, pages 6, 24 & 25.

31 Steve Erwin, "Bruce nuclear cost overruns will fall in taxpayers' laps: critics", *Brockville Recorder and Times*, October 18, 2005.

32 Tyler Hamilton, "Reactor repairs confirmed over budget", *Toronto Star*, April 18, 2008.

33 *Second Amending Agreement to the Bruce Power Refurbishment Implementation Agreement Between Bruce Power L.P. and Bruce Power A L.P. and Ontario Power Authority*, July 6, 2009. Available online at: www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=891.

34 Ontario Ministry of Energy, *News Release*, "Ontario Takes Next Step To Ensure Clean, Affordable And Reliable Energy Supply For Generations To Come", (March 7, 2008).

35 According to the Government's news release, "The competitive process will help to ensure the greatest amount of cost certainty, lowest possible price and a fair approach to risk sharing." See Infrastructure Ontario, *Backgrounder*, "Nuclear Procurement Project Phase 2", (June 16, 2008).

VT INCEPIT FIDELIS SIC PERMANET

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2007-0905**

VOLUME:	**15**	
DATE:	**June 20, 2008**	
BEFORE:	**Gordon Kaiser**	**Presiding Member and Vice Chair**
	Bill Rupert	**Member**
	Cynthia Chaplin	**Member**

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capital structure and ROE for our regulated assets or our regco was that Ms. McShane's analysis was that she couldn't land on a robust methodology for determining those separate capital structures and ROEs.

MR. ALEXANDER: Does OPG have any philosophical or pragmatic objections to calculating its charges for its nuclear and hydroelectric supplies using different OEB-approved cost of capital?

MR. BARRETT: I don't think we have any principled objection. I think there is a pragmatic issue there, in terms of being able to do it, to calculate the right numbers in a robust fashion. I guess at the end of the day, if we were able to recover the same amount of money to cover the pool of business and financial risks that we have in the regco business, then I don't see us having a principled objection.

MR. ALEXANDER: And that pragmatic concern, is that your only pragmatic concern?

MR. HALPERIN: I think so, at this point.

MR. BARRETT: That's all that we have, yes.

MR. ALEXANDER: Thank you, panel. I have no further questions, and I would ask to be excused.

MR. KAISER: Thank you. Mr. Thompson.

MR. THOMPSON: Mr. Rubin is anxious to precede me.

MR. KAISER: All right. Mr. Rubin.

CROSS-EXAMINATION BY MR. RUBIN:

MR. RUBIN: Thank you, Mr. Chair. Hello, panel.

Ontario Energy Board
Commission de l'énergie de l'Ontario

Ontario

EB-2007-0905

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES

DECISION WITH REASONS

November 3, 2008

through applications, deferral accounts, and motions to review. These are standard and well established regulatory tools; cost of service is a long established regulatory framework; even incentive regulation is well established.

The Board does accept that there could be some risk associated with the uncertainty of applying cost of service regulation, which is typically applied to natural monopolies, to generation assets in Ontario's hybrid market. However, the Board notes that throughout North America there continues to be rate regulation of generation facilities, and that the traditional models of cost of service or incentive regulation are applied in these circumstances. The Board concludes that the risk is therefore minimal.

The risk with respect to the CNSC is whether OPG would be able to recover the costs arising from CNSC action. The Board does agree that it is a category of costs not faced by other regulated Ontario utilities. However, the Board expects that were such costs to arise, OPG would apply for recovery through an application, as would any other regulated entity faced with a significant cost which it claimed was beyond its control and imposed by a body with the authority to do so. The Board would consider the application in the normal way, including a test of prudence.

The Board concludes that regulatory risk is not a significant factor for OPG and is not materially higher for it than for the other utilities the Board regulates.

8.3.4 Operating Risk

For OPG, operating risk entails outage risk, dispatch risk, non-payment risk and the risk associated with environmental obligations. There was general agreement that electricity generators have greater operational risks than non-generation entities regulated by the Board. It was also generally agreed that OPG's risks were lower than those of merchant generators. Given the proposed continuation of the deferral account covering fluctuations in water availability during the test period for the hydroelectric operations, the focus was largely on OPG's nuclear operations and primarily on the risk related to forced outages and dispatch.

OPG took the position that although much has been made of deferral and variance account protection in this case, most of the accounts are simply reflections of the prohibition against retroactive rate making; i.e., they are designed to ensure the recovery of costs associated with initiatives that were directed, authorized or approved changes/assessments) were not implemented, the increased risk would warrant an upward adjustment to either the equity ratio or the ROE.

OPG argued that the evidence is clear that Ms. McShane's recommendations are premised on the approval of the proposed deferral and variance accounts, and that if they are not approved, the equity ratio and/or ROE would need to be adjusted accordingly. OPG submitted that if the scope of the accounts, including, for example, the Nuclear Liabilities Deferral Account, is reduced, then OPG's risk will increase which would need to be reflected in the cost of capital.

Mr. Goulding testified that the fixed payment component would reduce OPG's business risk and pointed out that this payment structure would not be available to merchant generators nor to the generators under contract with the OPA. Ms. McShane estimated that without the fixed payment component, the ROE would need to increase by about half the increase in the variability, approximately 25 basis points, or the equity component should be increased to 60%.

Board Findings

The Board finds that while the dispatch risk for the regulated facilities is low, the operational and productions risks, particularly for the nuclear assets, are significant. Some of these risks are mitigated by the existing and ongoing deferral and variance accounts, but the accounts do not cover all of the risk, particularly not the risk of forced outages and the corresponding impact on costs and production. The accounts fall into four categories: those not related to the prescribed assets; one which provides for recovery of costs which pre-date the Board's regulation of OPG; those that have been specifically approved by the Board in this decision and are typical of utility variance and deferral accounts; and those which provide extended protection against forecast variance. We will review each in turn.

Some of the accounts and cost recovery protection mechanisms contained in O. Reg. 53/05 do not relate to the prescribed assets. The Board is required to ensure that OPG recovers the costs associated with Bruce and the costs associated with new nuclear build. Although these represent significant shifts of costs and risks to customers, they are not related to the regulation of the prescribed facilities. The Board finds that although these requirements may lower OPG's risk as a corporation, they have no impact on the risks of the prescribed facilities.

One of the accounts relates to circumstances and decisions taken before the period in which the Board has regulatory authority. The PARTS account is related to non-capital expenditures related to Pickering A which pre-date the period of the Board's regulatory authority. No new amounts will be added to this account; it is being maintained as the amounts are recovered over the next four years. The Board concludes that this account has no significant impact on OPG's risk in the test period, as the expenditures pre-date the Board's regulatory authority.

Some of the approved accounts going forward are related to protection against forecast error, namely tax changes, nuclear fuel cost, water conditions and ancillary services. The Board concludes that while these accounts each reduce risk, they are not dissimilar to the accounts of other regulated utilities. The electric LDCs have accounts related to tax changes; the ancillary services account ensures customers receive the full benefit of these revenues; and the nuclear fuel and water accounts, while providing protection against inputs over which OPG has little control, are not large relative to the size of OPG's revenue requirement.

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. This protects OPG against a significant risk. The refurbishment account provides protection against forecast variance in non-capital costs; this could be significant given the high levels of project OM&A. While the account also provides protection related to capital costs, these costs will not be included in rate base until the assets are in-service in any event and therefore the account does not provide significant additional risk protection. The requirement for a prudence review continues to provide a measure of protection to customers and ensures that OPG retains some risk.

The Board notes that future accounts may be established which further reduce risk; however, that factor is not determinative of the Board's assessment of the current level of risk. The proposed payment structure would also mitigate some of the risk, but as set out in Chapter 9, the Board has determined that it is not appropriate to include a fixed component in the payment structure.

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). The Board also concludes that it is not appropriate for the shareholder to be compensated for all of the operational risks associated with the regulated nuclear facilities. Under cost of service regulation OPG has the opportunity to forecast production and operating costs and to seek recovery of the associated revenue requirement. The Board concludes that it would not be appropriate for shareholders to be fully compensated for the risk that those forecasts are incorrect given that management controls the development of the forecasts and has some considerable control over the achievement of those forecasts.

8.3.5 Capital Structure Conclusion

CCC concluded that OPG was no riskier than any other utility and that Dr. Booth's recommended equity ratio of 40% was appropriate. Similarly, AMPCO took the position that OPG and Ms. McShane have exaggerated the risks facing OPG and concluded that the equity ratio should remain unchanged. SEC submitted that the equity component should be 47%, representing 40% for hydroelectric and 50% for nuclear. OPG replied that those who have recommended lower equity ratios than Ms. McShane have underestimated OPG's business risk.

Board Findings

Union Gas Limited and Enbridge Gas Distribution Inc. both have equity ratios of 36%, and the risk differential between Union and Enbridge is reflected in Union's ROE which is 15 basis points higher. The electric LDCs and Hydro One have equity ratios of 40%, and Great Lakes (transmission) has an equity ratio of 45%. The Board has concluded that OPG is of higher risk than electricity LDCs, gas utilities and electricity transmission utilities and of lower risk than merchant generation. And while the deferral and variance accounts mitigate some aspects of OPG's risk, they do not protect against outage risk.

The Board finds that the proposed equity ratio of 57.5% is excessive. The incremental level of risk does not warrant the additional 12.5% equity over that of the next highest regulated utility. It is also well in excess of the equity levels of merchant generators, who have higher risk than OPG, as pointed out by Mr. Goulding. 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

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.

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Opinion

on

Capital Structure and Fair Return on Equity

Prepared for

ONTARIO POWER GENERATION

Prepared by

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.

November 2007

account in future, there is no guarantee that OPG will be allowed to recover 100% of the incurred costs.

B.4.c. Regulatory Risks

Chapter IV.B.2.c. discusses the regulatory environment as it impacts the composite regulated operations of OPG, including the nuclear operations. The key elements of the regulatory framework as they relate specifically to nuclear operations are discussed below.

Regulation 53/05 established several deferral and variance accounts for the nuclear operations. These included deferral and variance accounts for:

(1) non-capital costs associated with the return to service of Pickering A nuclear generating station units (PARTS Deferral Account);
(2) costs incurred prior to the Board's first rate order to refurbish, increase or add generation capacity or to develop new nuclear capacity (Increased Capacity/Output and Refurbishment Deferral Account);
(3) transmission outages and restrictions; and
(4) ONFA related costs (Nuclear Liabilities Deferral Account); and
(5) unforeseen changes in nuclear technology or regulatory requirements.

OPG is proposing to recover amounts accumulated in the PARTS deferral account over a period of 15 years; the only additional costs that will be added to this account are carrying costs. The costs accumulated in the Increased Capacity/Output and Refurbishment Deferral and the Nuclear Liabilites Deferral Accounts as of December 31, 2007 are forecast to be recovered in regulated payments by the end of 2010. As indicated above, OPG is proposing to eliminate the variance accounts for transmission outages and restrictions, Acts of God and unforeseen changes in nuclear technology or regulatory requirements (with the proviso that OPG may apply for accounts in the future should the related costs result in a material financial impact).

OPG faces significant capital expenditures for refurbishment of existing or to build new regulated nuclear facilities.[83] The undertaking of the refurbishment of existing nuclear unit or construction of a new nuclear plant would raise the risks to which the utility is exposed. With respect to new nuclear plant construction, S&P is of the view that, despite the recent excellent performance of nuclear plants, historic risks will persist throughout a new plant's life cycle. These risks include cost growth, design and scope changes, permitting delays, public opposition, regulatory changes, latent technical defects, and uncertain decommissioning costs. All else being equal, S&P has concluded, an electric utility with nuclear exposure has weaker credit than one without.[84]

The requirement to refurbish existing nuclear plants, or build new nuclear generation facilities would entail an extended period between development, construction and putting those assets into service. Allowing CWIP in rate base in a period of high capital expenditures related to a fundamentally risky nuclear generation plant would help mitigate the increase in risks. As discussed above, my recommendations are premised on the inclusion in rate base of CWIP related to specific projects where the costs are relatively large and the planning and construction period are extended, including the refurbishment of a nuclear facility or a new build.

B.5. Relative Business Risks of OPG's Regulated Operations

With respect to relative business risk, OPG's regulated operations face significantly higher business risks than the typical Canadian utility and the typical vertically integrated electric utility in Canada or the U.S., for the following reasons:

a. As a generation-only business, OPG's regulated operations have no low risk monopoly "wires" or distribution "pipes" operations. Generation is inherently subject to higher

[83] S&P has indicated that the "sheer amount of capital necessary to bring a new [nuclear] plant on line is daunting." S&P, *U.S. Is Looking at a Paced Reemergence of the Nuclear Power Option*, June 26, 2006.
[84] S&P, *Time for a New Start for U.S. Nuclear Energy?*, June 4, 2003.

market/competitive risks than "wires" or distribution "pipes", for which the probability of duplication of facilities is virtually nil. Generation is also subject to higher operating and production risks than "wires" or "pipes" operations.

b. The existing nuclear plants are subject to significantly higher production/operating risks than other types of generation.

c. While the risk-sharing of used fuel obligations with the government caps OPG's nuclear liability and the Nuclear Liabilites Deferral Account for ONFA costs mitigates the risks related to the nuclear liabilities, the long-run risks remain higher for OPG than for utilities with either no nuclear exposure, exposure tempered by the smaller size of nuclear operations relative to total operations, or where the government assumes the risk for a fee (as is the case in the U.S. for used fuel).

d. Regulatory risks are relatively high; there remains a risk of further political intervention that could alter OPG's ability to recover a reasonable return on (or return of) the invested capital; and

e. Potentially high levels of capital expenditures for refurbishment and new plant construction expose OPG to significant cost recovery risks.

C. IMPORTANCE OF INVESTMENT GRADE DEBT RATINGS

In contrast to unregulated companies, public utilities have obligations that require them to raise capital "on demand". Although OPG's regulated operations are not governed by the traditional obligation to serve, its mandate includes continuous improvement of its nuclear generation fleet, including refurbishment of older units, and expansion, development and improvement of its hydroelectric generating capacity. In August 2007, the Ontario Power Authority (OPA) delivered to the Ontario Ministry of Energy its proposed 20-year plan for the Province's electricity system. The plan outlined by OPA (subject to government approval) has been estimated to cost approximately $60 billion. In response to the OPA's initial recommendations (December 2005's *Supply Mix Advice and Recommendation Report*), OPG was directed by the government to begin an assessment of the refurbishment of existing nuclear units and the construction of new units. The success and cost of implementing the plan will depend in part on the ability of OPG and other generators to raise funds when required and on reasonable terms and conditions. If OPG is to be able to achieve a sustainable financial model as envisioned under the Memorandum of Agreement between OPG and the Province of Ontario, it needs to be able to access funds from the public markets for refurbishment and expansion.

In my opinion, to ensure access to the public markets, the capital structure for OPG's regulated operations should be sufficient to achieve debt ratings on a stand-alone basis in the A category. While debt ratings of BBB- or better are considered investment grade, debt ratings in the A category provide assurance that a utility will be able to access the debt markets as required on reasonable terms and conditions over the full interest rate or business cycle. If OPG is directed to refurbish or build new generating facilities, it will not have the flexibility to defer financing that an unregulated firm has.

Generation assets are long-lived. The life span of a nuclear generation facility is expected to be approximately 40 years; hydroelectric generation facilities can operate for periods in excess of 100 years. With long-lived assets, OPG needs to be able to access the long-term debt markets consistently. Financing long-term assets with short-term debt creates a mismatch between recovery of the investment in regulated payments and the return to investors of the capital committed, and exposes the utility to higher refinancing risk. Debt ratings in the A category will provide better assurance of predictable access to the long-term debt markets on reasonable terms and conditions than would BBB ratings.

Utilities with ratings in the BBB category not only will have to pay more for debt than A rated utilities, but they may have more onerous conditions attached to debt issues. In recent years, the spread between long-term BBB rated utility debt and A rated utility debt in Canada has been as high as 175 basis points.[85] In the U.S. over the past five years, the spread between A and Baa long-term utility bonds has been as high as 85 basis points. Of particular concern would be that a BBB rated utility would, at times, be completely shut out of the long-term (30-year) debt market.[86]

A utility with split ratings (that is, one debt rating agency rates the company's debt in the A category and another debt rating agency rates it in the BBB category) could face a materially higher cost of debt than a utility with both ratings in the A category. Debt investors are likely to take the lowest rating into account when pricing an issue. To illustrate, the credit spreads for new 30-year bond issues for Canadian utilities with split ratings have been approximately 35 basis points higher than for Canadian utilities for which all debt ratings are in the A category. Within the past five years, the spread differentials have been as high as approximately 65 basis points.

The public market for BBB rated debt remains more limited in Canada than in the U.S. Many institutions, who are major purchasers of corporate debt issues, either may not purchase BBB rated debt or have limitations on the proportion of BBB rated debt that they can hold in their portfolio. If an issuer's debt is downgraded further, into a non-investment grade category, the institution may have to dispose of its holdings in those securities. To illustrate, the NEB reported in its August 2005 *Canadian Hydrocarbon Transportation System Report* that Canadian bonds are an important revenue source to pension funds and other institutional investors, and a downgrade could require institutional holders to sell a large percentage of their bonds at discounted prices.[87]

[85] Based on a comparison between the indicated spreads for TransAlta Corporation and Canadian utilities whose debt ratings are all in the A category.
[86] FortisBC, for example, rated at the time Baa3 by Moody's and BBB(high) by DBRS, had a difficult time during late 2004 and early 2005 accessing the 30-year debt market, despite the fact that the debt markets at the time were some of the most robust that had been experienced in Canada for years.
[87] More generally, the pension funds had indicated to the NEB that the basic financial parameters (allowed return on equity and deemed capital structure) in the Board's regulatory scheme should be improved.

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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.

August 2010

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

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[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.

ONTARIO POWER GENERATION

File No: N-REP-00120.3-10000-R000

Project ID - 16-27959

Economic Feasibility Assessment of Darlington Refurbishment

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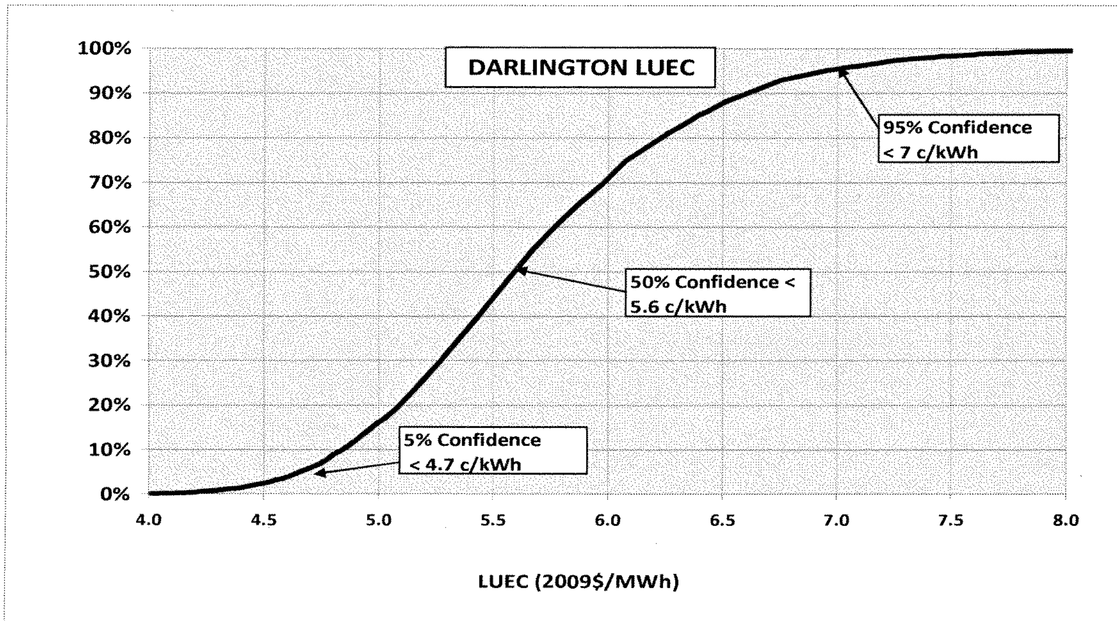
Contents

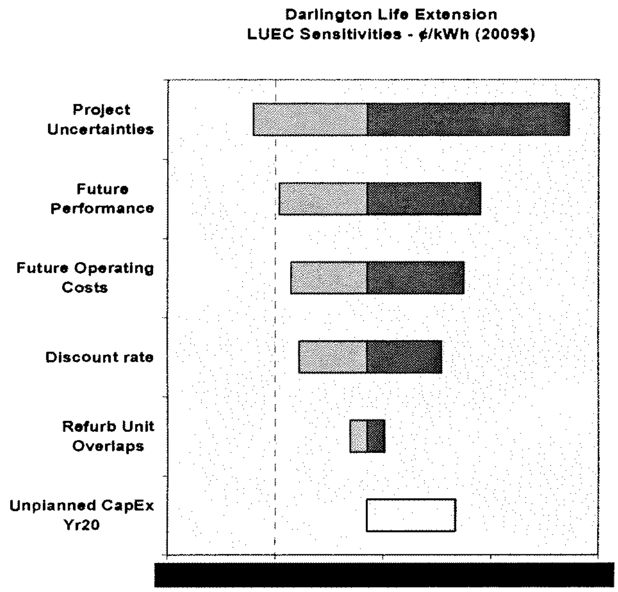
Figure 2: Levelized Unit Energy Cost Confidence Ranges



2.2. Sensitivity of Results to Changes in Input Assumptions

As documented in Section 1, this Updated Economic Assessment includes a large number of assumptions regarding refurbishment costs and durations, going forward operating and sustaining investment costs and operating performance. For each of these factors, ranges were developed and sensitivity analyses were run at the low and high ends of these ranges for each of the key input factors. This analysis shows that the results are most sensitive to assumptions on project costs, future performance (post-refurbishment life and capability factor assumptions), future operating costs (Station Direct, Nuclear & Corporate Support costs), project costs and the discount rate.

Figure 3: Sensitivity Analysis – Darlington LUEC

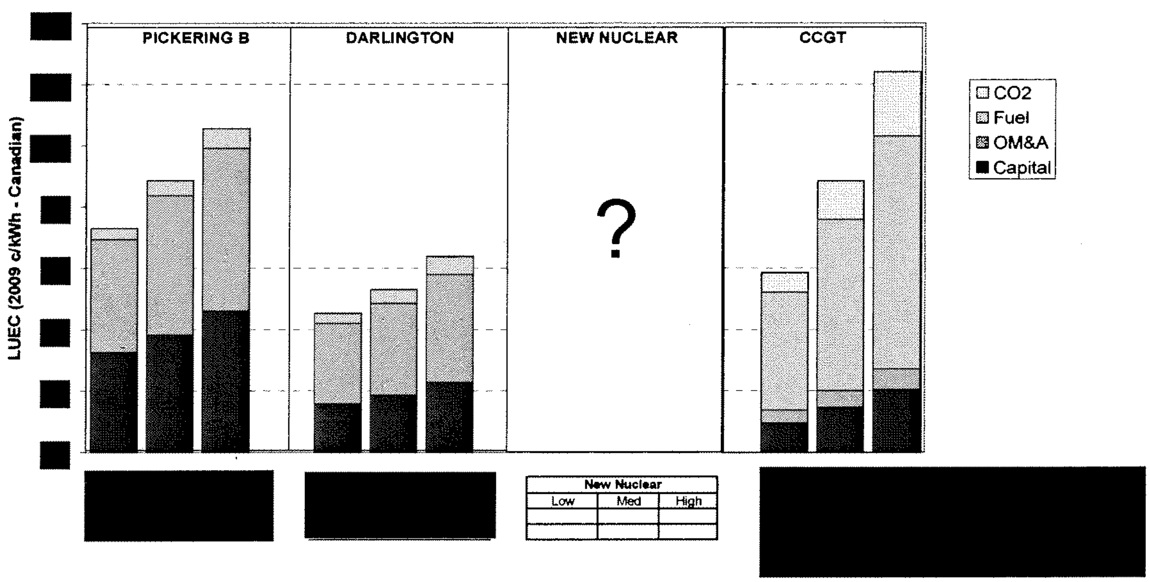


Assumptions	Lower	Base	Upper
Project Uncertainties			
Refurb Cost (2009$)	-15%	[redacted]	20%
Refurb Duration (months)	-6 mths		+12 mths
Future Performance			
ACF (%)	-5%	87%	5%
Life of Refurb Units (yrs)	+5 yrs	30 yrs	-5 yrs
Future Operating Costs			
Base OM&A ($M)	-5%	295	5%
Outage OM&A ($M)	-5%	95	10%
Sustaining Projects ($M)	-20%	100	20%
Nuclear Support ($M)	-5%	150	15%
Corporate Support ($M)	-10%	40	15%
Fuel ($/MWh)	-30%	5	30%
Discount Rate	-1%	7%	+1%
Refurb Unit Overlaps	+4 mths	19/16 mths	-4 mths
Unplanned CapEx Yr20			$1B/unit

2.3. Comparisons to Other Options

A significant input into the decision-making process on the economic viability of the Darlington Refurbishment is a comparison to the LUEC's of other options competing with this project. Figure 5 presents such a comparison.

Figure 5: Levelized Unit Energy Costs for Darlington Refurbishment and Comparators



32.

Report to Ontario Power Generation

Technology-Specific Capital Structures: An Assessment

Kathleen C. McShane
President
Foster Associates, Inc.

N. In the absence of comparable pure play publicly-traded companies, an attempt was made to identify proxy companies that could be viewed as facing reasonably comparable levels of business risk, rather than the specific business risks, faced by each of the regulated hydroelectric and nuclear operations. The costs of capital for the two samples could then be estimated and compared, with the differential in cost of capital used to estimate technology-specific capital structures.

Application of the selection criteria, which included the qualitative business risk categories assigned by Standard & Poor's to each of the regulated companies whose debt it rates, identified nine companies which could be viewed as comparable to the hydroelectric operations, but only three companies which qualified as proxies for the regulated nuclear operations. A sample of three was determined to be too small to permit robust estimates of the cost of capital which could be compared with confidence to cost of capital estimates for the hydroelectric proxy sample.

O. The qualitative assessment of the relative business risks of the hydroelectric and nuclear operations supports the conclusion that the nuclear operations face materially higher business risks than the hydroelectric operations. However, given the constraints of the available market data and the lack of proxy companies that are comparable to each of the two technologies, none of the analyses conducted were able to provide any quantitative insight into reasonable differential capital structures for the two operations. Any specification of technology-specific capital structures would be largely a judgmental exercise and lack any degree of precision. Given the degree of judgment that would be required and the absence of robust parameters upon which to base that judgment, there is no compelling basis for the Board to adopt technology-specific capital structures.

B. BUSINESS RISKS OF THE COMPOSITE PRESCRIBED ASSETS

B.1. Revenue and Market-Related Risks

Market risks for OPG are defined, in part, by the economy in which it operates. The business risk assessment conducted by Foster Associates in the latter half of 2007 concluded that, while the diversity and strength of the economy are positive for the overall business risk assessment of OPG, the challenges to the manufacturing sector expose the regulated operations to some risk of lower revenues due to decreased demand, both from cyclical declines and long-term demand destruction.

The Ontario economy generally and the manufacturing sector specifically, which accounts for a significant portion of the electricity consumed in the Province,[9] have been relatively hard hit by the global recession. The Ministry of Finance noted in its 2009 *Ontario Economic Outlook and Fiscal Review*:

> the global economic downturn hit Ontario's economy relatively hard compared to other provinces. Manufacturing, especially the auto sector, is a large and important part of Ontario's economy and it has been particularly affected by the recession. Declining U.S. demand caused Ontario auto manufacturing sales to fall by 37 per cent over the first eight months of 2009, compared to the same period in 2008. Ontario's decline in real GDP in 2009 is expected to be significantly larger than Canada's as a whole, and that of all the other provinces except Newfoundland and Labrador.

Electricity demand fell sharply in Ontario in 2009; the IESO reported in its *18-Month Outlook from December 2009 to May 2011* that energy demand dropped 5.7% in 2009. The IESO also predicted that the economic recovery is unlikely to stimulate a significant rebound in electricity demand and that, over the coming months, industrial energy demand will continue to be hampered by the high dollar and rationalization within the manufacturing sector.

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[9] T. Rosemary Yeremian, *Three Perspectives on Energy Demand and the Manufacturing Sector: The Good, the Bad and the Unanticipated*, www.strategicinsights.ca, originally published in IPPSO FACTO Magazine, 2009

The 2007 business risk assessment also pointed to low, but rising, dispatch risk creating surplus baseload generation attributed to OPG's prescribed assets, which are primarily baseload facilities. The Board's decision found that the dispatch risks, described as the risk that baseload generation from OPG's regulated assets will not be dispatched because of economic conditions and/or the presence of generators with lower marginal costs, are low.

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.

B.2. Production, Operating and Cost Recovery Risks

Production, operating and cost recovery risks include all factors that may result in OPG under recovering a reasonable return on investment and/or a part of the investment itself due to higher than anticipated costs of production, lower than anticipated production or loss of production. As the production, operating and cost recovery risks are largely specific to the generation technology, they are discussed as applicable in the individual hydroelectric and nuclear operations sections below.

C. BUSINESS RISKS OF THE HYDROELECTRIC OPERATIONS

C.1. Revenue and Market-Related Risks

The key revenue risks identified in the 2007 business risk assessment for the hydroelectric operations were the structure of the regulated payments (100% energy based) as compared to the largely fixed cost structure and the dispatch risk, resulting in surplus baseload generation from OPG's prescribed hydroelectric assets, which was assessed as low but rising. With respect to the latter, rising dispatch risk is supported, as noted above, by the passage of the Green Energy and Green Economy Act and low demand conditions. The risk that OPG's regulated baseload facilities will not be dispatched is higher for the hydroelectric operations, as the nuclear production facilities are not designed to ramp up and down, while hydroelectric production can be curtailed by spilling water at the generation facilities.

C.2. Changes in Business Risk since EB-2007-0905

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.

D. BUSINESS RISKS OF THE REGULATED NUCLEAR OPERATIONS

D.1. Revenue and Market-Related Risks

As with the hydroelectric operations, revenue risks of the regulated nuclear operations are partly a function of the payment structure in relation to the cost structure. The cost structure of the nuclear operations is largely fixed, i.e., do not vary directly with changes in production. In EB-2007-0905, OPG proposed a payment structure for the regulated nuclear operations that would recover 25% of the forecast nuclear revenue requirement in a fixed charge. The 2007 business risk assessment was premised on the implementation of the proposed fixed charge, which would have reduced the regulated nuclear operations' revenue risks.

The Board declined to approve OPG's proposed payment structure, instead adopting a 100% energy-based regulated payment. The Board concluded that OPG should be fully incented to produce as accurate a forecast of nuclear production as possible and should be at risk if actual output falls short of forecast. The adoption of a 100% energy-based regulated payment in lieu of a payment that partially recovers the revenue requirement in a fixed charge results in higher revenue risk to the regulated nuclear operations than anticipated in the 2007 business risk assessment and increases the business risk of OPG's nuclear operations relative to that of the hydroelectric operations.

The regulated nuclear operations are, like the regulated hydroelectric operations, facing somewhat higher dispatch risk as a result of the passage of the Green Energy and Green Economy Act and low demand conditions. However, as nuclear generating plants are generally less amenable to ramping up and down in times of increased or decreased demand than hydroelectric generating plants, the dispatch risk attached to surplus baseload generation remains lower for the nuclear operations than for the regulated hydroelectric operations.

D.2. Production, Operating and Cost Recovery Risks

The 2007 business risk assessment concluded that the production/operating risks related to the nuclear assets are significantly higher than those of the hydroelectric generation facilities and higher than those of any other type of generation. Specifically, nuclear technology is more complex than other types of generation and is subject to higher risks of unanticipated costs of repair and loss of production. While the forecast costs and production from the nuclear facilities include a provision for both planned and unplanned a calculation of the historical correlation between the overall equity market, as proxied in Canada by the S&P/TSX Composite, and individual stocks or portfolios of stocks.

Non-diversifiable risks include factors to which all stocks are sensitive in some measure, e.g., inflation, interest rates, economic growth, and oil prices. The sensitivity of specific industries to these factors would be a function of fundamental characteristics industries that are correlated with non-diversifiable risks. For example, stock prices of financial service companies would be sensitive to changes in interest rates; stock prices of oil and gas producers would be sensitive to changes in energy prices; stock prices of manufacturing companies would be sensitive to the ups and downs of the business cycle. For individual stocks, firm-specific characteristics that are correlated with the market-wide factors would influence the sensitivity of those companies' stock prices to market-wide events, muting or magnifying the impacts. For example, the assumption of leverage increases the volatility of a company's earnings stream. All other things equal, higher leverage would magnify the sensitivity of a company's share price to market-wide factors, i.e., increase the beta.

However, the CAPM posits that firm-specific characteristics that are not correlated with market-wide factors are diversifiable and not priced by the capital market. Examples of firm-specific risks that are diversifiable include the impacts of weather, labour strikes, loss of a key customer account (unrelated to macroeconomic factors), system security risks, or changes in government regulations specific to one industry.

In the case of OPG, a key factor that distinguishes the regulated nuclear operations from the regulated hydroelectric operations is operating risks, which in principle should be diversifiable. Consequently, the ability of methodologies derived from the CAPM to capture the difference in risk between the two technologies is, *a priori*, questionable.

Even if one were to accept that, in principle, betas would capture the risks that distinguish the two technologies, there are at least two other factors that call into question the ability of CAPM derived models to accurately capture differences in risk and allow an accurate assessment of the differences in return requirement between the two technologies. These two factors are (1) the instability of measured betas from one time period to the next; and (2) differences in calculated betas depending on the manner in which they are measured.

With respect to the first issue, betas are typically measured over five-year horizons. To illustrate how variable betas can be, even for portfolios of stocks, Schedule 1 sets out betas for the 10 major sectors of the S&P/TSX Composite for the five-year periods ending 1997 to 2008. Schedule 1 shows, for example, that the "raw" five-year betas for the financial sector during that time period ranged from 0.38 to 1.12; betas for the energy sector ranged from 0.17 to 1.44; the range for the utilities sector was -0.25 to 0.55. Schedule 2 sets out adjusted[27] *Value Line* betas for a sample of 28 U.S. electric utilities from 1997 to 2009.[28] Schedule 2 demonstrates that, even when adjusted toward the market mean of 1.0, thus smoothing the period to period fluctuations, the average betas for the sample have ranged from 0.50 to 0.95. 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.

With respect to differences in calculated betas, there can be significant differences in measured betas depending on the interval over which the change in share price is calculated. Betas calculated using monthly changes in price can differ systematically from betas calculated using weekly changes in prices. There is no "rule" for choosing monthly intervals versus weekly intervals for calculating betas. The principal benefit of weekly betas is the increased number of observations, which mitigates the impact of outlier observations on the measured beta. The benefit of monthly betas is the potential mitigation of non-synchronous trading, which largely affects stocks that are traded

[27] *Value Line* adjusts the "raw" betas toward the market mean beta of 1.0 using a formula which gives two-thirds weight to the "raw" beta and one-third weight to the market mean beta of 1.0. The use of the term adjusted beta throughout this report refers to "raw" betas that have been adjusted to the market mean of 1.0 using these weightings.
[28] The 28 electric utilities represent a sample of utilities with more than one-third of their assets devoted to generation which are used later in the report to attempt to isolate the incremental risk and return requirement associated with electricity generation operations. The selection criteria are described in Appendix A.

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X. DEBT RATING AGENCY GUIDELINES AND TECHNOLOGY-SPECIFIC CAPITAL STRUCTURES

As the empirical methodologies described and applied in the above section provided little perspective on the relative cost of capital and capital structures for OPG's regulated hydroelectric and nuclear operations, more subjective approaches were considered. The debt rating guidelines for regulated company capital structures relied on by Standard & Poor's ("S&P") and Moody's were identified as a potential means of establishing technology-specific capital structures on the basis of differences in business risk.[40]

S&P publishes a matrix of debt rating guidelines that apply to all corporate debt issuers including regulated utilities and power companies. The matrix includes six business risk categories, ranging from "Excellent" to "Vulnerable". Most regulated Canadian companies rated by S&P are in the "Excellent" category. The other categories are "Strong", "Satisfactory", "Fair" and "Weak". In assigning business risk categories to regulated companies, S&P evaluates qualitative factors including regulation, markets, operations, competitiveness and management, with regulation being a critical aspect of utilities' creditworthiness.

The business risk assessment is accompanied by a financial risk assessment. The financial risk assessment includes, but is not limited to, the consideration of three key quantitative credit metrics which include Total Debt/Total Capital. For each of the three metrics, S&P publishes a guideline range associated with six financial risk categories. The lowest financial risk category is "Minimal"; the highest financial risk category is "Highly Leveraged". The table below presents the guideline Total Debt/Capital ranges for each financial risk category. S&P notes that the guideline ranges are intended to represent the level of ranges that have been achieved historically and are expected to consistently continue.

[40] DBRS has published guidelines that do not distinguish by either business risk or investment grade rating category.

Table 2

Financial Risk Profile	Total Debt/Capital (%)
Minimal	Less than 25%
Modest	25-35
Intermediate	35-45
Significant	45-50
Aggressive	50-60
Highly leveraged	Over 60

Source: Standard & Poor's, *Ratings Methodology: Business Risk/Financial Risk Matrix Expanded*, May 27, 2009.

The business and financial risk categories are combined to create a matrix which shows the likely debt rating with a given business risk and financial risk profile, as shown in the table below. For example, a business risk profile of "Excellent" and a financial risk profile of "Significant" correspond to a rating of A-. The indicated range of debt ratios for a "Significant" financial risk profile is 45-50% (corresponding equity ratios of 50-55%). With a "Satisfactory" business risk profile, to achieve the same A- debt rating, the guidelines indicate a financial risk profile of "Minimal", which is associated with a debt ratio below 25% (or equity ratio in excess of 75%).

Table 3

	Financial Risk Profile					
Business Risk Profile	**Minimal**	**Modest**	**Intermediate**	**Significant**	**Aggressive**	**Highly Leveraged**
Excellent	AAA	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	CCC+

Source: Standard & Poor's, *Ratings Methodology: Business Risk/Financial Risk Matrix Expanded*, May 27, 2009.

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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. First, the guidelines govern all industries, not specifically regulated companies, which means that the application of the S&P guidelines to regulated companies generally entails considerable judgment. Second, the determination of the business risk category that S&P would hypothetically assign to each of the hydroelectric and nuclear operations on a stand-alone basis requires further judgment. Third, for a given debt rating, the effect of diversification, while not quantifiable, would permit a lower common equity ratio to be maintained for the composite regulated operations than for the regulated operations on a true stand-alone basis. Fourth, there is no direct connection between the debt rating guidelines and the cost of equity.

The specification of capital structures which equate the costs of equity of the nuclear and hydroelectric operations is the underlying premise of the Board's approach. The adoption of technology-specific capital structures within the debt ratio ranges indicated for given business risk categories would not allow the conclusion to be drawn that the costs of equity were the same for the individual operations.

Moody's has recently revised its ratings guidelines for electric and gas utilities.[41] The Moody's guidelines entail assigning an implied debt rating to each of four factors, regulatory framework, ability to recover costs and earn returns, diversification and financial strength. Each of the factor (and thus implied rating on each of those factors) is assigned a weight. The three business risk factors are assigned a total weight of 60%; financial strength is assigned a weight of 40%. The financial risk factor is further broken down into four quantitative guidelines, including the debt ratio.[42] The debt ratio is assigned 7.5% weight in the determination of the overall debt rating. The weighted

[41] Moody's, *Rating Methodology: Regulated Electric and Gas Utilities*, August 2009.
[42] For example, a debt ratio range of 35%-45% is associated with an A rating; a debt ratio range of 45%-55% is associated with a Baa rating.

average implied rating should be similar to the actual rating (i.e., within one notch) that Moody's assigns.

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 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. Cost of equity studies are required to address differences in equity return requirements; see Chapter XI below.

5-YEAR PRICE BETAS FOR S&P/TSX SECTOR INDICES

	Consumer Discretionary	Consumer Staples	Energy	Financials	Health Care
1997	0.82	0.62	0.97	0.94	0.60
1998	0.80	0.60	0.85	1.12	1.01
1999	0.73	0.44	0.90	1.00	1.00
2000	0.69	0.23	0.66	0.78	1.09
2001	0.68	0.10	0.49	0.66	0.98
2002	0.73	0.08	0.43	0.66	0.99
2003	0.74	-0.08	0.26	0.38	0.85
2004	0.80	-0.07	0.17	0.39	0.82
2005	0.83	0.07	0.48	0.56	0.72
2006	0.86	0.37	1.03	0.68	0.85
2007	0.73	0.54	1.44	0.51	0.54
2008	0.59	0.32	1.43	0.61	0.48

	Industrials	Information Technology	Materials	Telecommunication Services	Utilities
1997	0.97	1.57	1.32	0.64	0.53
1998	0.93	1.41	1.12	0.92	0.55
1999	0.78	1.55	1.04	1.11	0.30
2000	0.72	1.78	0.74	0.92	0.14
2001	0.82	2.13	0.60	0.94	-0.03
2002	0.86	2.28	0.57	0.93	-0.06
2003	0.91	2.74	0.43	0.83	-0.25
2004	1.05	2.87	0.41	0.58	-0.13
2005	1.13	2.68	0.77	0.74	0.00
2006	1.06	2.07	1.32	0.52	0.25
2007	0.96	1.12	1.45	0.62	0.46
2008	0.81	1.43	1.30	0.55	0.49

Source: TSX Review

HISTORIC VALUE LINE BETAS FOR
HIGH GENERATION U.S. ELECTRIC UTILITY SAMPLE

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
ALLEGHENY ENERGY	0.75	0.70	0.60	0.60	0.60	1.15	1.45	1.60	1.80	2.10	1.40	1.10	0.95
ALLETE INC	0.70	0.60	0.45	0.50	0.45	0.60	0.70	nmf	nmf	0.90	0.95	0.75	0.70
ALLIANT ENERGY CORP	0.55	nmf	nmf	0.55	0.55	0.65	0.70	0.80	0.85	0.95	0.80	0.70	0.70
AMEREN CORP	0.70	0.65	0.50	0.55	0.55	0.60	0.65	0.75	0.75	0.75	0.80	0.80	0.80
AMERICAN ELECTRIC POWER CO	0.70	0.65	0.45	0.55	0.55	0.75	0.95	1.15	1.20	1.35	0.95	0.75	0.70
AVISTA CORP	0.70	0.70	0.50	0.55	0.60	0.65	0.75	0.85	0.90	0.95	1.00	0.85	0.70
CONSTELLATION ENERGY	0.80	0.60	0.55	0.55	0.60	0.75	0.85	0.85	0.95	0.95	0.85	0.75	0.80
DOMINION RESOURCES	0.70	0.55	0.50	0.55	0.50	0.75	0.80	0.85	0.90	1.00	0.75	0.70	0.70
DPL INC	0.75	0.70	0.55	0.55	0.60	0.75	0.80	0.90	1.00	0.95	0.85	0.65	0.60
DTE ENERGY CO	0.80	0.75	0.60	0.60	0.55	0.60	0.60	0.70	0.70	0.75	0.80	0.70	0.75
EMPIRE DISTRICT	0.60	0.60	0.45	0.50	0.45	0.50	0.60	0.70	0.70	0.80	0.85	0.75	0.75
ENTERGY CORP	0.80	0.70	0.50	0.60	0.50	0.60	0.65	0.75	0.80	0.85	0.85	0.75	0.70
EXELON CORP	na	na	na	nmf	nmf	0.70	0.70	0.70	0.75	0.90	0.90	0.90	0.85
FIRSTENERGY CORP	0.80	0.70	0.50	0.55	0.55	0.55	0.75	0.75	0.75	0.80	0.85	0.85	0.80
FPL GROUP	0.75	0.55	0.50	0.45	0.45	0.55	0.65	0.70	0.75	0.85	0.75	0.80	0.75
GREAT PLAINS ENERGY INC	0.75	0.60	0.60	0.60	0.55	0.65	0.70	0.80	0.85	0.95	0.80	0.65	0.75
IDACORP INC	0.70	0.65	0.50	0.50	0.50	0.60	0.75	0.85	0.95	1.00	1.00	0.85	0.70
MGE ENERGY	0.50	0.50	0.50	0.45	0.45	0.50	0.55	0.60	0.70	0.75	0.95	0.70	0.65
PINNACLE WEST CAPITAL CORP	0.75	0.70	0.45	0.45	0.45	0.55	0.70	0.85	0.90	1.00	1.00	0.75	0.75
PPL CORP	0.70	0.55	0.55	0.60	0.70	0.80	0.90	0.95	1.00	0.95	0.90	0.80	0.70
PROGRESS ENERGY INC	0.65	0.50	0.45	0.45	nmf	nmf	0.80	0.80	0.85	0.90	0.85	0.60	0.65
PUBLIC SERVICE ENTRP GRP INC	0.75	0.55	0.50	0.55	0.55	0.70	0.80	0.85	0.90	1.00	0.95	0.85	0.80
SCANA CORP	0.70	0.55	0.45	0.45	0.45	0.55	0.65	0.70	0.75	0.85	0.85	0.70	0.65
SOUTHERN CO	0.70	0.50	0.45	0.50	nmf	nmf	0.60	0.65	0.65	0.70	0.70	0.55	0.55
TECO ENERGY INC	0.70	0.55	0.50	0.50	0.50	0.70	0.80	0.90	0.95	1.05	0.95	0.75	0.85
WESTAR ENERGY INC	0.65	0.55	0.35	0.30	0.35	0.50	0.60	0.75	0.85	0.90	0.85	0.80	0.75
WISCONSIN ENERGY CORP	0.70	0.65	0.45	0.50	0.50	0.55	0.60	0.70	0.70	0.80	0.85	0.65	0.65
XCEL ENERGY INC	na	na	na	nmf	nmf	0.60	0.70	0.80	0.80	0.90	1.05	0.75	0.65
MEAN	**0.71**	**0.61**	**0.50**	**0.52**	**0.52**	**0.65**	**0.74**	**0.82**	**0.88**	**0.95**	**0.89**	**0.76**	**0.73**
MEDIAN	**0.70**	**0.60**	**0.50**	**0.55**	**0.53**	**0.60**	**0.70**	**0.80**	**0.85**	**0.90**	**0.85**	**0.75**	**0.70**

Source: *Value Line*, 4th Quarter issues and Issues 1, 5, and 11 3rd Quarter of 2009

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INDIVIDUAL COMPANY RISK DATA FOR 44 U.S. ELECTRIC UTILITIES USED IN THE INSTRUMENTAL VARIABLES ANALYSIS

	Percent of Total Assets												
	Generation	Wires	Other	Nuclear % Capacity	Nuclear Assets % of Total Assets 1/	Hydro Assets % of Total Assets 1/	Adjusted 5 Year Betas Ending October 2009 2/	Common Equity Ratio 2008	S&P Debt Rating 3/	S&P Business Profile	S&P Financial Profile	Moody's Debt Rating 3/	Value Line Safety Rank
Allegheny Energy	53.1%	46.9%	0.0%	0.0%	0.0%	6.7%	0.98	40%	BBB-	Strong	Aggressive	Ba1	3
ALLETE	54.4%	35.7%	9.9%	0.0%	0.0%	4.5%	0.75	58%	BBB+	Strong	Significant	A2	2
Alliant Energy	33.7%	53.6%	12.6%	0.0%	0.0%	0.2%	0.83	56%	BBB+	Excellent	Significant	Baa1	2
Ameren Corp.	58.3%	36.7%	5.0%	7.5%	4.4%	1.3%	0.90	46%	BBB-	Satisfactory	Significant	Baa3	3
American Electric Power	42.0%	55.8%	2.2%	6.0%	2.5%	0.8%	0.83	37%	BBB	Excellent	Aggressive	Baa2	3
Avista Corp.	38.0%	56.6%	5.4%	0.0%	0.0%	21.2%	0.77	46%	BBB-	Excellent	Aggressive	Baa3	3
Black Hills Corp.	27.2%	47.2%	25.6%	0.0%	0.0%	0.0%	0.89	47%	BBB-	Satisfactory	Significant	Baa3	3
Centerpoint Energy	0.0%	96.6%	3.4%	0.0%	0.0%	0.0%	0.97	16%	BBB	Excellent	Aggressive	Ba1	3
CH Energy Group	2.1%	84.1%	13.8%	0.0%	0.0%	0.0%	0.78	52%	A	Excellent	Intermediate	A3	1
Cleco Corp.	21.2%	78.8%	0.0%	0.0%	0.0%	0.0%	0.77	48%	BBB	Excellent	Aggressive	Baa3	3
Consolidated Edison	4.5%	95.5%	0.0%	0.0%	0.0%	0.0%	0.66	48%	A-	Excellent	Significant	Baa1	1
Constellation Energy	69.7%	30.3%	0.0%	42.8%	29.8%	2.2%	0.80	27%	BBB	Satisfactory	Significant	Baa3	3
Dominion Resources	47.1%	45.4%	7.5%	21.6%	10.2%	3.7%	0.75	36%	A-	Excellent	Significant	Baa2	2
DPL Inc.	68.1%	31.3%	0.6%	0.0%	0.0%	0.0%	0.69	38%	A-	Excellent	Intermediate	Baa1	3
DTE Energy	37.7%	53.3%	9.0%	9.5%	3.6%	2.9%	0.85	40%	BBB	Strong	Significant	Baa2	3
Edison International	29.7%	63.4%	6.9%	17.0%	5.1%	2.5%	0.92	40%	BBB-	Strong	Aggressive	Baa2	3
Empire District Electric	38.8%	60.0%	1.2%	0.0%	0.0%	0.5%	0.76	42%	BBB-	Excellent	Aggressive	Baa2	3
Entergy Corp.	54.3%	44.3%	1.3%	33.3%	18.1%	0.1%	0.73	39%	BBB	Strong	Significant	Baa3	2
Exelon Corp.	41.7%	58.3%	0.0%	67.3%	28.1%	2.7%	0.94	45%	BBB	Strong	Significant	Baa1	1
FirstEnergy Corp.	37.7%	62.3%	0.0%	29.2%	11.0%	1.8%	0.83	37%	BBB	Strong	Significant	Baa3	2
FPL Group	53.9%	37.7%	8.4%	13.8%	7.4%	0.5%	0.82	41%	A	Excellent	Intermediate	A2	1
Great Plains Energy	49.6%	50.4%	0.0%	9.2%	4.6%	0.0%	0.84	44%	BBB	Excellent	Aggressive	Baa3	3
Hawaiian Electric Industries	11.7%	29.8%	58.5%	0.0%	0.0%	0.0%	0.78	42%	BBB	Strong	Significant	Baa2	3
IDACORP, Inc.	43.1%	49.5%	7.4%	0.0%	0.0%	23.0%	0.75	48%	BBB	Excellent	Aggressive	Baa2	3
Integrys Energy Group	14.0%	48.2%	37.9%	0.0%	0.0%	0.5%	0.88	46%	BBB+	Excellent	Aggressive	Baa1	3
MGE Energy	41.3%	58.7%	0.0%	0.0%	0.0%	0.0%	0.71	55%	AA-	Excellent	Intermediate	Aa3	1
Northeast Utilities	3.8%	95.5%	0.6%	0.0%	0.0%	0.2%	0.74	35%	BBB	Excellent	Aggressive	Baa2	3
NSTAR	0.1%	97.5%	2.4%	0.0%	0.0%	0.0%	0.70	37%	A+	Excellent	Intermediate	A2	1
OGE Energy	24.1%	61.0%	14.9%	0.0%	0.0%	0.0%	0.88	44%	BBB+	Strong	Significant	Baa1	2
Otter Tail Corp.	31.4%	28.8%	39.8%	0.0%	0.0%	0.2%	1.05	58%	BBB-	Satisfactory	Significant	Ba1	2
Pepco Holdings	19.4%	70.6%	10.0%	0.0%	0.0%	0.0%	1.01	41%	BBB	Strong	Significant	Baa3	3
PG&E Corp.	10.6%	89.4%	0.0%	33.0%	3.5%	6.0%	0.67	44%	BBB+	Excellent	Significant	Baa1	2
Pinnacle West Capital	38.6%	55.7%	5.8%	17.9%	6.9%	0.0%	0.81	47%	BBB-	Strong	Significant	Baa3	3
PPL Corp.	56.0%	44.0%	0.0%	19.4%	10.8%	4.6%	0.82	37%	BBB	Satisfactory	Significant	Baa2	3
Progress Energy	45.5%	54.5%	0.0%	16.6%	7.5%	0.5%	0.71	42%	BBB+	Excellent	Aggressive	Baa2	2
Public Service Enterprise Group	45.5%	54.5%	0.0%	22.6%	10.3%	0.6%	0.80	46%	BBB	Strong	Significant	Baa2	3
SCANA Corp.	36.9%	50.1%	13.0%	11.1%	4.1%	5.1%	0.74	39%	BBB+	Excellent	Aggressive	Baa2	2
Sempra Energy	11.8%	70.1%	18.1%	14.3%	1.7%	0.0%	0.86	51%	BBB+	Strong	Intermediate	Baa1	2
Southern Co.	50.0%	47.2%	2.9%	8.3%	4.2%	3.2%	0.60	41%	A	Excellent	Intermediate	A3	1
TECO Energy	51.9%	43.7%	4.3%	0.0%	0.0%	0.0%	0.83	38%	BBB	Excellent	Aggressive	Baa3	3
Vectren Corp.	18.9%	60.5%	20.6%	0.0%	0.0%	0.0%	0.76	42%	A-	Excellent	Significant	Baa1	2
Westar Energy	60.0%	40.0%	0.0%	7.9%	4.8%	0.0%	0.82	45%	BBB-	Excellent	Aggressive	Baa1	2
Wisconsin Energy	54.0%	46.0%	0.0%	0.0%	0.0%	0.8%	0.67	41%	BBB+	Excellent	Aggressive	A3	2
Xcel Energy	33.5%	61.1%	5.4%	9.9%	3.3%	1.2%	0.68	44%	BBB+	Excellent	Significant	Baa1	2
Mean	**35.6%**	**56.4%**	**8.1%**	**9.5%**	**4.1%**	**2.2%**	**0.80**	**42.8%**	**BBB+**	**Strong**	**Significant**	**Baa2**	**2**
Median	**38.3%**	**54.0%**	**3.9%**	**0.0%**	**0.0%**	**0.5%**	**0.80**	**42.1%**	**BBB**	**Excellent**	**Significant**	**Baa2**	**3**

1/ Nuclear Assets % of Total Assets = Total Generation % * Nuclear % Capacity; Hydro Assets % of Total Assets = Total Generation % * Hydro % Capacity

2/ Calculated using weekly data against the S&P 500 (260 weeks ending October 2009); adjusted towards the market mean of 1.0.

3/ Rating of CH Energy Group for Central Hudson Gas and Electric; Rating of MGE Energy for Madison Gas and Electric

Source: Company Form 1s and 10-ks; S&P Research Insight; www.yahoo.com; *Value Line Investment Survey* Index December 18, 2009; www.moodys.com
Standard and Poor's, *Issuer Ranking: U.S. Regulated Electric Utilities, Strongest to Weakest* (November 11, 2009).
Standard and Poor's, *Issuer Ranking: U.S. Integrated Utility And Merchant Power Companies, Strongest to Weakest* (November 5, 2009).
Standard and Poor's, *Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest* (November 5, 2009).

INDIVIDUAL COMPANY REGRESSION DATA FOR 44 U.S. ELECTRIC UTILITIES USED IN THE INSTRUMENTAL VARIABLE ANALYSIS

	5 Year Research Insight Unadjusted Beta 2008	10 Year Research Insight Unadjusted Beta 2008	10 Year Standard Deviation of ROE	10 Year ROE Beta 2008	5 Year Dividend Payout	10 Year Dividend Payout	5 Year Average Market Value ($ Million)	10 Year Average Market Value ($ Million)	5 Year Average Debt/Total Capital	10 Year Average Debt/Total Capital	5 Year Average Annual Asset Growth	10 Year Average Annual Asset Growth	Nuclear % Capacity	S&P Rating Score
Allegheny Energy	0.96	0.80	18.03	0.00	0.09	0.57	6,366	4,724	66.4%	66.7%	1.2%	4.8%	0.0%	7
ALLETE	0.72	0.43	4.41	-0.11	0.82	0.73	1,220	1,593	38.8%	46.2%	-7.2%	-0.3%	0.0%	5
Alliant Energy	0.59	0.36	5.28	0.07	0.51	0.62	3,737	3,037	41.6%	47.6%	1.1%	5.2%	0.0%	5
Ameren Corp.	0.72	0.31	2.21	0.05	0.88	0.86	9,946	8,032	50.0%	49.3%	9.7%	9.9%	7.5%	7
American Electric Power	0.72	0.43	6.08	0.00	0.53	0.80	15,449	13,379	60.4%	62.7%	4.2%	8.8%	6.0%	6
Avista Corp.	0.69	0.38	3.33	0.11	0.56	0.54	1,048	882	57.2%	57.9%	-0.2%	1.1%	0.0%	7
Black Hills Corp.	1.05	0.62	5.71	-0.12	1.07	0.73	1,217	1,016	49.8%	53.9%	10.4%	19.7%	0.0%	7
Centerpoint Energy	0.83	0.65	37.42	2.68	0.52	0.43	4,514	5,567	85.9%	77.7%	-1.6%	0.3%	0.0%	6
CH Energy Group	0.35	0.22	1.17	0.12	0.82	0.79	765	731	43.0%	41.9%	5.9%	2.8%	0.0%	3
Cleco Corp.	0.67	0.60	8.84	0.21	0.43	0.56	1,308	1,098	48.4%	55.6%	9.1%	8.9%	0.0%	6
Consolidated Edison	0.25	0.00	1.62	-0.20	0.75	0.75	11,659	10,127	50.8%	50.2%	9.8%	8.8%	0.0%	4
Constellation Energy	0.94	0.58	14.37	2.45	0.98	0.73	10,740	8,033	54.9%	55.0%	7.1%	9.3%	42.8%	6
Dominion Resources	0.50	0.34	6.14	-0.46	0.58	0.67	25,471	20,470	61.7%	62.2%	-1.0%	9.2%	21.6%	4
DPL Inc.	0.61	0.50	5.84	-0.37	0.59	0.64	3,026	2,890	64.9%	65.6%	-3.7%	-0.5%	0.0%	4
DTE Energy	0.59	0.20	3.00	0.05	0.65	0.66	7,352	6,807	60.0%	60.7%	3.5%	7.4%	9.5%	6
Edison International	0.80	0.36	23.35	-1.96	0.37	0.32	13,463	9,742	56.0%	68.0%	5.0%	6.1%	17.0%	7
Empire Distric Electric	0.68	0.26	1.78	0.13	1.16	1.15	645	545	53.9%	55.6%	11.2%	10.1%	0.0%	7
Entergy Corp.	0.70	0.22	2.71	-0.15	0.45	0.45	17,287	13,373	54.4%	52.7%	5.1%	4.8%	33.3%	6
Exelon Corp.	0.71	0.31	6.36	-0.57	0.56	0.51	39,339	27,960	57.3%	61.7%	2.7%	14.8%	67.3%	6
FirstEnergy Corp.	0.60	0.27	3.33	-0.10	0.55	0.58	17,060	12,949	57.1%	59.0%	0.4%	6.4%	29.2%	6
FPL Group	0.61	0.35	1.13	-0.07	0.50	0.50	20,116	15,380	56.7%	54.2%	10.7%	14.1%	13.8%	3
Great Plains Energy	0.66	0.57	6.29	0.65	0.93	1.03	2,346	2,014	51.5%	54.7%	16.5%	10.1%	9.2%	6
Hawaiian Electric Industries	0.26	0.13	2.15	0.07	0.98	0.92	2,113	1,757	68.6%	72.6%	0.0%	1.2%	0.0%	6
IDACORP, Inc.	0.37	0.34	4.08	0.11	0.61	0.68	1,439	1,366	51.9%	52.9%	5.3%	5.1%	0.0%	6
Integrys Energy Group	0.48	0.21	2.91	0.32	0.85	0.80	2,729	1,938	50.6%	51.2%	27.2%	25.2%	0.0%	5
MGE Energy	0.26	0.16	1.31	-0.04	0.69	0.74	746	593	45.4%	46.9%	11.9%	10.5%	0.0%	1
Northeast Utilities	0.68	0.50	7.50	-0.44	1.02	0.62	3,679	3,140	62.4%	63.0%	4.3%	3.0%	0.0%	6
NSTAR	0.34	0.26	4.23	0.30	0.64	0.72	3,479	2,932	63.5%	62.8%	5.5%	9.9%	0.0%	2
OGE Energy	0.75	0.37	2.68	0.38	0.60	0.70	2,841	2,288	51.8%	56.7%	7.3%	8.1%	0.0%	5
Otter Tail Corp.	1.20	0.43	3.56	0.33	0.73	0.68	874	757	40.3%	41.9%	11.4%	9.9%	0.0%	7
Pepco Holdings	0.78	0.40	3.93	0.28	0.66	0.70	4,604	3,755	59.9%	61.7%	4.2%	9.5%	0.0%	6
PG&E Corp.	0.50	0.40	34.83	-1.02	0.22	0.41	14,291	10,929	55.0%	60.5%	6.3%	2.1%	33.0%	5
Pinnacle West Capital	0.57	0.36	2.90	0.13	0.76	0.62	4,149	3,769	50.4%	51.9%	4.0%	5.5%	17.9%	7
PPL Corp.	0.62	0.58	5.98	0.71	0.48	0.46	13,198	9,445	60.7%	66.8%	4.6%	8.3%	19.4%	6
Progress Energy	0.49	0.24	1.87	0.05	0.88	0.83	11,584	10,421	56.0%	57.7%	2.7%	13.6%	16.6%	5
Public Service Enterprise Group	0.68	0.39	3.60	-0.05	0.62	0.64	17,031	12,906	62.8%	66.7%	0.7%	4.9%	22.6%	6
SCANA Corp.	0.61	0.32	5.36	-0.29	0.62	0.57	4,572	3,888	56.7%	57.3%	6.4%	8.1%	11.1%	5
Sempra Energy	0.77	0.38	3.25	0.01	0.29	0.35	12,267	8,683	46.1%	51.1%	3.7%	9.7%	14.3%	5
Southern Co.	0.37	-0.16	1.06	0.02	0.71	0.73	27,269	23,491	56.2%	58.0%	6.6%	2.9%	8.3%	3
TECO Energy	0.78	0.43	23.71	-0.55	1.30	1.03	3,302	3,204	68.0%	66.0%	-7.3%	5.5%	0.0%	6
Vectren Corp.	0.24	0.31	1.86	0.16	0.75	0.75	2,098	1,771	58.3%	58.8%	6.7%	20.6%	0.0%	4
Westar Energy	0.60	0.68	8.16	0.64	0.62	1.21	2,160	1,708	54.0%	62.8%	5.4%	-0.7%	7.9%	7
Wisconsin Energy	0.45	0.11	1.60	0.05	0.38	0.49	4,934	3,912	59.0%	61.5%	4.7%	8.9%	0.0%	5
Xcel Energy	0.56	0.56	16.36	1.05	0.65	1.19	8,445	7,592	56.2%	62.3%	4.3%	12.9%	9.9%	5
Mean	**0.62**	**0.37**	**7.07**	**0.11**	**0.67**	**0.69**	**8,224**	**6,605**	**55.8%**	**58.0%**	**5.1%**	**7.9%**	**9.5%**	**5**
Median	**0.61**	**0.36**	**4.00**	**0.05**	**0.63**	**0.68**	**4,543**	**3,828**	**56.1%**	**57.9%**	**4.9%**	**8.2%**	**0.0%**	**6**

Source: Company Form 1s and 10-ks, S&P Research Insight

Numbers may not add due to rounding.

Table 1
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital ($M)
Calendar Year Ending December 31, 2012

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	189.5	2.9%	4.13%	10.4
2	**Existing/Planned Long-Term Debt**	2	2,502.8	38.8%	5.50%	137.6
3	**Other Long-Term Debt Provision**	3	725.2	11.2%	5.87%	42.6
4	**Total Debt**	4	3,417.5	53.0%	5.58%	190.6
5	**Common Equity**	4	3,030.6	47.0%	9.85%	298.5
6	**Rate Base Financed by Capital Structure**	5	6,448.1	81.2%	7.59%	489.1
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,490.1	18.8%	5.58%	83.1
8	**Rate Base**	7	7,938.2	100%	7.21%	572.2

Notes:

1 Short Term Financing allocated at: 64.7%
Short-term Debt Cost includes interest at the cost rate shown plus an allocation of the credit facility cost shown at Ex. C1-T1-S3 Table 2, line 10.

2 Ex. C1-T1-S2 Table 7 (line 43).

3 Debt required to balance capital structure with proposed rate base. See Ex. C1-T1-S2 Section 5.0.

4 Capital Structure and Return on Equity approved by the OEB in EB-2007-0905 as discussed in Ex. C1-T1-S1.

5 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from C2-T1-S2 Table 1, line 29. Cost Rate from Ex. C2-T1-S2, Section 4.1.

7 Ex. B1-T1-S1 Table 1 (Regulated Hydroelectric) and Ex. B1-T1-S1 Table 2 (Nuclear).

Pollution Probe Interrogatory #031

Ref: Ex. C3-T1-S1, page 24

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

Interrogatory

Ms. McShane states here that: "The Ontario economy generally and the manufacturing sector specifically, which accounts for a significant portion of the electricity consumed in the Province, have been relatively hard hit by the global recession." The text goes on to quote the 2009 *Ontario Economic and Outlook and Fiscal Review.*

Does this forecast require any updating to be applicable to the test period? If so, please provide all updates applicable for the test period that Ms. McShane deems relevant.

Response

The purpose of the statement from Ms. McShane's report referenced in the question was to provide an illustration of the statement from Ms. McShane's EB-2007-0905 testimony that appears in the preceding paragraph, i.e., "While the diversity and strength of the economy are positive for the overall business risk assessment of OPG, the challenges to the manufacturing sector expose the regulated operations to some risk of lower revenues due to decreased demand, both from cyclical declines and long-term demand destruction." That statement from EB-2007-0905 was in the context of longer-term challenges to the Ontario economy. The relevant update to the referenced section of Ex. C3-T1-S1 is the IESO's forecast of electricity demand.

The most recent (May 2010) IESO 18-Month Outlook for June 2010 to November 2011 anticipates growth in normal weather electricity energy consumption of 1.3 per cent and 1.0 per cent in 2010 and 2011 respectively, compared to 0.4 per cent and 0.8 per cent in its November 2009 Outlook cited at page 24 of Ms. McShane's report. The IESO stated in its May 2010 outlook that "The fragile nature of the recovery will mean that growth will be slower leading to modest increases in electricity demand for 2010 and 2011. Some of this is due to the return of production in the automotive and steel industries, which experienced periods of shut downs or low production in 2009. Ultimately, this forecast still faces considerable downside risk due to the debt concerns of a number of nations." Further the Outlook concluded, "Industrial demand will not return to pre-recession levels but will show improvement over the lows of 2009. The high dollar will continue to act as a moderator on Ontario's electrically intensive export-based industries."

Pollution Probe Interrogatory #032

Ref: Ex. C3-T1-S1, page 25

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

Interrogatory

Ms. McShane states here that: "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."

a) Please provide Ms. McShane's views on the percentage of energy that will be supplied by green sources during the test period.
b) Please provide all analyses conducted by Ms. McShane along with all relevant sources used to reach her conclusion that green energy is increasing OPG's dispatch risk.

Response

a) All green sources would include wind, solar, biomass, and hydroelectric, including all of OPG's regulated hydroelectric generation. Limiting the hydroelectric generation to solely that which is under contract to the Ontario Power Authority ("OPA"), as of the end of the first quarter of 2010, the OPA reported in *A Progress Report on Electricity Supply: First Quarter 2010*, that it had 3,785 MW of contracted renewable energy capacity in operation and under development, of which 50 per cent is wind, 31.5 per cent is hydroelectric and the remainder is bioenergy and solar. Of this amount 3,688 MW were expected to be in operation by 2012. On the assumption that total electricity energy demand in 2012 is equal to the IESO May 2010 forecast of 144 TWh for 2011 (*18-Month Outlook From June 2010 to November 2011*), the total percentage of energy produced by these resources could be about 10 per cent of the total during the 2012 test year (assuming that 100 per cent of the resources are operating for the entire year). Wind and bioenergy alone could account for 4 per cent of the total assuming an average 30 per cent capacity factor. The Navigant Consulting *Wholesale Electricity Market Price Forecast for the Period May 1, 2010 through October 31, 2010* presented to the Ontario Energy Board, April 7, 2010 observes that renewable generation under contract with the OPA supplied generation equivalent to 3 per cent of Ontario demand in 2009 and anticipates that renewable generation under contract with the OPA will supply generation equivalent to 9 per cent of Ontario demand in 2011.

b) Ms. McShane has not performed any specific analyses. The conclusion that OPG's dispatch risk is increasing was based on a review of documentation on both the OPA and

IESO website and discussions with OPG. The IESO website states, for example, "It is expected that incidences of surplus baseload generation ("SBG") may increase as Ontario's supply mix continues to change. Current economic conditions have increased the frequency of SBG as overall electricity demand has declined." The changing supply mix to which the IESO refers is a trend toward an increasing proportion of total available resources being baseload generation, which includes wind.

The incidence of SBG is most common when demand is low (e.g., during off-peak, i.e., night time or weekend hours or during shoulder seasons, spring and fall when heating and air conditioning load are lower). The IESO website also indicates that periods of SBG can be exacerbated in the spring when water levels are high due to snow melt, periods when most generators are available, and when there is high production from variable generation such as wind.

OPG's 2009 Annual Report (page 15) discusses the high incidence of SBG conditions in 2009 due to the combination of a weak economy, a cool summer, high output from nuclear and hydroelectric stations, combined with high output from wind. Other factors which exacerbated SBG conditions in 2009 included a reduction in export capabilities and commissioning of gas-fired units.

Wind generation is intermittent; it can only be produced when the wind is blowing. Wind generation is frequently available when demand is relatively low (e.g., off-peak hours and spring), but it is highly variable.

The Feed-in Tariff ("FIT") Program which was developed following passage of the *Green Energy Act* led to initial applications to the OPA for more than 9,000 MW of renewable energy production, of which close to 80 per cent was wind (IESO, *Fit Dispatch and Operability*, March 10, 2010).

OPG's 2009 Annual Report (page 15) states "New wind capacity is expected to have the largest impact on Ontario supply. About half of the wind energy is likely to be produced in off-peak hours and is expected to exacerbate SBG conditions. Whether this increases the amount of water spilled at OPG's generating stations and results in more manoeuvering or shutdown of OPG's nuclear units will depend on the application of curtailment provisions being developed by the IESO to address SBG conditions." The Annual Report also indicates (page 15) that the factors considered by the IESO include safety, regulation, environment, and potential equipment damage.

The introduction of significant variable wind generating capacity into the Ontario generation supply mix, uncertainty with respect to what generation will be curtailed first in instances of SBG, combined with potentially softening demand, increases the dispatch risk (which, as indicated at page 34 of Ex. C3-T1-S1, represents an increased forecasting risk).

Pollution Probe Interrogatory #033

Ref: Ex. C3-T1-S1, page 27, first full paragraph

Issue Number: 3.3
Issue: 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?

Interrogatory

Ms. McShane states here that: 'The Board declined to approve OPG's proposed payment structure, instead adopting a 100% energy-based regulated payment. The Board concluded that OPG should be fully incented to produce as accurate a forecast of nuclear production as possible and should be at risk if actual output falls short of forecast. The adoption of a 100% energy-based regulated payment in lieu of a payment that partially recovers the revenue requirement in a fixed charge results in higher revenue risk to the regulated nuclear operations than anticipated in the 2007 business risk assessment and increases the business risk of OPG's nuclear operations relative to that of the hydroelectric operations."

a) Please provide the details of all deferral accounts that relate to forecasting risk.

b) Please explain the role of such deferral accounts in mitigating forecasting risk.

Response

a) OPG has the following variance and deferral accounts that relate to forecasting risk:

- Nuclear Liability Deferral Account
- Nuclear Development Variance Account
- Hydroelectric Water Conditions Variance Account
- Ancillary Services Variance Account
- Capacity Refurbishment Variance Account
- Nuclear Fuel Expense Variance Account
- Income and Other Taxes Variance Account
- Bruce Lease Net Revenues Variance Account

The specifics of these accounts are described in the OEB's Decision in EB-2007-0905, Chapter 7 and in Exhibit H of OPG's filing in EB-2010-0008. All of these accounts, except the Bruce Lease Net Revenues Variance Account, were proposed by OPG in EB-2007-0905. The Bruce Lease Net Revenues Variance Account was ordered by the OEB as a result of its decision to treat the Bruce lease differently from what had been proposed by OPG. In EB-2007-0905, OPG had also proposed a pension/OPEB variance account, which the OEB declined to approve. OPG has requested one new variance account in this proceeding, an IESO Non-energy Charges Variance Account, described in Ex. H-T3-S1, for an expense which is beyond management's control, is difficult to forecast and has exhibited significant variability.

b) 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.