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File 17939

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VIA COURIER AND *RESS* FILING

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4

Dear Ms. Walli

Re: Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an order or orders determining 2011 and 2012 payment amounts for the output of certain of its generating facilities

Board File No. EB-2010-0008

Please find enclosed herewith the submissions of Power Workers' Union in connection with the above-noted proceedings.

Two paper copies have been sent to the Board via courier, and an electronic searchable pdf version has been filed through the Board's RESS filing system.

Yours very truly,
PALIARE ROLAND ROSENBERG ROTHSTEIN LLP

Original signed by

Richard P. Stephenson
RPS:jr
encl.

cc: J. Kwik (via email)
J. Sprackett (via email)
All Participants (via email)

Doc 774702v1

EB-2010-0008

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 2011 and 2012 payment amounts for the output of certain of its generating facilities.

Submissions of the Power Workers' Union

1. The following are the Power Workers' Union's ("PWU") submissions on the issues reviewed in the matter of Ontario Power Generation Inc.'s ("OPG") 2011-2112 payment amounts for its prescribed assets.

A. GENERAL

I. NUCLEAR

Issue 1.2: Are OPG's economic and business planning assumptions for 2011-2012 an appropriate basis on which to set payment amounts?

Issue 6.4: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's nuclear facilities reasonable?

2. The PWU submits that planning assumptions, as set out in OPG's 2010-2014 Business Plan[1], are an appropriate basis on which to set just and reasonable payment amounts. The PWU considers the inclusion of the following planning assumptions appropriate for the reasons provided in this section below:

a. Pickering B's investment in Continued Operations to 2020;

[1] EB-2010-0008, Exhibit F2, Tab 1, Schedule 1, Attachment 1, Nuclear Operations, 2010-2014 Business Plan, OPG Board of Directors, November 19, 2009, Page 3.

b. Pickering A's derating of 3 per cent concludes in 2009 and the plant's end-of-life is consistent with Pickering B's end-of-life;

c. Darlington begins refurbishment in October 2016; and

d. Project portfolio investments align with end of life assumptions at all three OPG nuclear sites.

3. In addition, the PWU also supports the approach of the 2010-2014 Business Plan to not assume that the generation plan will be affected by market conditions or future stakeholder decisions. The PWU submits that this assumption properly relies on the fact that OPG's nuclear facilities are designed to operate as baseload generation and that extreme market conditions or future stakeholder decisions that may adversely impact OPG's generation cannot be predicted. As a result, there is no reliable basis upon which these developments can be forecast.

4. The PWU submits that OPG's planning process that results in the 2010-2014 Business Plan provides a reasonable framework to balance financial objectives and the needs of business units to plan and execute the work as required to maintain the reliability of OPG's regulated assets.

5. The PWU views the benchmarking initiative that OPG has implemented for nuclear operations as appropriate and consistent with the OEB's direction regarding external benchmarking. On the other hand, the PWU submits that there are limits on the uses to which external benchmarking information can be used in OPG's business planning processes for its nuclear operations. In particular, the PWU submits that there are significant dangers in attempting to integrate external benchmarking information into a "top-down" business planning process such that budgets for required work are artificially constrained on the basis of OPG's performance relative to external comparators.

a. OPG's Top-Down Approach to Business Planning for its Nuclear Operations

6. OPG's 2010-2014 Business Plan process introduced a "top-down" approach for the establishment of OM&A targets. The 2010-2014 Corporate Business Planning

Instructions established business planning guidelines for 2010 requiring an $85M reduction in OM&A compared to previously planned levels for that year. The Nuclear business unit was required to contribute a $40 million reduction.[2] According to the 2010-2014 Corporate Business Planning Instructions, business units were required to indicate how benchmarks/benchmarking have been utilized in assessing performance, and how they have been considered in establishing performance objective and/or cost targets.[3]

7. OPG reported that in 2009, its Nuclear business planning process was augmented with the introduction of a "gap-based" approach that included the use of performance targets and benchmarking results. This change in business planning resulted from a major benchmarking initiative undertaken by OPG Nuclear, with the assistance of ScottMadden Inc. ("ScottMadden"). As described by OPG,[4] the nuclear gap-based business planning process consisted of the following four steps:

- **Benchmarking: Using selected industry performance metrics, establishing the current status of OPG relative to its peers.**
- **Target Setting: Implementing a "top-down" approach to set operational/financial performance targets and generation targets that will drive OPG closer to top quartile industry performance over the five year business plan.**
- **Closing the Gap: By reference to Nuclear's four cornerstone values of Safety, Reliability, Human Performance and Value for Money, developing various initiatives to close the performance gaps between OPG and its industry peers over the five-year business plan.**
- **Resource Planning: Preparing a OPG Nuclear business plan (i.e., the development of cost, staff and investment plans for each site and support group) that is based on the "top-down" targets and incorporates initiatives necessary to achieve targeted results.**

8. OPG's 2010-2014 Business Plan for nuclear operations provided plan over plan cost reductions of $423 million (or $293 million with investment in Pickering B Continued Operations) over the planning horizon.[5]

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[2] EB-2010-0008, Exhibit A2, Tab 2, Schedule 1, Attachment 1, 2010–2014 Corporate Business Planning Instructions, Page 10.
[3] Ibid., Page 9.
[4] EB-2010-0008, Exhibit F2, Tab 1, Schedule 1, Page 4.
[5] EB-2010-0008, Exhibit F2, Tab 1, Schedule 1, Attachment 1, Nuclear Operations, 2010-2014 Business Plan, OPG Board Of Directors, November 19, 2009, Page 2.

9. In setting priorities of Capital and OM&A projects, business units were requested, according to Business Plan instructions (the "Instructions"), to identify all works having cash flows within the Business Plan time horizon. The Instructions stated that "submitted projects must be prioritized to maximize value, while considering risks and OPG's business objectives as well as alignment with business unit strategies and facility Life Cycle Plans (as applicable)".[6]

10. Furthermore, OPG's 2010-2014 Business Plan incorporated an additional "top-down" element. OPG submitted that the capital project portfolio has been held at $172M as a further project cost control effort. Total proposed portfolio amounts, covering OM&A and capital, in the test period are $280.3M for 2011 and $283.2M for 2012. According to OPG, these levels are consistent with OPG's target annual investment levels of $25M to $30M per nuclear unit. OPG said that the target portfolio budget levels, established by OPG in the 2008-2012 Business Planning process, were developed in consideration of: historical investment patterns; project execution capabilities; the potential beneficial impact of the improved project portfolio management processes; and high level comparative data from other nuclear utilities.[7]

11. The PWU is of the view that a proper business plan process must ensure that all work and investments required to maintain asset condition and value are reflected in the Business Plan budget. As such, the PWU submits that a Business Plan must incorporate the budgetary requirements associated with all programs and investments identified in the nuclear engineering reviews, plant condition assessment processes and life cycle plans for the major components.

12. The PWU has grave concerns as to whether a "top-down" budgeting approach is appropriate in the context of a nuclear business like OPG's. A top-down budgeting approach is premised upon a belief that, with sufficient resolve and ingenuity, management will be able to devise and deliver the means to operate the utility's business within a fixed envelope of funds, determined from above. This envelope will be determined by factors independent of the cost forecast of the engineering and

[6] EB-2010-0008, Exhibit A2, Tab 2, Schedule 1, Attachment 1, 2010–2014 Corporate Business Planning Instructions, Page 14.
[7] EB-2010-0008, Exhibit D2, Tab 1, Schedule 1, Page 3.

operations of the business. Essentially, top-down budgeting gives management a budget, with which it must "make do".

13. The PWU submits that this approach is not appropriate for the operation of a nuclear business in the circumstances of OPG, for a number of reasons, including:

a. Nuclear generation is a very capital intensive business. It requires regular and substantial infusions of capital to ensure that it is able to continue to operate on a safe, reliable and efficient basis. These capital requirements have very long lead times and execution times. By their nature, these capital requirements are not subject to arbitrary contraction or expansion in order to comply with top-down driven, year to year, budget variances;

b. CANDU nuclear generation is very technologically complex. The consequences of improper or inadequate operation, maintenance, upgrade or refurbishment are enormous, whether measured in terms of safe operation, reliable operation or efficient operation; and

c. CANDU nuclear generation is subject to strict regulatory requirements imposed by the Canadian Nuclear Safety Commission ("CNSC"). Compliance with these regulatory obligations comes with direct costs, including minimum staffing complements, required testing, required compliance with maintenance schedules (including the elimination of maintenance backlogs), and required security. None of these regulatory controlled costs is susceptible to revision in order to "make do" with a top-down determined budget.[8]

14. The PWU is also concerned with the appropriateness of top-down budgeting in an environment where OPG management is subject to an incentive pay scheme. It is unfair and inappropriate for OPG management to be required to balance the integrity of OPG's multi-billion dollar capital infrastructure with their personal financial well-being, as

[8] Note that one of the means by which OPG is proposing to achieve the "top-down" mandated budget for the test years is the adoption of "Days Based Maintenance". This program is inconsistent with OPG's current CNSC licence conditions, and it will only be achieved if OPG is successful in convincing the CNSC to change those conditions (see Undertaking J3.12).

determined by their compliance or non-compliance with a top-down budget with which they must “make do”.

b. OPG’s Benchmarking

15. The PWU submits that it is particularly inappropriate to employ top-down budgeting where the top-down budget is driven by the results of a flawed external benchmarking exercise. The PWU does not oppose benchmarking. Benchmarking can be a useful management tool which can assist a company in identifying aspects of its business where it is performing below its peers, and in identifying the best performers whose successful practices can be emulated and adopted.

16. In order for benchmarking results of industry peers to be meaningful, two conditions must be met:

a. The comparators must in fact be “peers”, in the sense that they are operating a business which is in fact comparable; and

b. The metric being benchmarked must be subject to some meaningful degree of management control.

It is submitted that the benchmarking exercise performed by ScottMadden does not fulfill either of these requirements.

i. Comparators Must be “Peers”

17. Benchmarking is an intrinsically comparative exercise. In order for the comparison to be meaningful, the two things being compared (i.e. the operations of the subject company and the operations of the peer group) must be “comparable”. The purpose is to determine why two (or more) companies have different costs for undertaking the same activity. No study is required to explain why it costs different companies different amounts to undertake different activities.

18. The problem in this case is that the comparator group chosen by ScottMadden is not in fact “comparable” to OPG. It is comprised of “all North American nuclear generators”. The very significant technological, operational, regulatory and cost differences of CANDU generators relative to other nuclear operators are well documented.

19. No one would suggest that benchmarking the costs of a nuclear plant against a coal plant or a gas plant would be a legitimate or useful exercise.[9] The PWU submits that, from a technology (and cost) perspective, there is no reason to assume that technological diversity between generators using the same resource (i.e. CANDU versus PWR or BWR generators) is any less than technological diversity between generators using different resources (e.g. nuclear versus coal or gas generators).

20. Moreover, by their nature nuclear plants are large operations, each with its own unique challenges and attributes. For proof of the very significant intrinsic differences amongst nuclear plants which make valid comparisons so difficult, it is not necessary to look further than OPG's own fleet of nuclear facilities. The Pickering A, Pickering B and Darlington facilities each have their very own unique cost profiles. It is undeniable that each of OPG's three facilities is more like the other two, than they are like any other North American nuclear facility. Nevertheless, the evidence in this case amply demonstrates why the cost profile of each of the plants is so different than the other, and why there is no reasonable expectation that the costs can or should be brought in line with each other. For example, even OPG agreed that Darlington was not a good benchmark for Pickering.[10]

ii. Benchmark Controllable Costs

21. The purpose of benchmarking is to enable the better management of a business. By necessity, that means its focus must be on cost factors that are within the control of management. It is not clear what value is provided to management through comparative cost data relating to matters over which management has no control. There are no lessons to be learned, and no achievable goals created.

22. Unfortunately, the ScottMadden report does not focus on benchmarking costs which are within the control of management. In fact, a deliberate decision was made to not attempt to isolate those costs. The witness from ScottMadden described this exercise as a "rathole". As a result, neither OPG, nor the Board has the benefit of any

[9] These cost comparisons would be critical at the time a technology choice is being made for a new facility. However, once the facility is constructed, comparison would provide little information useful for the purpose of improving the plant's operating costs.
[10] EB-2010-0008, Transcript Volume 3, Page 221, Line 9 to Page 222, Line 6.

information with respect to the magnitude of the costs differentials with respect to costs that are within OPG's control.[11]

23. The difficulty with ScottMadden's approach is that it is beyond debate that there are significant intrinsic cost differentials between CANDU technology and other nuclear technologies. The economic consequences of these differences are critical for management to understand when the choice of technology is being considered. However, once the technology choice has been made, the differentials become irrelevant. Similarly, there are different regulatory oversight schemes in Canada and the United States, each with its attendant cost implications. These differences may hold academic interest, but have no impact on management's ability to control costs.

24. In summary, there is no doubt that benchmarking can be a valuable management tool. However, there are real limitations with respect to the circumstances where benchmarking provides valid and usable results. Moreover, there are a variety of different purposes to which benchmarking information can be put. To the extent that the results are considered by management as qualitative and directional information, the robustness of the results is of less significance. To be clear, the PWU has no concerns with respect to the ScottMadden benchmarking report being used to fortify OPG's resolve that its nuclear operations should be more cost effective and that substantial efforts to achieve that objective are merited.

25. The difficulty here is that OPG is proposing to use the ScottMadden benchmarking data in a much more prescriptive way. In particular, OPG has adopted ScottMadden's approach, whereby the benchmarking data is used to identify "gaps" in its performance, which are then addressed through a "top-down" budgeting mechanism. Essentially, the performance "gap" is narrowed by reducing the budget that is available to perform the function. This reduction is imposed on a "top-down" basis, without regard to the engineering or operational cost basis of that function. Management is expected to "make do" with that budget.

[11] EB-2010-0008, Transcript Volume 3, Page 222, Lines 6-15.

26. The implicit assumption in this process is that there is a robust basis to justify the elimination of the various “gaps”. It is submitted that, for the reasons described above, no such robust basis exists.

27. Significantly, OPG freely acknowledges that there are significant limitations to which the “gap based” analysis can be put:

> **MR. STEPHENSON: But here is where I am going -- and this is my last point -- if the cost on -- you know, and going back to figure 8 on page 15 -- you know, if -- and we just use the total generating cost metric, the best quartile is $42.60 in -- sorry, this is the... pardon me, I am looking at the wrong page. Sorry, I am on page 7. The best quartile in 2008 was 32.31 is the median. Median, pardon me. And Pickering B, let's use that one, is 58.68. Do you see that?**
>
> **MR. TREMBLAY: Yes.**
>
> **MR. STEPHENSON: Okay. Isn't it important for the Board to know that the difference those two numbers, which is -- whatever it is, $26, right?**
>
> **MR. TREMBLAY: Yes.**
>
> **MR. STEPHENSON: Part of that $26 is under your control, and part of it isn't, in terms of your ability to change that? Fair?**
>
> **MR. TREMBLAY: Yes.**
>
> **MR. STEPHENSON: Okay. It would be wrong for the Board to reach the following conclusion, I am going to suggest to you and I want you to see if you agree with me.**
>
> ***Let's say the Board concluded the following: There is a $26 difference in 2008 between Pickering B and the median. We think that that is too much. It is obvious that that $26 difference is very substantial, and OPG is all to blame, and therefore, their OM&A should be disallowed, to the tune of 30 percent.***
>
> ***Not only would that be the wrong conclusion, that would be the wrong analysis; isn't that true?***
>
> ***MR. TREMBLAY: Well, yes, I would believe it is.***
>
> **I would suggest to you that there is a balancing exercise around the aggressiveness with which we pursue this. We believe we can make these improvements.**
>
> **We believe it is not possible to get to top quartile, and furthermore, you know, Pickering B is still doing lots of improving as a plant.**
>
> **So we believe this plan strikes that balance, and is appropriate. (emphasis added)**[12]

28. The PWU recognizes that it is not the Board’s role to dictate to OPG the form or nature of any benchmarking exercise it may choose to undertake. Nor is it the Board’s role to require OPG to engage in any particular method of business planning. The issue

[12] EB-2010-0008, Transcript Volume 3, Page 223, Line 18 to Page 224, Line 28.

for the Board is whether the proposed work plan that is the product of the benchmarking exercise and business planning process is reasonable and prudent, such that it results in just and reasonable payment amounts.

29. That said, the PWU has grave concerns whether the combination of OPG's flawed benchmarking exercise and its top-down budgeting process will result in a budget and work plan that ensures the safe and reliable operation of is nuclear assets. In particular, the PWU is concerned whether these processes are likely to produce outcomes which are consistent with the Board's statutory objectives of ensuring the "adequacy, reliability and quality" of electricity service.[13]

30. In these circumstances, it is incumbent on the Board to be vigilant in reviewing the proposed work plan to ensure that it is adequate to ensure the safe and reliable operation of OPG's nuclear assets, through the test period and beyond. The evidence is that based on the benchmarking exercise and business planning process OPG has determined reasonable performance targets for the 2010-2014 Business Plan. In the particular circumstances of this case, the PWU submits that, notwithstanding the structural deficiencies of OPG's business planning processes, the proposed work plan set out in the application is reasonable and prudent, albeit minimally so.

c. 2010-2014 Business Plan/Performance and Target

31. Under the Business Plan, the target for safety of the nuclear stations will be to continue to exceed industry safety performance.

32. With regard to reliability, the reasonableness of the targets for the 2010-2014 Business Plan are supported by a comparison of the most recent available reliability data, with the targets set in this proceeding and in EB-2007-0905 summarized in Exhibit 1, in light of the circumstances provided in evidence described below.

[13] Needless to say, because the top-down business planning process is structurally designed to minimize costs, to the extent that this Board is seeking to ensure that OPG's costs are as low as reasonably possible, it can take comfort from results of that business planning process.

Exhibit 1: Comparison of Reliability Performance and Targets (%)

	2009	2010	2011	2012	2013	2014
	Actual (1)	Projected (1)	Target(2)	Target (2)	Target (2)	Target (2)
Unit Capability Factor						
Pickering A	64.2	63.9	82.6	85.3	84.8	86.8
Pickering B	84.0	75.2	81.0	84.7	84.4	81.9
Darlington	85.9	87.4	93.9	94.1	88.7	93.3
Total Generating Cost ($/MWh)						
Pickering A	95.9	102.4	73.0	71.3	74.6	76.1
Pickering B	48.5	61.7	55.6	54.7	56.8	59.7
Darlington	36.0	36.8	35.7	36.7	43.5	40.1

(1): EB-2010-0008, Undertaking J3.3
(2): EB-2010-0008, Exhibit F2, Tab 1, Schedule 1, Attachment 8.

33. With regard to the operational performance targets for Pickering A, the PWU submits that the ability for Pickering A to achieve the target over the 2010-2014 planning period for Pickering A is conditional on the continued improvement of its material plant conditions. Some of the projects that OPG has included to improve the asset conditions of Pickering A during the test years are the Replacement of Standby Boiler[14], Inter Station Transfer Bus Capacity Increase Project[15], Steam Generator Locking Tab Replacement[16] and the Equipment Reliability Restoration Program.[17]

34. The PWU submits that the evidence is that the reliability targets for Pickering B are in the range of what has been expected as a result of the improvement of plant asset condition further to the completion of the 85/5 initiative. The Unit Capability Factor is expected to decrease in 2010 due to the 2010 Pickering Vacuum Building Outage.

35. With regard to Darlington's performance targets, the evidence provided in EB-2007-0905 is that additional investments were made in 2004, 2005 and 2006 to reduce backlog and improve the plant condition.[18] The PWU submits that the resulting

[14] EB-2010-0008, Exhibit D2, Tab 1, Schedule 2, Attachment 1, Project #49267, PDF Pgs 496-511.
[15] Ibid., Project #49270, PDF Pgs 512-532.
[16] EB-2010-0008, Exhibit F2, Tab 3, Schedule 3, Attachment 1, Volume 1, Project #49248, PDF Pgs 20-33.
[17] EB-2010-0008, Exhibit F2, Tab 2, Schedule 1, Pgs 27-28.
[18] EB-2007-0905, Transcript Volume 5, Page 47, Lines 1-11.

improved asset condition speaks to the reasonableness of Darlington's performance targets.

36. In conclusion, the PWU submits that the performance targets are reasonable. With regard to value for money, to the extent that the proposed costs are in line with the performance targets they are indeed just and reasonable. Therefore, the PWU submits that the proposed nuclear work plan provides for just and reasonable payment amounts for the test years and should be approved by the Board.

37. If the Board, despite the above submission, is swayed by other parties to disallow some portion of the proposed nuclear costs, then it is incumbent upon the Board to identify the evidence that has persuaded it to do so and the reasons for its decision to do so, rather than directing a blanket cut. While the applicant must be given the discretion to implement to consequences of any disallowance, it is critical that OPG understand the Board's views as to what it considers to be reasonable and prudent and what are not.

II. BILL IMPACT

Issue 1.3: Is the overall increase in 2011 and 2012 revenue requirement reasonable given the overall bill impact of consumers?

38. The proposed payment amounts and riders represent an increase of 1.7 per cent on the typical residential customer's bill.[19]

a. CME's Evidence

39. The Canadian Manufacturers and Exporters ("CME") filed evidence in this proceeding that sought to demonstrate the extent of bill increases consumers are facing related to factors including the HST, the government's Green Energy Plan, rising commodity prices, etc. The evidence entitled Ontario Electricity Total Bill Impact Analysis August 2010 to July 2015 was prepared by Aegent Energy Advisors Inc. ("Aegent"). Aegent describes its unit cost impact results for non-residential consumers as follows:

> **Based on the forecast total unit cost increase and depending on the reference unit cost, by early 2015, non-residential consumers would see their total unit cost rise**

[19] EB-2010-0008, OPG Argument-in-Chief, Page 5, Lines 9-12.

by 47% - 64% (over the increase already experienced in 2010). This is equivalent to an average, annual, compounded increase of 8.0% -10.4% (again, over the increase already experienced in 2010).[20]

40. And on its unit cost impact results for residential consumers Aegent states:

Based on the forecast total unit cost increase and depending on the reference unit cost, by early 2015, residential consumers would see their total unit cost rise by 38% - 47% (over the significant increase already experienced in 2010). This is equivalent to an average, annual, compounded increase of 6.7 - 8.0% (again, over the significant increase already experienced in 2010).[21]

b. Just and Reasonable Rates

41. In other rate proceedings involving other utilities the Board has considered the impact of factors other than the utility's own costs on bill impact. For example, In EB-2009-0096 the Board noted that:

Fourth, the Board must take into account the overall increase and prospect of further increases in the commodity portion of the bill. While these charges are outside of the control of the applicant, they are no less real for customers. In giving effect to the Board's objective to protect the interests of consumers the Board cannot ignore the overall impacts on customers.[22]

42. The PWU is sympathetic and sensitive to the total bill increases related to the Government of Ontario's policies that consumers have and will continue to experience. The PWU agrees that the Board should be aware of total electricity bill impacts that emanate from all sources. The concern is the manner and extent to which the Board might employ such information in its review of an individual rate application. In the Board's decision in EB-2009-0096 the Board makes reference to its objective of protecting the interests of consumers, but in doing so recognized that the commodity portion of the bill is beyond the control of the applicant in that case.

43. Importantly, the Board's statutory objective is the protection of the interests of consumers, not only with respect to prices, but also with respect to the adequacy, reliability and quality of electricity services. In addition, in its review of OPG's payment

[20] EB-2010-0008, CME evidence, *Ontario Electricity Total Bill Impact Analysis August 2010 to July 2015.* Aegent Energy Advisors Inc., August 2010, Page 7, Paragraph 3.
[21] EB-2010-0008, CME evidence, *Ontario Electricity Total Bill Impact Analysis August 2010 to July 2015,* Aegent Energy Advisors Inc., August 2010, Page 8, Paragraph 2.
[22] EB-2009-0096, 2010-2011 Hydro One Distribution Rate Application, Decision with Reasons, April 9, 2010, Page 13.

amounts application, the OEB's second statutory objective with respect to electricity also comes prominently into play. In particular, the Board is required:

> **To promote the economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.**

44. In determining payment amounts for prescribed generation pursuant to s. 78.1 of the *Ontario Energy Board Act, 1998* the Board is required to approve payment amounts which are "just and reasonable". OPG therefore has every right to recover costs that it is responsible for that the Board finds to be "just and reasonable". As such, in the absence of any evidence that OPG's proposed costs are not just and reasonable, the question is: what authority does the Board have to consider factors beyond OPG's control, and including those over which the Board has no other jurisdiction? How can concern for the rate impact override the Board's objective of allowing the applicant to recover its just and reasonable costs? The PWU submits it cannot.

45. The PWU recognizes that the Board, by virtue of its jurisdiction and mandate, is confronted by a number of competing objectives in discharging its duties. These competing objectives include the promotion and implementation of government policy, the promotion of the reliability and safety of the system, the financial well being of the utilities and consumer rate impacts.

46. What is critical is to remember that this is a cost of service application where the Board is under a statutory obligation to set just and reasonable rates. There is a long line of legal authority that, in such circumstances the Board is under a statutory obligation to permit utilities to recover their prudently incurred costs. Nothing in the Board's statutory objective of protecting the interests of the customers with respect to price derogates from this responsibility.

47. This precise issue was considered by the Board in its recent development of its Cost of Capital policy (the "Report").[23] In the Report, the Board considered the

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[23] EB-2009-0084, *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, December 11, 2009, Page 19, Paragraph 2:

> … Further, the Board notes that the Federal Court of Appeal was clear that the overall ROE must be determined solely on the basis of a company's cost of equity capital and that "the impact of any resulting toll increase is an irrelevant consideration in that determination. This does not mean

application and content of the “fair return standard” for a utility’s invested capital. Of course, the determination of a utility’s return is but one specific example of its overall revenue requirement. In the Report, the Board notes and relies upon the decision of the Federal Court of Appeal in *TransCanada PipeLines Limited v. National Energy Board et al.* [2004] F.C.A 149 which provided that:

> **… even though the cost of capital may be more difficult to estimate than some other costs, it is a real cost that the utility must be able to recover through its revenues. If the… [Board] does not permit the utility to recover its cost of capital, the utility will be unable to raise new capital or engage in refinancing as it will be unable to offer investors the same rate of return as other investments of similar risk. As well, existing shareholders will insist that retained earnings not be reinvested in the utility[24]**

48. In the Report, the Board specifically considers how the obligation to ensure that the utility recovers these costs is to be balanced against the interests of consumers:

> **Second, the Board agrees with the National Energy Board which stated that "[i]t does not mean that in determining the cost of capital that investor and consumer interests are balanced." Further, the Board notes that the Federal Court of Appeal was clear that the overall ROE must be determined solely on the basis of a company’s cost of equity capital and that "the impact of any resulting toll increase is an irrelevant consideration in that determination. This does not mean however, that any resulting increase in tolls cannot be considered by a tribunal in determining the way in which a utility should recover its costs." The Federal Court of Appeal also stated that:**
>
> > **It may be that an increase is so significant that it would lead to “rate shock” if implemented all at once and therefore should be phased in over time. It is quite proper for the Board to take such considerations into account, provided that there is, over a reasonable period of time, no economic loss to the utility in the process. In other words, the phased in tolls would have to compensate the utility for deferring the recovery of its cost of capital.[25]**

49. A utility is entitled to the recovery of its cost of capital because it is one of the prudently incurred costs of providing the utility service. The utility cannot be denied the ability to recover these costs simply by virtue of the impact that those costs may have

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however, that any resulting increase in tolls cannot be considered by a tribunal in determining the way in which a utility should recover its costs.

[24] *TransCanada PipeLines Limited v. National Energy Board, supra, 12*
[25] Cost of Capital Report, *supra*, p. 19

on customers. The existence of an undesirable rate impact does not convert the prudently incurred cost of a fair return into an imprudently incurred cost.

50. Rate impact mitigation may be appropriate through the use of interest bearing deferral accounts, but these mechanisms simply address the *manner* of recovery of costs, not the fact that the costs are recovered. The same analysis applies to all of the utility's other prudently incurred costs.[26] Once the Board has determined that those costs are prudently incurred, it must permit the utility the opportunity to recover those costs, subject to the application of deferral mechanisms that result in "no economic loss to the utility in the process".

51. Importantly, the analysis performed by the Board in the Report was undertaken within the same statutory scheme as governs the Board in this case. There is absolutely no basis for a different balance to be struck between consumers and other interests in this case.

52. It is particularly inappropriate for the Board to undertake the specific exercise which is urged upon it by certain consumers groups in this proceeding. Inconsistent with its legislated objectives and responsibility, the Board is being asked to consider OPG's payment amount impacts on the total electricity bill in light of number of types of costs, over which OPG has no control. These costs fall into two categories. In the first category are costs over which the Board has no jurisdiction, for example, electricity commodity costs, the cost of the "global adjustment" and the impact of HST on electricity bills. To deny the Applicant recovery of otherwise prudently incurred costs by virtue of the impact of these factors would result in the Board attempting to do indirectly, that which it has no statutory authority to do directly – that is, to regulate the cost of the unregulated electricity commodity sources or the HST.

53. In the second category of costs are those costs over which the Board does have regulatory authority – e.g. transmission and distribution costs. It is arguably even more inappropriate for the Board to base any disallowance on the impact of these costs. By definition, these are costs that are being recovered by other regulated utilities based

[26] *Natural Resource Gas Ltd. v. Ontario Energy Board*, 2006 CanLII 24440 (ON C.A.) at para. 28; *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board),* 2006 SCC 4, [2006] 1 S.C.R. 140 at para. 63-65.

upon a prior determination by the Board that those charges are just and reasonable. It is submitted that it is entirely inappropriate and unfair for the Board to deny cost recovery in one case based upon the impact of the recovery of costs approved by it in prior cases.

54. The PWU also understands that certain consumers groups attempt to distinguish the circumstances of OPG, as a government owned entity, from that of other utilities regulated by the Board. It is suggested that, to the extent OPG incurs costs in relation to government policy initiatives (e.g. the *Green Energy Act* ("GEA"), HST), these costs should be borne by the government as shareholder, rather than recovered from customers. This argument is ill-conceived, both legally, and factually.

55. It is simply incorrect to characterize the GEA or the HST as "policy initiatives" of OPG's shareholder. These initiatives are statutory – duly passed into law by the legislature of the Province of Ontario. One of the most basic principles of the Canadian constitutional fabric is the fundamental legal and constitutional separation between the "government" (i.e. the Executive) and the legislature. The statutes in question are the product of the legislature, not OPG's shareholder.

56. It is correct that section 1 of the *Ontario Energy Board Act*, 1998 requires the Board to be mindful of certain policies of the Government of Ontario. Obviously, these policies are distinct from those embedded in legislation enacted by the legislature. Nevertheless, in this situation too, the obligation on the Board is created not by the "government" (i.e. OPG's shareholder), but rather by the legislature, through the provisions of section 1 of the Board's enabling legislation.

57. As noted above, there are options at the disposal of the Board in this proceeding that permit the Board to make a decision as to the manner in which an applicant might recover its costs that address total bill impact without disallowance of prudent costs. The PWU notes two cost elements in this application that are eligible for such consideration.

58. First, OPG has requested an alternative cost recovery mechanism for the Darlington Refurbishment project as the preferred option, from the perspective of both OPG and consumers, through the inclusion of these costs as Construction of Work in

Progress (“CWIP”) in rate base. This mechanism, as noted by the Board in its report on alternative mechanisms for the regulatory treatment of infrastructure investment that could be used to support rate setting. The use of CWIP in rate base treatment has two distinct benefits:

> **“First, it provides a smoothing, or phased-in, effect on rates and thereby mitigates the rate impact that might otherwise take place when large new plant is placed into service. Second, it can reduce borrowing costs.”[27]**

59. Secondly, OPG proposes the extended recovery period for the Tax Loss Variance Account balance (see section c below).

60. The PWU fully acknowledges the Board’s authority to disallow costs that it determines are not reasonable or prudent. That said, it is incumbent on the Board to identify which costs it concludes to fall into that category, to identify the evidence and to provide the analysis that justifies its conclusion. While the PWU appreciates the Board’s desire to avoid short-term rate impacts and its desire not to “micro-manage” the utility, those desires are no substitute for the Board’s fulfillment of its obligation to base its conclusions on evidence and sound reasoning.

c. OPG’s Proposed Mitigation Measures

61. Bill impact concerns have been contemplated by OPG in its 2010-2014 business plan. In its 2010-2014 Corporate Business Plan Instructions, OPG notes:

> **The challenges associated with planning and executing these initiatives would be daunting at any time; the fact that this year’s process is occurring during a period of unprecedented economic turmoil, compounds our task this year. The fact that many Ontario businesses are fighting for survival, and ratepayers are facing economic hardship, means that we can expect unprecedented pressure to aggressively manage our costs, while maintaining safe and prudent operations.**[28]

62. OPG’s top-down business planning process required $85M OM&A savings for 2010. The reduction provided for a level of rate mitigation related to the payment

[27] EB-20009-0152, Report of the Board, The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario, January 15, 2010, Page 15, Paragraph 1.
[28] EB-2010-0008, Exhibit A2, Tab 2, Schedule 1, Attachment 1, 2010-2014 Corporate Business Planning Instructions, Page 9.

amounts of OPG's prescribed assets in the subsequent 2011-2012 test year of costs that are in its control.

63. In a letter that responds to the Minister's May 5, 2010 letter requesting OPG to reassess its planned rate proposal, dated June 24, 2010,[29] OPG's President & Chief Executive Office, Tom Mitchell, describes the rate mitigation initiatives that OPG has undertaken including the extension of the recovery period for costs related to the OEB's decision on OPG's preceding rate application (i.e. Tax Loss Variance Account). The evidence is that this measure reduces the impact of the payment amounts plus riders' sought in the application to 6.2 per cent compared to the 9.6 per cent impact of the original planned application.

64. In cross-examination, counsel for CME referenced OPG's mitigation of the payment amount increases in its preceding application[30] (i.e. EB-2007-0905), which was OPG's first payment amounts application. In response to CME's question as to whether OPG considered mitigation was appropriate in the current application, Mr. Barrett indicated that in the original conception of the application they had not, but that OPG had reconsidered the application in April, 2010 as a result of public concern. The result is the proposal to mitigate the payment amount increases in 2011 and 2012 by extending the recovery period for the Tax Loss Variance Account:

> **MR. DeROSE: Okay. Did you consider whether mitigation was or was not appropriate?**
>
> **MR. BARRETT: In the original conception of the application that we were discussing with stakeholders as part of our stakeholder process, there was no provision for mitigation.**
>
> **But as we discussed, the company's management decided, as a result of public commentary and concern, to go back and see if something further could be done, and what we ended up proposing was a change in the recovery period for the tax loss variance account.**[31]

65. OPG's witness clarified that OPG's proposal to extend the recovery period for the Tax Loss Variance Account as a rate mitigation measure had been decided on prior to

[29] EB-2010-0008, Exhibit L, Tab 4, Schedule 1, Attachment 2.
[30] EB-2010-0008, Transcript, Volume 15, Page 20, Lines 16-28 and Page 21, Line 22 to Page 22, Line 2.
[31] EB-2010-2008, Transcript, Volume 15, Page 21, Line 22 to Page 22, Line 2.

the Minister's letter of May 5, 2010.[32] Therefore, OPG did consider that mitigation was appropriate in the current application and the application filed already includes rate mitigation.

66. However, as OPG's witness also noted, there is a fundamental difference between the prior case and the current case. In the prior case, OPG was transitioning from an "unregulated" mode to a regulated framework. Since the methodology by which the payment amounts were being set was changing, there was the prospect for a very significant change arising by virtue of the implementation of the new methodology under which the payment amounts were being set. It was this fundamental change that prompted the Board's 2006 consultation on Regulatory Options for Setting Payments for the output from OPG's Prescribed Generation Assets (EB-2006-0064). In that decision, the Board observed:

> **The initial payments were determined through negotiations among the Ministry of Finance, Ministry of Energy and OPG, with review by a third party. The rate of return for the prescribed generation assets was determined by the shareholder, the Government of Ontario.**[33]

67. In addition, the Board noted:

> **The existing payments were set without the type of public input or review that a hearing would provide.**[34]

68. This analysis is consistent with OPG's witness' explanation with regard to the rate impact mitigation proposed by OPG in its first application for payment amounts for its regulated facilities in EB-2007-0905:

> **MR. BARRETT: Yes. This was a unique circumstance, I would say, in two respects.**
>
> **One, it was the first application, a transitional application from an interim rate period where rates were established by the government, to a period where we were going to be regulated by the OEB.**
>
> **And perhaps more importantly, it was an application that, absent mitigation, would have featured a rate increase of 19 percent.**[35]

[32] EB-2010-0008, Transcript Volume 15, Page 21, Line 22 to Page 22, Line 24.
[33] EB-2006-0064, Board Decision, Page 10, Footnote 2.
[34] EB-2006-0064, Board Decision, Page 10, Last paragraph.
[35] EB-2010-0008, Transcript Volume 15, Page 21, Lines 3-9.

69. Despite the differences in the circumstances of the current application and the first application that was the mater of EB-2007-0905, OPG, on its own initiative, incorporated an additional rate mitigation proposal in the filed application to those embedded in the original planned application. This in spite of the fact that the rate impact absent the mitigation proposal was, as noted by OPG's witness, below the 10 per cent threshold set out in the OEB's 2006 Electricity Distribution Rate Handbook,[36] a threshold that has come to be viewed as a general guideline of the Board. As such, the PWU submits that the rate mitigation initiative undertaken by OPG in response to public commentary and concern illustrates that OPG did indeed consider and respond to the total bill impact increases raised in CME's evidence.

70. In any event, it is one thing for an applicant to voluntarily forsake some of the revenue requirement it is entitled to as a form of rate impact mitigation. It is an entirely different matter for the Board to disallow reasonable and prudent costs in order to achieve rate mitigation. Whether or not an applicant chooses to do the former, the Board has no legal basis to do the latter.

d. Bill Impact of Production from OPG's Regulated Facilities

71. The prescribed facilities are among the lowest cost generation sources available to Ontario consumers.[37]

72. The evidence is that reduction in OPG's nuclear production that results if Pickering B's life extension is cancelled would need to be replaced with higher priced supply:

> **And you have projected that this -- by virtue of performing this activity and the impacts it has, there is a positive net present value to the electricity system as a whole by doing this work; correct?**
>
> **MR. PASQUET: That is correct.**
>
> **MR. STEPHENSON: And am I right that directionally if, in a perfect world, instead of going out to 2020 you went out to 2021, that NPV would get bigger directionally?**
>
> **MR. PASQUET: That is correct.**
>
> **MR. STEPHENSON: And the reason for that is because the power that is going to have to replace this power is going to be, more likely than not, more expensive.**

[36] OEB, 2006 Electricity Distribution Rate Handbook, Page 131, Paragraph 2.
[37] EB-2010-0008, OPG Argument-in-Chief, Page 1, Lines 14-15.

That's the source of the positive NPV?

MR. PASQUET: That's correct.[38]

73. In addition, with regard to the Pickering B life extension project, OPG states:

> **The economic assessment contained in the attached business case (Attachment 1) shows that the initiative has substantial value to the Ontario electricity system. OPG estimates the net present value ("NPV") of this initiative to be approximately $1.1B (2010 dollars). This NPV is based on the difference between the estimated cost of Pickering B's output and the estimated cost of replacement generation. In seeking to confirm its own NPV estimates, OPG approached the OPA and requested that it provide an analysis of the system benefits associated with the Pickering B Continued Operations initiative. The OPA's assessment is that there could be substantial benefits to the Ontario electricity system from a short term extension to the operating life of the Pickering B units and that they are supportive of OPG proceeding with the Pickering B Continued Operations initiative during the test period, with a reassessment in 2012 when more information becomes available from the work being undertaken.**[39]

74. The substantially lower proposed payment amount level for OPG's regulated hydroelectric assets ($37.38/MWh) compared to the proposed payment amount level for its nuclear assets ($55.34/MWh) speaks to the commonly accepted view that Ontario's hydroelectric generation is its lowest priced source of supply. Therefore, maximizing the value of OPG's regulated assets will help mitigate total electricity bill increases related to higher priced supply that would replace the production from OPG's regulated facilities. Such replacement supply is likely to result in even higher total electricity bill increases than contemplated in the evidence filed by CME.

75. In response to an Interrogatory from CME OPG states:

> **OPG is unaware of any downstream electricity infrastructure investments that would be triggered over the period 2010 to 2014 by its spending plans related to the regulated hydroelectric and nuclear facilities.**[40]

76. OPG's spending plans for its regulated assets would not trigger the need for incremental downstream electricity infrastructure investments because these assets have existing downstream infrastructure in place. Capitalizing on existing assets (e.g. OPG's regulated assets and the associated downstream infrastructure) by

[38] EB-2010-0008, Transcript Volume 4, Page 47, Lines 11-23.
[39] EB-2010-2008, Exhibit F2, Tab 2, Schedule 3, Page 5, Lines 1-12.
[40] EB-2010-2008, Exhibit L, Tab 5, Schedule 6, Page 1, Lines 21-23.

sustaining/improving these assets therefore is the best option to mitigating bill increase impacts.

77. Ensuring ongoing value of OPG's regulated assets will also mitigate total bill increases related to new transmission and distribution required to connect new generation sources and sites required to replace production from OPG's regulated assets.

78. The PWU submits that Board approval of OPG's application therefore will mitigate increases in total electricity bill impact related to several bill components that are not in OPG's control.

79. According to Aegent's study OPG's 2011-2015 cost increase at $273M is a very small part of the expected total dollar increase of $7,739M (about 3 per cent). Should the Board be inclined to disallow any of OPG's costs that it deems to be just and reasonable on the basis of total bill impact of components that are not in the control of OPG, in doing so the Board must be mindful of the fact that the magnitude of the relief that a disallowance would provide consumers will be insignificant relative to the magnitude of the risk that the Board will be exposing the consumers to higher bill increases in the future. Should OPG's cost cuts result in lower future production from the regulated assets, that production will need to be replaced by higher cost supply and related infrastructure requirements.

e. Intergenerational Equity

80. The PWU submits that the Board must also consider the impact of deferring work to mitigate total electricity bill impact for today's rate payers, on future rate payers. There is no evidence that there is any likelihood that electricity cost pressures in Ontario will decline in future years. To the contrary, there is abundant evidence in Ontario's Long-Term Energy Plan: Building Our Clean Energy Future ("Ontario's LTEP"),[41] released on November 23, 2010, that the combination of the costs of refurbishing current infrastructure, the elimination of coal fired generation, and its replacement with higher cost solar, wind and gas generation and associated infrastructure will result in

[41] Exhibit K16.2, Ontario's Long-Term Energy Plan, Building Our Clean Energy Future, November 23, 2010.

ongoing significant electricity cost pressures. As a result, the effect of deferring costs into the future will be to burden future ratepayers with these additional costs. Rather than "smoothing" rate impacts, deferral will unfairly compound future rate impacts.

81. In conclusion, the PWU submits that for consistency with the Board's legislated objectives, any rate mitigation that the Board might consider should not:

a. Result in a shortfall of the revenue required to cover costs for the test year expenditures and programs that the Board finds to be reasonable and just; and

b. Result in the deferral of such expenditures and programs from the test years to future years, nor the cancellation of such expenditures and programs.

82. To the contrary, any rate mitigation method that the Board might consider should:

a. Consider OPG's proposed rate mitigation initiative related to the recovery period of the Tax Loss Variance Account balance and the rate mitigation initiatives embedded in its application; and

b. Minimize bill impact related to the recovery of the test years' costs found to be reasonable and just in a manner that does not aggravate unfair intergenerational subsidy.

83. The PWU agrees with OPG that issues of total bill impact should be considered through the Board's integrated policy framework for the electricity sector and not through individual rate applications.[42] Presumably, that is the intent of the three policy initiatives that the Board is undertaking directed at managing the pace of rate or electricity bill increases.

84. Finally, while it is the PWU's position that total bill impact cannot affect the allowable revenue requirement based on the Board's findings of reasonable and just costs, to the extent that the Board is going to consider evidence on this issue, it must consider all of the evidence, including the Ontario Clean Energy Benefit, the 10 per cent

[42] EB-2010-0008, OPG Argument-in-Chief, Page 5, Lines 15-18.

government rebate that customers will be receiving in the test period,[43] and the government's two hour extension of the off-peak period for time-of-use electricity pricing.[44]

B. RATE BASE

Issue 2.2: Is OPG's proposal to include CWIP in rate base for the Darlington Refurbishment Project appropriate?

a. CWIP in Rate Base Treatment of Darlington Refurbishment is Consistent with Board Policy

85. OPG proposes that capital costs associated with the Darlington Refurbishment project be included in OPG's rate base as the costs are incurred (i.e. "CWIP in rate base" treatment), rather than accumulating those funds until the refurbished Darlington assets are returned to service. OPG submits that the CWIP treatment is consistent with the approach recognized by the Board in its Report in EB-2009-0152: The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario (the "EB-2009-0152 Report").

86. In the EB-2009-0152 Report, the Board examined the need to provide incentives for the construction of certain infrastructure investments, and indicated its willingness to apply certain non-traditional regulatory treatments in order to accomplish this goal. These treatments would augment conventional cost recovery mechanisms.[45] One of the non-traditional mechanisms specifically identified by the Board as being available in appropriate cases was CWIP in rate base.[46]

87. OPG has suggested that the costs associated with the Darlington Refurbishment project are appropriate for CWIP in rate base treatment on the basis that:

a. The project costs are significant;

[43] Ontario Government, News Release: *McGuinty Government Introduces New Measures to Help Ontario Families and Reduce Debt*, November 18, 2010.
[44] Exhibit K16.2, Ontario's Long-Term Energy Plan, Building Our Clean Energy Future, November 23, 2010.
[45] EB-2009-0152, Report of the Board, *The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario*, Page 10.
[46] Ibid., Page 14.

b. The project lead times are significant – expenditures will be incurred over many years before the refurbished units are scheduled to come into service;

c. There are a variety of risks of project delays;

d. In the absence of CWIP in rate base treatment, the costs associated with the Darlington Refurbishment will result in a deterioration of OPG's credit metrics and a risk of increasing its borrowing costs; and

e. In the absence of CWIP in rate base treatment, there will be considerable rate shock in the early years after the refurbished units come into service due to the rapid increase in OPG's rate base at that time.[47]

88. As noted in the PWU's argument on Issue 1.3 above, the last two factors were specifically identified by the Board in the EB-2009-0152 Report.

> **Including CWIP in rate base provides two principal benefits. First, it provides a smoothing, or phased-in, effect on rates and thereby mitigates the rate impact that might otherwise take place when the large new plant is placed into service. Second, it can reduce borrowing costs. Permitting a utility to recover CWIP funding can also reduce a projects total net present value cost, although it can raise intergenerational equity issues.**[48]

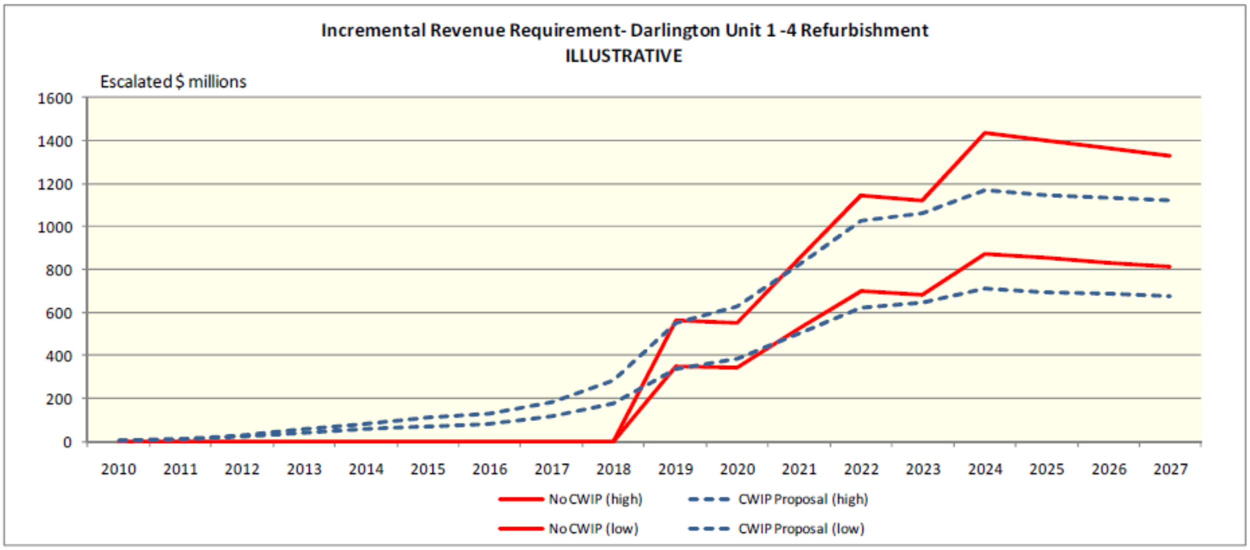
89. OPG provided evidence with respect to how each of these two factors would apply to it, in respect of a major project like the Darlington Refurbishment. With respect to the issue of the impact on its credit metrics, OPG referred to a report by debt rating agency DBRS, which commented that:

> **Interest expense is expected to increase in the medium term, given the debt financing required to fund the increased capital expenditures; therefore, coverage ratios will weaken slightly. Furthermore, should the nuclear refurbishments and nuclear new-build generating projects be approved, the Company will witness a substantial increase in interest expense as the projects are significant in size.**
>
> **…**
>
> **As debt is added to fund capital expenditures, credit metrics would be expected to decline from current levels as assets do not generate earnings or cash flows until placed in service. Once in service, metrics would be expected to improve.**[49]

[47] EB-2010-0008, Exhibit D2, Tab 2, Schedule 2, Page 6, Line 11 to Page 7, Line 6.
[48] EB-2009-0152 Report of the Board, Page 15.
[49] EB-2010-0008, Exhibit A2, Tab 3, Schedule 1, Attachment 1, Pgs. 7-8.

90. With respect to the "rate smoothing" issue, OPG provided a chart of the projected cash flows associated with the Darlington Refurbishment project reflecting the effect of the conventional regulatory treatment as well as a CWIP in rate base approach:

Graph 2
All 4 Darlington Units



91. From Graph 2, provided in its pre-filed evidence,[50] OPG reported that in the absence of CWIP in rate base treatment, customers are forecast to experience a very significant rate impact in 2019, 2021, 2022 and 2024, leading to an overall 5.8 per cent – 9.5 per cent rate increase for the period from 2019 to 2024. If CWIP in rate base treatment is used, this impact is smoothed over several years (2010-2024), with a maximum annual increase of 1.0 per cent – 1.6 per cent occurring in 2019.[51]

92. OPG's CWIP in rate base proposal was criticized by a number of intervenors, on a number of different bases. The PWU submits that, as demonstrated below, none of these criticisms are valid.

[50] EB-2010-0008, Exhibit D2, Tab 2, Schedule 2, Page 7.
[51] EB-2010-0008, Exhibit D2, Tab 2, Schedule 2, Page 7, Lines 1-6.

i. EB-2009-0152 Report is Restricted to Transmitters and Distributors

93. It was suggested that CWIP in rate base treatment is not available to OPG, because the EB-2009-0152 Report is applicable only to transmitters and distributors.[52] It is correct that the focus of the EB-2009-0152 Report is on the transmission and distribution sectors. However, it is very clear that the Board expressly contemplated that the treatments described in the EB-2009-0152 Report could apply to other rate regulated utilities:

> **Typically, Green Energy Act-related investments relate to investments by electricity distributors and transmitters to accommodate the connection of renewable generation or to develop and implement a smart grid… However, the Board will consider applications for one or more alternative mechanisms for any Green Energy Act-related investment provided that the investment is undertaken by an entity as part of its rate regulated activity. References in this Report to "utilities" should be construed accordingly. The alternative mechanism may be available to other types of projects in appropriate circumstances.**[53]

94. This passage of the EB-2009-0152 Report makes it abundantly clear that when it referred to "utilities" it was not limiting that term to distribution and transmission facilities. OPG is one of the few entities which is rate regulated by the OEB which is not a distributor or transmitter. It is clear that the Board intended the EB-2009-0152 Report to have a more general application, and it is difficult to see how that application could not encompass OPG.[54]

95. The intent of the Board in this regard is even clearer when the process by which the EB-2009-0152 Report was developed is considered. In particular, there was a consultation process prior to the finalization of the report. In that process, counsel for the Green Energy Coalition ("GEC") specifically urged the Board to ensure that any non-traditional regulatory treatment not be made available to OPG or its nuclear program by, "explicitly limit[ing] the application of any such mechanisms to the transmission and

[52] At one level, the entire debate as to whether or not the Board contemplated that the Report be applicable to the circumstances like the present case is really irrelevant. The Report simply reflects a policy of the Board. It is not binding on any panel of the Board in any particular case. The real question for this panel is whether it agrees that the concerns and the approach recognized by the Board in the Report can be usefully applied in the present case. For the reasons expressed herein, it is the PWU's view that the Report can be usefully applied here.
[53] EB-2009-0152, Report of the Board, pp. 13-14.
[54] The wording in the EB-2009-0152 Report is sufficiently broad that it would appear to encompass not only rate regulated electricity entities, but also rate regulated natural gas entities.

distribution sector".[55] Contrary to this submission, the report contains no such "explicit limit" on its application. Rather, as noted above, the EB-2009-0152 Report explicitly provides an expansive definition of "utilities".

ii. The EB-2009-0152 Report does not apply to Nuclear Projects

96. It was also suggested that the EB-2009-0152 Report does not apply to nuclear projects, and that it was limited to GEA related projects. Again, it is apparent that GEA related projects were the primary focus of the EB-2009-0152 Report. However, as noted above, the EB-2009-0152 Report expressly provides that, "The alternative mechanism *may also be available to other types of projects in appropriate circumstances*." (emphasis added).[56] It is beyond argument that in referring to "other types of projects", the Board was referring to non-GEA-related projects.

97. It is clear that the issue for the Board was not in a narrow characterization of the identity of the proponent or type of the project, but rather whether the nature of the infrastructure investment fell within the concerns identified by the Board arising from the application of the traditional regulatory treatment. Viewed from this perspective, it is clear that the Darlington Refurbishment project is the type of project that would benefit from the application of the mechanisms described in the EB-2009-0152 Report.

iii. The Need for the Project

98. In Exhibits D2-T2-S1 and D2-T2-S2 OPG deals with each of the seven criteria listed by the Board in the EB-2009-0905 Report. With respect to the Need of the Project criterion, the PWU submits that the Darlington Refurbishment is a key component of Ontario's LTEP. With respect to the power supply needs of the province, Ontario's LTEP provides that:

> **Through initiatives already underway, the province will be able to reliably meet electricity demand through 2015. Ontario needs to plan now for improving the power supply capacity to meet the province's electricity needs beyond 2015.Ontario must plan in advance because:**
>
> > **• Insufficient investment between 1995 and 2003 left an aging supply network and little new generation**

[55] EB-2010-0008, Exhibit K.14.1.
[56] EB-2009-0152 Report of the Board, Pgs 13-14.

> **• Additional clean generation will be needed to ensure a coal-free supply mix after 2014**
>
> **• Nuclear generators will need to go offline while they are being modernized**
>
> **• The population is projected to grow.**

> **To meet these needs Ontario will need a diverse supply mix. Each type of generation has a role in meeting overall system needs. Ontario requires the right combination of assets to ensure a balanced supply mix that is reliable, modern, clean and cost-effective. Ontario will also, first and foremost, make the best use of its existing assets to upgrade, expand or convert facilities.**[57]

99. A key feature of the Ontario's LTEP related to nuclear power supply is as follows:

> **The government is committed to clean, reliable nuclear power remaining at approximately 50 per cent of the province's electricity supply. To do so, units at the Darlington and Bruce sites will need to be modernized and the province will need two new nuclear units at Darlington. Investing in refurbishment and extending the life of the Pickering B station until 2020 will provide good value for Ontarians.**[58]

100. It is clear that in order to meet the needs of the Province of Ontario with respect to a diverse supply mix, requiring a combination of assets to ensure a balanced supply mix that is reliable, modern and cost-effective, OPG will necessarily be required to proceed with the Darlington Refurbishment project.

iv. Application of CWIP in Rate Base Treatment is not Required for the Project to Proceed

101. It was suggested that CWIP in rate base treatment in this case is not required because OPG has acknowledged that the project will proceed even if CWIP in rate base treatment is denied.[59] The Board expressly addresses this issue in the EB-2009-0152 Report itself. It concludes that it will not be necessary for a utility to establish that "but for" CWIP treatment, the project will not proceed:

> **The Board will not impose a "but for" requirement in assessing the requisite relationship between the alternative mechanisms requested and the risks and challenges associated with the project. In other words, it will not be necessary**

[57] Exhibit K16.2, Ontario's Long-Term Energy Plan: Building Our Clean Energy Future, November 23, 2010, Page 9.
[58] Exhibit K16.2, Ontario's Long-Tern Energy Plan: Building Our Clean Energy Future, November 23, 2010, Page 10.
[59] EB-2010-0008, Green Energy Coalition, Evidence Prepared by Paul Chernick, August 31, 2010, Page 12, Lines 1-10.

for the applicant to demonstrate that the project will not, or is likely not, to proceed unless an alternative mechanism is granted in support of the project.[60]

v. Application of CWIP in Rate Base Treatment Violates the "Used and Useful" Principle

102. It is acknowledged that the application of CWIP in rate base treatment in this case is not consistent with the principle that ratepayers should not bear the costs of utility investments unless and until the associated assets are "used and useful". However, that result is not a feature unique to OPG or the Darlington Refurbishment. Rather, it is an intrinsic feature of the CWIP in rate base mechanism. It is clear that when the Board developed the EB-2009-0152 Report it was prepared to approve exceptions to the traditional "used and useful" approach. This submission is an argument that the Board should never have adopted the EB-2009-0152 Report, and not an argument that the mechanisms contemplated by the EB-2009-0152 Report should not be applied here.

vi. Application of CWIP in Rate Base Treatment Creates "Intergenerational Inequity"

103. It was suggested that CWIP in rate base treatment should not be approved in this case because it would result in OPG's customers "loaning" funds to OPG to finance assets when those customers are not receiving the benefit of those assets. Put another way, it is suggested that current customers are subsidizing future customers in the sense that current customers are paying too much and future customers are paying too little in respect of the cost of these assets.

104. Again, this issue is not unique to OPG's application in this case. Rather, it is intrinsic in the use of CWIP in rate base treatment. Again, this submission is an argument that the Board should never have adopted the EB-2009-0152 Report, and not an argument that the mechanisms contemplated by the EB-2009-0152 Report should not be applied here.

105. The PWU is not indifferent to unreasonable intergenerational inequity. However, while the CWIP in rate base treatment of the Darlington Refurbishment smoothes rate impact, Table 2 and 3 below from Exhibit K13.4 illustrates that the resulting

[60] EB-2009-0152 Report of the Board, Page 20.

intergenerational re-allocation of the Darlington Refurbishment costs is not significant and is reasonable.

Table 2
Cost Recovery from Ratepayers
$6 B Project Cost Examples

	Under OPG' s CWIP Proposal		Current Regulatory Treatment	
	In $ Millions		in $ Millions	
2011-2024	3,600	21%	2,860	16%
2025-2039	9,060	54%	9,990	57%
2040-2053	4,240	25%	4,600	26%
2011-2053	16,900		17,450	

Source: Undertaking K13.4

Table 3
Cost Recovery from Ratepayers
$10 B Project Cost Example

	Under OPG' s CWIP Proposal		Current Regulatory Treatment	
	in $ Millions		in $ Millions	
2011-2024	5,860	21%	4,660	16%
2025-2039	15,180	54%	16,560	57%
2040-2053	7,100	25%	7,690	27%
2011-2053	28,140		28,910	

Source: Undertaking K13.4

vii. Application of CWIP in Rate Base Treatment is Inappropriate because Customers' Cost of Capital is Higher than OPG's

106. It was suggested that the application of CWIP in rate base treatment is inappropriate in this case because OPG's customers have a higher cost of capital than OPG does. In effect, it was suggested that the effect of CWIP in rate base is to increase overall costs to customers, because the projects in question would be financed by customers, whose cost of borrowing is higher than OPG's.

107. There was no evidence with respect to cost of capital of customers of OPG. There is no doubt that for some customers the cost of capital is higher than that of OPG.

For others it is likely lower.[61] Regardless, this is another example of a generic issue regarding the use of the CWIP in rate base methodology. There is nothing unique about OPG, or its customers or their respective costs of capital, than would be the case with many, if not most, other utilities. As a result, this submission is an argument that the Board should never have adopted the EB-2009-0152 Report, and not an argument that the mechanisms contemplated by the EB-2009-0152 Report should not be applied here.

viii. Period of Rising Rates/Bill Amounts

108. There is no merit to the suggestion that CWIP in rate base should not be approved because we are in an environment of rising rates. The OEB Chair's June 1, 2009 statement[62] specifies the consideration of more innovative approaches to cost recovery primarily in relation to infrastructure investments relating to the accommodation of renewable generation and the development of the smart grid but potentially also applicable to other types of projects in similar circumstances. The EB-2009-0152 Report therefore was designed most directly to deal with GEA related projects, which the Board well understood to have the effect of increasing rates and bill amounts.

109. The OEB Chair's April 3, 2009 statement[63] made the commitment to "create conditions that will foster timely and appropriate investment in electricity distribution and transmission *while ensuring that the interests of the ratepayers continue to be protected*." (emphasis added) That commitment makes it clear that CWIP in rate base treatment for projects that meet the Board's criteria would in the Board's view ensure that the interest of ratepayers continue to be protected. The evidence is that the Darlington Refurbishment project meets the Board's criteria for CWIP in rate base treatment.[64]

[61] EB-2010-0008, Transcript Volume 13, Page 67, Lines 21-27.
[62] June 1, 2009, Statement from the Chair, Initiatives to Implement an Integrated Regulatory Framework for Electricity Infrastructure Investment.
[63] April 3, 2009, Statement from the Chair, Initiatives to Implement an Integrated Regulatory Framework for Electricity Infrastructure Investment.
[64] EB-2010-0008, OPG Argument-in-Chief, Pgs 74-78.

b. GEC Expert Evidence

110. The GEC filed evidence that included comment on the inclusion of CWIP in rate base for the Darlington Refurbishment project prepared by Mr. Paul Chernick. Mr. Chernick's analysis on the appropriateness of CWIP in rate base treatment for the Darlington Refurbishment project depends on the interpretation and application of a prior Board decision (EB-2006-0501) on a Hydro One application for CWIP in rate base treatment. That decision was made prior to the Board's issuance of its EB-2009-0152 Report in which the Board adopts the CWIP in rate base approach as an alternative regulatory mechanism and the regulatory context for that decision therefore differs from the current context. Further, the EB-2009-0152 Report specifies that it will consider the application of this mechanism on a case-by-case basis to balance unique investment challenges and protect the interests of ratepayers.[65] There is no doubt that the Darlington Refurbishment presents a unique investment challenge.

111. The concerns that Mr. Chernick identifies (e.g. the criterion of used and useful, intergenerational inequity) are generic issues, about which the Board has significant expertise and does not require the assistance of expert evidence. More significantly, the criticisms of the proposal are merely complaints about the CWIP *concept* rather than OPG's specific proposal. In other words, Mr. Chernick is attempting to reargue the Board's decision that led to the Board's acceptance of the CWIP in rate base approach as a regulatory mechanism, rather than the merits of this case.

112. In conclusion, it is submitted that none of the criticisms of OPG's CWIP proposal are valid. In fact, none actually focus on the genuine issue: whether the nature of the project for which CWIP in rate base is proposed meets the criteria laid out by the Board in the EB-2009-0152 Report. In Exhibits D2-T2-S1 and D2-T2-S2 OPG deals with each of the seven criteria listed by the Board in the EB-2009-0152 Report. It is submitted that the evidence was not seriously challenged, and that the evidence establishes that the issues associated with the Darlington Refurbishment are entirely consistent with the infrastructure projects discussed in the EB-2009-0152 Report. On that basis, OPG's proposal should be approved.

[65] EB-2009-0152 Report of the Board, Page 19.

113. The Board can address concerns related to differences between the forecast costs and the actual costs through the capacity refurbishment variance account as proposed by OPG.[66]

C. CAPITAL STRUCTURE AND COST OF CAPITAL

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

114. In EB-2007-0905, the Board found that the evidence was not sufficiently robust to set separate cost of capital parameters for OPG's regulated hydroelectric and nuclear prescribed assets. In that proceeding, the Board saw the merits for further investigation on this issue, which would be explored in OPG's next application.

115. The PWU agrees with OPG's Argument-in-Chief that Ms. McShane was the only expert that provided the "incremental" analysis that the Board was seeking in this proceeding. OPG submitted that none of the five quantitative methodologies assessed by Ms. McShane were sufficiently robust as a basis for estimating technology-specific cost of capital structures for OPG's regulated hydroelectric and nuclear prescribed assets. The non-quantitative analysis performed by Ms. McShane, did not provide sufficiently robust information to serve as the basis for estimating technology-specific cost of capital.[67]

116. In their prefilled evidence, Pollution Probe's expert witnesses Drs. Kryzanowski and Roberts, on behalf of Pollution Probe, recommended a 40 per cent equity ratio for OPG's regulated hydroelectric and 50 per cent for OPG's nuclear. They submitted that by applying weights, based on installed capacity of 66.47 per cent for nuclear and 33.53 per cent for hydroelectric, the recommended capital structures of 40 per cent for hydroelectric and 50 per cent for nuclear resulted in an overall rounder recommended equity ratio for OPG of 47 per cent which is consistent with the equity ratio of 47 per cent, as mandated by the Board in EB-2007-0905.

[66] EB-2010-0008, Transcript Volume 13, Page 76, Lines 15-26.
[67] EB-2010-0008, OPG Argument-in-Chief, Page 68-69.

117. When asked in an interrogatory to apply rate-base weights to Drs. Kryzanowski's and Roberts' recommendation of 40 per cent equity ratio for hydroelectric and 50 per cent for nuclear, Pollution Probe arrived at an overall weighted equity ratio of approximately 44 per cent for 2011 and 2012. The 3 per cent shortfall was subsequently allocated to both hydroelectric and nuclear such that the resulting equity ratios were, respectively adjusted, to 43 per cent and 53 per cent to arrive at the fixed equity ratio of 47 per cent for both test years.[68]

118. The record of the proceeding is clear that the evidence submitted by Pollution Probe's expert witnesses Drs. Kryzanowski and Roberts does not provide any incremental analysis with respect of what they filed in EB-2007-0905.

> **DR. ROBERTS: It is, because I think the answer to the question is there, where it says "Overview of this section" and the first sentence -- first two sentences, I think, address your question, where we say:**
>
> **"This section updates and extends our discussion of capital structure for each type of OPG's regulated assets, originally presented in our evidence in EB-2007-0905. Following this same outline, we begin with a brief overview."**
>
> **So I think what we're trying to say here is we took the same approach. We updated it, and we extended it by adding some additional analysis.**
>
> **MR. SMITH: Well --**
>
> **DR. KRYZANOWSKI: I guess I could even extend in terms of that. It is the same approach we used for OPG, and it is the same approach we use for other utilities. So if you can use it for other utilities, there is no reason you can't use it for a division of a utility.**
>
> **MR. SMITH: I am not surprised to hear you say that, and I am sure you are referring to your testimony in Alberta, and we will come to that. But the bottom line is that the framework that you employ in ultimately reaching your conclusion, which is the nine-part scoring method, is the same as the framework you used the last time; correct?**
>
> **DR. ROBERTS: Yes. It says so right here. What is new is that we updated it and extended it by adding some additional metrics within that framework.**
>
> **MR. SMITH: Okay. So we are going to go over that, but, as I understand it, your framework -- well, let me just drill down on your conclusions.**
>
> **The conclusions the last time around were 40 percent hydro, 50 percent nuclear; correct?**
>
> **DR. ROBERTS: Correct.**
>
> **MR. SMITH: And your conclusions in your prefiled evidence were 40 percent hydro, 50 percent nuclear?**
>
> **DR. ROBERTS: Correct.**

[68] EB-2010-0008, Exhibit M, Tab 10.15, Schedule 19.

MR. SMITH: And the only reason we are at 43 and 53 is a result of an interrogatory where it was pointed out that allocating by production weighting would leave OPG some dollars short and result in an overall equity thickness of 44 percent as opposed to 47 percent; correct?

DR. ROBERTS: That's correct. We're not here to try to prove our -- massage our ego, but to try to come up with evidence that would be most helpful. When we saw that, we realized it was a better way to doing it and that's why we made the change.

MR. SMITH: But there was no additional analysis, in terms of assessment of risk, business risk, or change in your framework, that prompted the change from 40 to 43, was there? It was the recognition that if you stuck to the same numbers, OPG would be short; correct? That's right, isn't it?

DR. KRYZANOWSKI: That's correct. The 47 percent is given. We may feel that the global percentage might be different, but the 47 percent is a given.[69]

119. The PWU agrees with OPG that Drs. Kryzanowski and Roberts did not provide further analysis to that provided in EB-2007-0905. Drs. Kryzanowski and Roberts used the same methodology as employed in the prior proceeding for rating OPG's business risks for its regulated hydroelectric and nuclear prescribed assets relative to the electricity sectors and other Canadian utilities. Drs. Kryzanowski and Roberts also used the same equity ratio sample benchmarks. They only updated the benchmarks and OPG's nuclear risk rating reflecting the Board's decision not to allow fixed payments. Not surprisingly, the recommendation provided by Drs. Kryzanowski and Roberts of 40 per cent for regulated hydroelectric and 50 per cent for nuclear in this proceeding does not differ from their recommendations in EB-2007-0905.

MR. SMITH: Now, the last time, as I understand it, you reached a conclusion that the hydro weighting applying your matrix was 1.8; is that correct?

DR. ROBERTS: I believe it is, yes.

MR. SMITH: And that continues to be your view?

DR. ROBERTS: In terms of the risk rating, yes, I believe that's right.

MR. SMITH: And then for nuclear the last go-round, it was I believe 2.3, and now it is 2.6. But your overall ratings have really moved from just 2.1 to 2.3. Have I understood that correctly?

DR. ROBERTS: The last thing that you said in terms of nuclear is correct, that we did make an adjustment there based on the decision that the Board made in terms of not allowing fixed payments. That's correct.

MR. SMITH: I take it you agree with the general proposition that transmission carries the lowest risk?

DR. ROBERTS: We do.[70]

[69] EB-2010-0008, Transcript Volume 12, Page 163, Line 10 to Page 165, Line 8.

120. The evidence submitted by Drs. Kryzanowski and Roberts is in essence the same as that provided in the prior proceeding. As a result, it should not be considered by the Board as “further investigation”.

121. The PWU concludes that, there are no grounds to support a Board finding that the evidence is sufficiently robust, this time, to set separate cost of capital parameters (i.e. capital structure ratios) for OPG’s regulated hydroelectric and nuclear prescribed assets. Therefore the Board should approve OPG’s proposal to continue the use of a single cost of capital for its prescribed facilities.

D. CAPITAL PROJECTS

I. REGULATED HYDROELECTRIC

Issue 4.2: Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

Issue 6.1: Is the test period Operations, Maintenance and Administrative budget for the regulated hydroelectric facilities appropriate?

122. With regard to OPG’s proposed regulated hydroelectric capital investments and OM&A expenditure, the PWU submits that the proposed costs and programs are reasonable and prudent and should be approved by the Board. OPG’s hydroelectric assets are long-lived assets; it is OPG’s expectation that they will continue in service for many years into the future. However, they are also aging assets, and they require ongoing investment in order to maintain their value and adequate levels of service reliability.

123. Any deferral of hydroelectric work programs or investments included in OPG’s 2010-2014 Business Plan resulting from asset condition assessments and investment management of the hydroelectric assets will see a decrease in net value of the project portfolio. There is no serious suggestion that the proposed work does not need to be performed, or that it can be performed at less cost than has been budgeted. Any

[70] EB-2010-0008, Transcript Volume 12, Page 165, Lines 9-26.

reduction in the proposed budgets will simply cause the deferral of needed work from the test period to a later time.

124. The issues that set the context for the PWU's submission are as follows:

a. Aging hydroelectric assets;

b. Historic period of low hydroelectric re-investment levels;

c. Assets depreciating faster than capital additions;

d. OPG's Corporate 2010-2014 Business Plan Instructions;

e. Hydroelectric Business planning process to maintain/enhance value; and

f. Absence of any serious challenge to, or evidence that any of the proposed projects or their costs are not reasonable or prudent.

a. Aging Hydroelectric Assets

125. The evidence indicates that OPG's hydroelectric facilities, including the regulated assets, are aging.[71] In a presentation (the "Presentation") to OPG's Board of Directors on the Hydro Generation Business Plan 2010-2014[72] OPG's Executive Vice-President, Hydro Generation states: "There is risk of deteriorating performance and safety without significant continued re-investment". In addition, the Presentation states that the "Business Plan addresses the need to sustain and improve the existing assets for long term per the Hydro mandate".[73]

126. By their nature, hydroelectric assets are long-lived assets. An Ontario without the hydroelectric prescribed generating stations is unimaginable for the foreseeable future.[74] OPG has not considered at any scenario where the hydroelectric prescribed assets are not going to be either run or replaced.[75] OPG's witness indicated that under this circumstance, the sustainment of the hydroelectric assets is a key priority and

[71] EB-2010-0008, Transcript Volume 2, Page 7, Lines 10-14.
[72] EB-2010-0008. Exhibit F1, Tab 1, Schedule 1, Attachment 1.
[73] Ibid., Page 4 of 36.
[74] EB-2010-0008. Transcript Volume 2, Page 2, Lines 11-28; Page 3, Lines 1-9.
[75] EB-2010-0008, Transcript Volume 2, Page 3.

sustaining and prolonging the life of these assets are a core priority for OPG's hydroelectric business.[76]

127. The aging of the hydroelectric assets is one of the justifications for the funding OPG is seeking for its prescribed hydroelectric assets.

> **MR. STEPHENSON: But you're telling the Board that one of the justifications for the work program that you're seeking to fund is your aging assets; correct?**
>
> **MR. MAZZA: Yeah, it is. It is one of the elements.**

128. Given the age demographics of the hydroelectric assets, the PWU is of the view that it is important for the Board in considering the reasonableness and prudence of OPG's proposed hydroelectric budget, to understand whether OPG's work plan improves the age portfolio of its prescribed hydroelectric assets, or at minimum, maintains the status quo.

129. The PWU sought an undertaking during the hearing asking OPG whether at the end of the five-year plan, the age of the hydroelectric generation station components as they pertain to the regulated assets are going to be newer, older, or the same. OPG did not provide an answer to that inquiry. Rather, OPG's response was that with its continuing maintenance and investment programs, it is OPG's opinion "that the regulated hydroelectric stations will be in about the same condition at the end of five years".[77] Given that OPG is expressly relying upon asset age as a key driver of the need for ongoing investment in its hydroelectric assets, it is submitted that it is important for the Board to understand what the effect of the proposed work plan is on the demographics of OPG's regulated hydroelectric assets. The PWU submits that OPG should be directed to file this information in any future payment amounts application.

130. The PWU submits that while the Business Plan is intended to address the need to sustain and improve existing assets for the long term, on the evidence available to the Board, the proposed work plan will only minimally meet this objective. There is therefore no margin in the proposed hydroelectric budget that will ensure that the

[76] Ibid.
[77] EB-2010-0008, Undertaking J2.1.

condition of the assets would even be sustained in the long term, let alone improved, should there be regulatory disallowance of the proposed costs.

b. Hydroelectric Investment Cycle

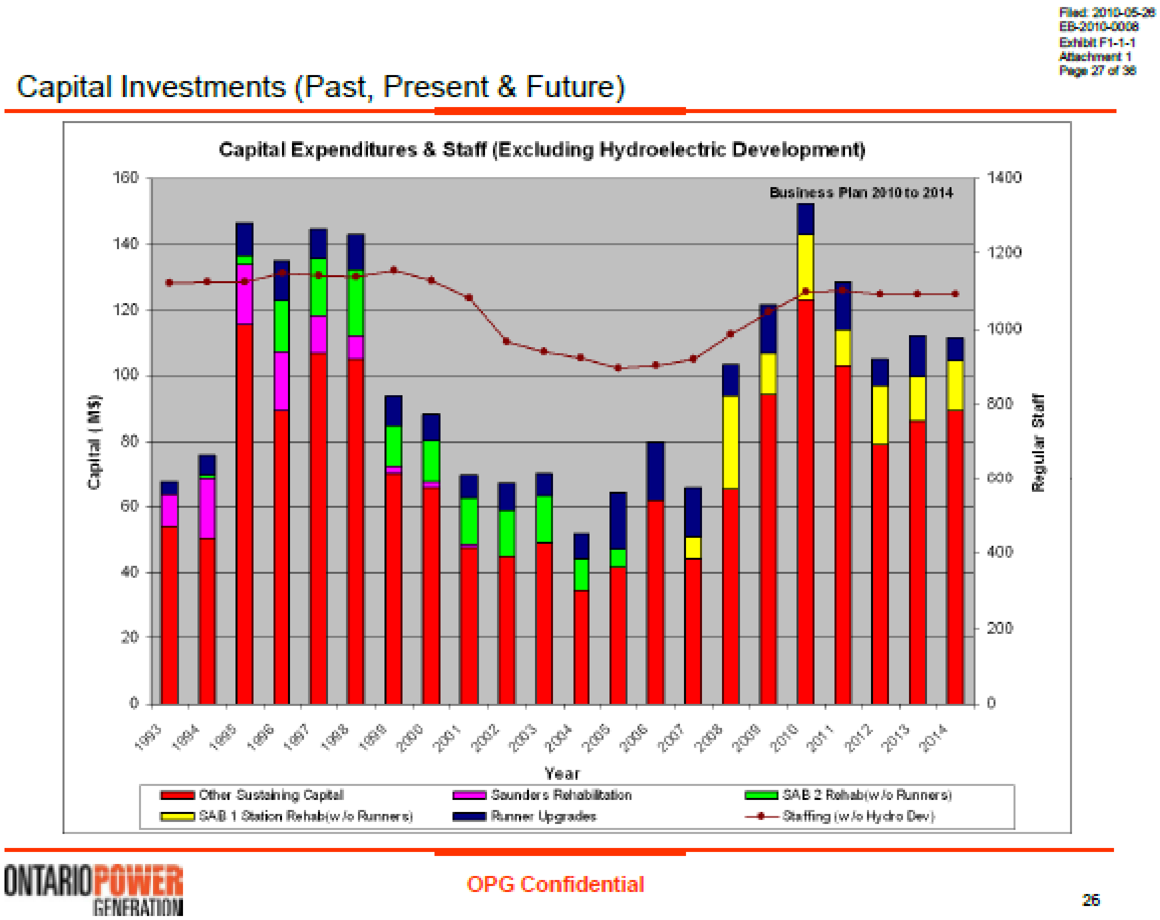
131. With regard to re-investment levels, Slide 3 of the Presentation states that OPG "has invested approximately 0.5% to 1.5% per year of "replacement cost" in the past 10 years (excludes new facilities)". Given that the presentation is dated November 19, 2009, it would appear that the "10-year period" refers to the period of 1999-2008. With regard to OPG's range of annual hydroelectric replacement cost, Slide 3 notes that industry experts consider 1% to 3% per year of "replacement cost" to be reasonable. The PWU submits that according to the evidence, the hydroelectric annual replacement costs in 1999-2008 are at or below or at the low range of the re-investment levels considered to be reasonable by industry experts.

132. At the hearing OPG's witness submitted that the industry re-investment level is just a reference and what matters in assessing the appropriateness of capital investments is where assets are at with regard to the life cycle of their individual components:[78]

> **MR. STEPHENSON: At the moment, my question for you -- I didn't think there was a debate about this. You -- these two sentences say you have reinvested about at half the level of what industry experts say is reasonable. There's no other way of reading those two sentences.**
>
> **MR. MAZZA: One percent -- some companies invest less than 1 percent, some companies invest 1 percent, some companies invest 3 percent, depending on where they are in their life cycle of their assets and individual components.**
>
> **So it's a general statement, just to give the Board a flavour of what the ranges are with respect to investments. It wasn't designed for any other purpose.**

133. OPG's witness referred to Slide 26[79] of the Presentation, shown below, as demonstrating the cyclical nature of the hydroelectric investments:

[78] EB-2010-0008, Transcript Volume 2, Page 15, Lines 9-20.
[79] EB-2010-0008, Exhibit F1, Tab 1, Schedule 1, Attachment 1, Page 27.



134. The graph illustrates that 1999-2008 is the low spending period of the cycle. OPG's witness also noted the major components of the regulated assets identified on Slide 26:[80]

> **… I can refer you to the graph on page 26 on the same presentation, which, again, it's not related to the regulated assets, but you can see there is -- you can see there are two major components there to the regulated assets of investment cycles on Saunders and Beck 1 and Beck 2.**

135. Accepting OPG's evidence on the cyclical nature of investment levels, the PWU submits that given the ten years of annual re-investment levels for all hydroelectric assets at or below the low range considered by industry experts as reasonable, the proposed capital investments for the test years, excluding the Niagara Tunnel Project, would be expected to be on the upswing. This is particularly the case if the total

[80] EB-2010-0008, Transcript Volume 2, Page 14, Lines 10-15.

expenditures for the regulated assets follow the pattern of the overall hydroelectric assets as depicted in Slide 26. Capital expenditures provided in EB-2007-0905 and in this proceeding for the regulated hydroelectric facilities (excluding the Niagara Tunnel Project) from 2005 through 2012 are summarized in Exhibit 2 below. The trend suggests that the expenditures for the regulated hydroelectric facilities reflects the cycle illustrated for the total OPG hydroelectric expenditures (including regulated assets) as seen in Slide 26. The actual expenditures for 2005 through 2008 are lower than the actual expenditure for 2009, the budgeted amount for 2010 and the proposed amounts for the test years. However, the proposed expenditures for 2011 and 2012 are substantially lower than the 2010 budget amount. With the test years in the higher spending period of the cycle, the proposed spending might be expected to be closer to the 2010 budget amounts and therefore higher than proposed in the application.

Exhibit 2: Capital Expenditures ($M) Summary –
Regulated Hydroelectric (Excluding Niagara Tunnel Project)

Year	Niagara Plant Group	Saunders GS	Total
2005 Actual[81]	16.6	1.8	18.4
2006 Actual[82]	7.3	3.1	10.4
2007 Actual[83]	9.9	10.5	20.4
2008 Actual[84]	24.8	4	28.8
2009 Actual[85]	25.6	11.9	37.5
2010 Budget[86]	36.2	17.3	53.5
2011 Plan[87]	30.7	9.2	39.9
2012 Plan[88]	30.9	5.9	36.8

c. Assets Depreciating Faster Than Capital Additions

136. At the hearing, OPG agreed that over the five-year period 2007-2012 the prescribed hydroelectric assets are depreciating faster than OPG is making capital additions.[89] As a matter of fact, the regulated hydroelectric facilities' rate base has been on the decline at least since 2005. This fact is reflected in Exhibit 3 (below) which summarizes evidence on the regulated hydroelectric rate base provided in EB-2007-0905 and in the current proceeding. In addition, in a response to an interrogatory OPG includes the regulated hydroelectric assets "slightly lower rate base" as a reason for the

[81] EB-2007-0905, Exhibit D1, Tab 1, Schedule 1, Table 1.
[82] *Ibid*
[83] EB-2010-0008, Exhibit D1, Tab 1, Schedule 1, Table 1
[84] *Ibid*
[85] *Ibid*
[86] *Ibid*
[87] *Ibid*
[88] *Ibid*
[89] EB-2010-0008, Exhibit F1, Tab 1, Schedule 1, Table 1 and Transcript Volume 2, Page 17, Line 27 to Page 18, Line 2.

change in financing costs.[90] It is OPG's position that a declining rate base does not mean that OPG's investment levels are inappropriate because rate base increased in prior years, when OPG invested heavily.[91]

137. This explanation is consistent with OPG's witness' explanation of the cyclical nature of investment levels cited above. The PWU submits therefore, that both the investment cost evidence and the rate base evidence indicate that the test years are in a period of the hydroelectric investment cycle (both capital and OM&A[92]) when reinvestment levels and net plant should be on the rise or maintained at the 2010 levels. However, rather than being on the upswing, the forecast test year investment and rate base levels are declining from the 2010 levels.

138. The PWU acknowledges that this high level analysis may not have sufficient weight to require OPG to increase its proposed levels of spending in this application. On the other hand, the PWU submits that this analysis is consistent with and confirms its position that further cuts that would result from Board cost disallowance will have a negative impact on plant condition and reliability and net plant value.

[90] EB-2010-0008, Exhibit L, Tab 12, Schedule 1, Page 1, Lines 36-37.
[91] EB-2010-0008, Transcript Volume 2, Page 19, Lines 11-16.
[92] EB-2010-0008, Transcript Volume 2, Page 13, Lines 13-18.

Exhibit 3: Regulated Hydroelectric Rate Base ($M) Summary

Year	Gross Plant at Cost	Accumulated Depreciation and Amortization	Net Plant	Total Rate Base
2005 Actual[93]	4,362.4	384.0	3,978.4	4,001.3
2006 Actual[94]	4,380.4	446.5	3,933.9	3,957.3
2007 Actual[95]	4,396.5	507.8	3,888.7	3,911.1
2008 Actual[96]	4,416.8	569.5	3,847.3	3,871.5
2009 Actual[97]	4,438.6	631.2	3,807.4	3,834.0
2010 Budget[98]	4,485.0	693.6	3,791.4	3,815.7
2011 Plan[99]	4,538.0	756.7	3,781.3	3,803.4
2012 Plan[100]	4,585.5	820.2	3,765.3	3,787.4

d. OPG's 2010-2014 Corporate Business Plan Instructions

139. OPG's corporate planning process incorporates reductions in budget as set out in resource and performance planning guidelines specified in OPG's 2010-2014 Corporate Business Planning Instructions. These reductions include management commitment in the 2009-2013 Business Plan to reduce 2010 OM&A by $85 million. The hydroelectric business unit was asked to contribute $5M to the overall OPG cost reduction target of $85M and the regulated stations were allocated $1.2M of the total $5M hydroelectric cost reduction.[101]

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[93] EB-2007-0905, Exhibit B1, Tab 1, Schedule 1, Table 1
[94] EB-2007-0905, Exhibit B1, Tab 1, Schedule 1, Table 1
[95] EB-2010-0008, Exhibit B1, Tab 1, Schedule 1, Table 1
[96] EB-2010-0008, Exhibit B1, Tab 1, Schedule 1, Table 1
[97] EB-2010-0008, Exhibit B1, Tab 1, Schedule 1, Table 1
[98] EB-2010-0008, Exhibit B1, Tab 1, Schedule 1, Table 1
[99] EB-2010-0008, Exhibit B1, Tab 1, Schedule 1, Table 1
[100] EB-2010-0008, Exhibit B1, Tab 1, Schedule 1, Table 1
[101] EB-2010-0008, Exhibit A2, Tab 2, Schedule 1, Attachment 1, Page 10.

140. In addition, as noted by OPG's witness[102] the corporate planning instructions encouraged the business units, to the extent that they could, to take informed risks and decisions in terms of deferring certain work in consideration of a more acceptable level or rate requirement:

> **MR. STEPHENSON: Okay. And the question I have is: Would you agree with me that, generally speaking, there is always going to be a tension between top-down objectives and bottom-up objectives, in the sense that the engineers and the folks on the ground always want more money and more resources to do all of the good projects they think are required, and the people at the top want to impose constraints; fair?**
>
> **MR. HALPERIN: I think that is fair.**
>
> **MR. STEPHENSON: And the question I have for you is: What role, if any, does the business planning process play in achieving a compromise between the tension between those two competing visions?**
>
> **MR. HALPERIN: It is -- the role of the corporate planning process, as evidenced in the instructions, is to provide the higher level context facing the company within which the business units are expected to develop their business plans.**
>
> **To the extent that those instructions led off talking about the economic situation facing the province and its customers, it was trying to address that balance that needs to be made, and perhaps advocating that where there is always some gray area between how quickly perhaps you need to schedule to do certain projects to maintain your reliability or your investments in the plant and the ability to pay for them, <u>to the extent that we can take some informed risks and decisions in terms of deferring certain work if it will provide a more acceptable level or rate requirement, that's what we were encouraging them to do in these planning instructions.</u>**
>
> **The actual trade-off between the work that needs to be done to maintain system reliability or to address some of the other corners, as we call them, that is largely -- actually, completely addressed within the business unit process.** (Emphasis added)

141. The proposed hydroelectric budget therefore is an example of the result of a top-down budget cut imposed on the hydroelectric business unit at the corporate level and the business planning instruction to take informed risks and decisions in deferring work to provide a more acceptable rate level.

[102] EB-2010-0008, Transcript Volume 10, Page 64, Line 2 to Page 65, Line 8.

e. Hydroelectric Business Planning Process to Maintain/Enhance Value

142. OPG's evidence on the hydroelectric business planning process demonstrates how the determination and prioritization of investments and operating and maintenance expenditures for each facility is a result of its investment management involving annual engineering reviews and plant condition assessments (conducted on a cycle of approximately seven to ten years) performed to determine short-term and long-term expenditure requirements to sustain or improve each facility, and ensure continued safe operation.[103] As described in the evidence, OPG's planning approach is designed to identify necessary capital, and operating and maintenance projects for each facility, and direct limited corporate funds at the facilities that can best maintain or enhance the value of the hydroelectric business:

> **Business Units are requested to identify all capital and OM&A projects having cash flows within the Business Plan time horizon (2010-2014). The submitted projects must be prioritized to maximize value, while considering risks and OPG's business objectives as well as alignment with business unit strategies and facility Life Cycle Plans (as applicable).[104]**

143. The PWU submits that the hydroelectric business unit's planning process determines how best to maintain or enhance the value of the hydroelectric business and provides the basis for incorporating bottom-up considerations within the business planning process. It is this process that determines the informed risks and decisions on the deferral of specific work in consideration of rate impact minimization for consumers. The evidence points to the thoroughness of this process that involves a portfolio approach to investment management to maintain or enhance value of the assets. This process involves the use of tools and approaches to respond to the corporate business planning instructions:

> **Hydroelectric uses a structured approach to identify and prioritize projects for its investment program. Annual engineering reviews and plant condition assessments (conducted on a cycle of approximately seven to ten years) are performed to determine short-term and long-term expenditure requirements to sustain or improve each facility, and ensure continued safe operation. ….. This planning approach is designed to identify necessary capital, operating and maintenance expenditures for each facility, and direct limited corporate funds at the facilities**

[103] EB-2010-0008, Exhibit F1, Tab 1, Schedule 1, Page 3, Lines 12-24.
[104] EB-2010-0008, Exhibit A2, Tab 2, Schedule 1, Attachment 1, Page 14.

> **that can best maintain or enhance the value of the hydroelectric business and OPG**.[105]

144. In addition the hydroelectric business unit uses a streamlined reliability centred maintenance process that balances cost versus risk:

> **The concept of streamlined reliability centred maintenance dictates that the type and frequency of preventive maintenance applied to an individual component is determined based on the nature and consequences of failure (i.e., balance of cost versus risk).[106]**

145. OPG describes the engineering reviews as consisting of an Engineering Risk Assessment Program ("ERAP"):

> **This process systematically identifies, assesses and ranks the likelihood and consequence of safety, environmental and financial risks resulting from inadequate, obsolete or failed plant equipment or systems.[107]**
>
> **…**
>
> **Data to assess the condition and evaluate the risk of failures is obtained from sources such as current plant condition assessments, maintenance records, condition reports, inspection reports, test reports, operator, maintenance and engineering reports, incident reports, regulatory infractions, and developments in external utilities and industries. Conformance to applicable codes, acts and regulations and Hydroelectric Engineering Governance as well as reference to industry standards is also included in the assessment to demonstrate good engineering practice and due diligence.[108]**

146. Further OPG uses a detailed Plant Condition Assessment ("PCA") process that is a:

> …**multi-disciplinary, systems-based assessment of the physical condition of each hydroelectric generating station and that station's associated structures. The PCA provide determination of the required repair, rehabilitation, modification, or replacement of the assessed facilities' various components and/or systems, in order to maintain the safety, reliable production capability, and viability of the facility for the next 30 years. PCAs are repeated on a seven year cycle.[109]**

147. These hydroelectric business planning tools and approaches are used to comply with the corporate business planning instructions to prioritize projects to maximize value, while considering risks and OPG's business objectives as well as ensuring alignment with business unit strategies and facility Life Cycle Plans. The evidence

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105 EB-2010-2008, Exhibit F1, Tab 1, Schedule 1, Page 3, Lines 15-22.
106 EB-2010-2008, Exhibit F1, Tab 1, Schedule 1, Page 3, Line 30 to Page 4, Line 2.
107 EB-2010-2008, Exhibit L, Tab 11, Schedule 10, Page 1, Lines 29-31.
108 EB-2010-2008, Exhibit L, Tab 11, Schedule 10, Page 2, Lines 13-19.
109 EB-2010-2008, Exhibit L, Tab 11, Schedule 10, Page 2, Lines 26-31.

reveals the thoroughness of the hydroelectric business planning process that rely on the use of the tools described above i.e. streamlined reliability centred maintenance process; the ERAP; and, the PCA process.

148. The PWU submits that there has been no serious suggestion that any of the projects related to the ongoing reliability and value of the OPG's regulated hydroelectric generating stations, or the associated costs are not reasonable and prudent.

149. If the Board, contrary to the above submission, is swayed by other parties to disallow some portion of the proposed hydroelectric budget, rather than directing broad cuts, it should identify the evidence that has persuaded it to do so and the reasons for its decision to do so. Doing so is critical to OPG's understanding of that which in the Board's view is not a reasonable and prudent part of the proposed hydroelectric capital and OM&A budgets derived through thorough assessment of the aging assets, and that at the end of the 2010-2014 Business Plan will not have improved the condition of the stations as a result of a top-down budgeting process.

150. In conclusion, the PWU submits that the evidence is that the proposed 2011 and 2012 capital and OM&A budgets for the regulated hydroelectric assets are appropriate, albeit minimally so. OPG's proposed hydroelectric assets are aging yet at the end of the 2010-2014 business planning period, these assets will be in about the same condition as they are now. OPG's hydroelectric investment levels are cyclical and the evidence on historic investment and net plant levels indicates that OPG should be in the high investment period of its investment cycle in order to maintain the value and reliability of the assets. However, the proposed hydroelectric budgets are as proposed in consideration of rate impact.

151. OPG's corporate business planning process for the 2010-2014 Business Plan is a top-down approach that addresses financial requirements through limits on budget. The corporate business planning instructions provide for a bottom-up hydroelectric business planning process that prioritizes projects to maximize value, while balancing the risk of work deferral with rate requirement consideration. Therefore, the proposed hydroelectric revenue requirements for the test years, which are supported by a business planning process that incorporates tools and approaches that ensure the risk

II. NUCLEAR

Issue 4.4: Do the costs associated with the nuclear projects, and proposed for recovery, meet the requirements set out in O. Reg. 53/05? If not, were the additional costs prudent?

Issue 4.5: Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

Issue 6.3: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

152. In June 2006, the Government of Ontario directed OPG to begin feasibility studies on refurbishing its existing nuclear units.[110] Following this direction, in 2007 OPG began to undertake feasibility studies on the refurbishment of Darlington units.

153. OPG reported that current medium confidence estimates, based on Darlington's pressure tubes' fitness for service, predict that the Darlington reactors will reach the end of their current operating lives between 2018 and 2020. OPG stated that the goal of the refurbishment project would be to extend the service life of the units by an additional 210,000 equivalent full power hours ("EFPH"), to 2051. The refurbishment would involve an outage for replacement of life-limiting components, as well as maintenance or replacement of other components which are most effectively done during the refurbishment outage period.

[110] EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Attachment 5, Letter from the Government of Ontario to the OPA, June 16, 2006.

a. OPG's Request for Approval Related to the Darlington Refurbishment

154. The nature of the approvals that OPG is seeking from the Board in relation to the Darlington Refurbishment is as follows:

> **MR. BARRETT: Let me try and deal with those in two parts.**
>
> **In terms of the OEB, one of the gaps -- if I can use that word -- in the regulatory framework that governs OPG is that there is no parallel for a leave-to-construct application.**
>
> **So it is not clear to me how we would come to the Board to seek approval of a project like this.**
>
> **So you won't see that approval in our list of approvals. What you will see is the consequent impacts of our decision to proceed.[111]**

Further, OPG's witness explained:

> **MR. BARRETT: I would say it slightly different.**
>
> **I don't know how we get the Board's approval of the project. What we're seeking is approval of things that flow from proceeding with the project.**
>
> **Now, presumably, if the Board had a view that it was not reasonable to proceed with the project, then they would not approve the things that flow from that.**
>
> **So for example, if they thought that it wasn't reasonable to proceed with the project, that those things that are set out -- let me just find a reference -- the things that are set out in chart 1 -- sorry, in chart 1 on Exhibit D2, tab 2, schedule 1, the Board would not incorporate those adjustments into the revenue requirement. So they would essentially reverse those things if they took that view.[112]**

155. With regard to the expenditures related to the Darlington Refurbishment project, OPG is seeking Board approval for the recovery of the costs that flow from OPG's Board of Directors' decision to proceed with the project, that impact the test years' revenue requirement. According to OPG, the Board's concurrence with the prudence of proceeding with the project as approved by OPG's Board of Directors, would be implicit in the Board's approval of the 2011 and 2012 costs related to the Darlington Refurbishment, as prudent and reasonable. Specifically, OPG is seeking capital

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[111] EB-2010-0008, Transcript Volume 13, Page 80, Lines 16-26.
[112] EB-2010-0008, Transcript Volume 13, Page 83, Line 16 to Page 84, Line 2.

expenditures of $105.2 million and $255.8 million for 2011 and 2012, respectively.[113] In addition, OPG is seeking the following approvals:[114]

a. Approval of test period OM&A costs (which form part of the nuclear revenue requirement) of $5.9M and $4.5M in 2011 and 2012;

b. Changes in rate base, return on rate base, depreciation expense, tax expense and Bruce lease net revenues that result from the impacts of the service life extension, for purposes of calculating depreciation, and the change in the nuclear liabilities associated with Darlington Refurbishment;

c. An increase in rate base to reflect the inclusion of CWIP (i.e. $72.9 million in 2010, $105.2 million in 2011 and $255.8 million in 2012); and

d. The recovery of the difference between forecast 2010 non-capital costs associated with the Darlington Refurbishment project and the costs underlying the payment amounts established in EB-2007-0905.

156. OPG reported that its proposal in relation to the Darlington Refurbishment project would result in a revenue requirement decrease of $197.1 during the 2011-2012 test year period. The major drivers of the revenue requirement reduction are outlined by OPG as follows:

> **The major drivers of the revenue requirement reduction are lower depreciation expense as a result of extending the station's life and the consequent impact on the lower asset retirement obligation and asset retirement cost ("ARC"). The refurbishment also produces significant regulatory tax reductions. These reductions are partially offset by the return on the increased amount of ARC and OPG's proposal to include CWIP in rate base (see Section 10.2.3). Reductions in Bruce ARC, depreciation and accretion expense due to a lower percentage of common waste disposal costs being allocated to the Bruce facilities also work to reduce the revenue requirement.[115]**

b. Compliance with O.Reg. 53/05

157. The recovery of capital and non-capital costs, and firm financial commitments related to the Darlington Refurbishment project is governed by the provisions of O.Reg. 53/05, section 6(2)(4)(ii) which states:

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[113] EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Page 4, Lines 4-5.
[114] EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Page 4, Lines 7-20.
[115] EB-2010-0008, OPG Argument-in-Chief, Page 46, Lines 1-8.

> **4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,**
>
> > **i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or**
> >
> > **ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.**

158. Accordingly, as prescribed by section 6(2)(4)(ii) of O.Reg. 53/05, OPG is entitled to recover the costs related to Darlington Refurbishment if the Board finds that the past expenditures were "prudently incurred" and commitments for future expenditures were "prudently made".

c. Prudence Examination of Proposed Darlington Refurbishment Capital and OM&A Budgets

159. The evidence is that OPG's proposed 2011 and 2012 capital and OM&A budgets related to the Darlington Refurbishment project are reasonable and prudent.

160. The PWU addresses the issue of prudence review in relation to OPG's compensation in the Corporate Costs Section. The PWU submits that the same form of prudence review is to be applied to O.Reg. 53/05 section 6(2)(4)(ii) (i.e. the review of the prudence and reasonableness of OPG's proposed capital and OM&A budgets related to the Darlington Refurbishment for the period 2011-2012).

161. The reasonableness and prudence of those costs is reflected in the evidence outlined below.

i. OPG's Approach to Managing the Project

162. The PWU submits that OPG's approach to managing the project in phases is appropriate, and provides substantial safeguards that the financial and operational risks

associated with the project will be properly mitigated. The Darlington Refurbishment initiative is a major, multi-year undertaking. OPG reported that it will require several years of planning and preparation prior to the first outage in 2016. To mitigate the project risk, OPG is managing the project in phases (i.e. Project Initiation, Project Definition, Execution and Close-out) using a “gating” methodology. Under this approach, the project cannot proceed from one phase to the next without completing certain deliverables and providing an updated Business Case assessment on the total project. The Initial Project Execution Plan (“PEP”)[116] specifies a project release strategy under which OPG must develop a project plan and seek the release of funds in order to continue.

163. The approach OPG is using in managing the Darlington Refurbishment project is consistent with industry project management best practices. These practices are being applied by OPG with a higher degree of rigor than OPG has applied in past cases:

> **MR. REINER: …. What are we doing differently inside OPG on this project then we have done inside OPG on previous projects?**
>
> **So one of those things is that we are adopting industry best practices. And you referenced some of those, and those industry best practices are not new. They have been around for a while.**
>
> **But one of the lessons learned to us, we did not apply those same best practices to the same level of rigor in prior projects as we are to this project.**[117]

164. The experience gained by OPG from the Pickering A return to service project is illustrative of how OPG applied best practices when it developed a step-by-step plan and deferred the development of a point estimate for the project, until it had sufficient assurance as to both the regulatory scope and technical requirements of the project:

> **MR. REINER: Step-by-step, and also -- so in the past, and there was a line of questioning that -- a couple of days ago, that talked about Pickering A and an estimate for Pickering A that was done in 1999. So a point estimate was declared for the Pickering A return-to-service units.**
>
> **We have not declared a point estimate for this project without first completely understanding what the total scope of work is going to be. And so that is another key difference.**

[116] EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Attachment 2, Darlington Nuclear Refurbishment Project, Project Execution Plan.
[117] EB-2010-0008, Transcript Volume 8, Page 67, Lines 5-13.

> **So we have provided a range of estimates. Our point estimate will arrive when we have some assurances that we have a complete understanding of what that regulatory scope will require us to do, what the EA scope will require us to do, and what the technical components are that we need to replace to get the station to the end of its next life, prior to putting a release-quality estimate on the table.**
>
> **Now, on the Pickering unit 1 experience, we, in fact, did that. There was still an early estimate out there that dated back to 1999, but prior to seeking approval to proceed with the project, we did actually take all of that information from assessments that were done. And we came up with a revised estimate, which was that $900 million estimate, and then the project came in at $1.016 billion.**
>
> **So we got what I would say is relatively close to delivery on budget, and that is the practice that is being incorporated here.[118]**

ii. OPG's Decision to Proceed to Definition Phase

The Initiation Phase

165. The evidence demonstrates that, as part of its release strategy, OPG has been diligent in achieving Darlington Refurbishment's Initiation Phase (Release 1 and 2). The PWU notes that the work and the deliverables performed in the Initiation Phase provided support for the OPG Board of Directors' decision to proceed to the Definition Phase. The Government of Ontario has concurred with this decision.

166. In the Initiation Phase, OPG completed work in 2008 and 2009 supporting feasibility assessment. This work included technical assessments of the major systems, a component condition assessment ("CCA"), initial outage planning to determine the refurbishment reference schedule, and the development of initial project governance, including a PEP. According to its release strategy, in order to proceed to the Definition Phase – Preliminary Planning (Release 3), OPG was required to deliver (among other things) a Business Case Summary and Project Recommendation.

167. The Business Case submitted by OPG provides an Economic Feasibility Assessment[119] (the "Assessment") of the Darlington Refurbishment project. The Assessment includes a refurbishment project cost. In its pre-filed evidence, OPG reported that, based on the current level of planning as well as review of industry experience, the current projected cost of the refurbishment project is in the range of $6

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[118] EB-2010-0008, Transcript Volume 8, Page 67, Line 19 to Page 68, Line 16.
[119] EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Attachment 4, Economic Feasibility Assessment of Darlington Project, November 13, 2009.

billion to $10 billion (2009 dollars).[120] Based on the Assessment, OPG has a very high confidence that the project will result in a Levelized Unit Energy Cost ("LUEC") of less than 8¢/kWh (2009 dollars). OPG reported that the Business Case (i.e. the Assessment) was in support of the recommendation to its Board of Directors that the Darlington Refurbishment project should proceed to the Definition Phase.

The Definition Phase

168. The Initiation Phase came to completion with the approval of OPG's Board of Directors and the concurrence of the Government of Ontario to proceed with the Definition Phase. In November 2009, OPG's Board of Directors approved the Project Recommendation set out in the 2010-2014 Business Plan for Refurbishment, Projects and Support.[121] This approval included the nuclear refurbishment financial plan for the business plan period, the release strategy of the project and the work programs and budgets for the next phase. In a February 2010 letter, the Government of Ontario expressed its satisfaction with respect to the detailed technical regulatory and risk analysis performed by OPG regarding the Darlington Refurbishment Project and concurred with the November 2009 decision by the OPG Board of Directors.[122]

169. The evidence shows that OPG is taking the appropriate path in the implementation of plans related to the Darlington Refurbishment project. OPG's release strategy specifies the work programs and milestones for planning and preparation prior to the first outage in 2016 and for subsequent refurbishment outage execution of the Darlington units.

170. OPG reported that following OPG's Board of Directors' approval and the concurrence of the Province, it commenced the Definition Phase – Preliminary Planning (Release 3) of the Darlington Refurbishment Project in 2010. This phase covers preliminary planning work and contract strategy. Deliverables that are required to proceed to the next phase include the update of Business Case Summaries ("BSC") based on contracts with vendors, ready for issue.

[120] EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Page 8, Lines 10-12.
[121] EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Attachment 1, Nuclear Refurbishment, Projects, and Support Business Plan 2010 to 2014.
[122] EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Attachment 3, Letter from the Ontario Minister of Energy and Infrastructure to OPG, February 4, 2010.

171. In the Definition Phase – Engineering and Detailed Planning (Release 4) the milestone is to develop by 2014 a "release quality" estimate and a detailed cost and schedule. The deliverable is to produce a BCS with full project cost estimate to be presented to Senior Management, the Board of Directors and Shareholder, with a project execution strategy recommendation. Remaining releases cover outage preparation and refurbishment outage execution of the four units. A Full Release BCS providing updates to cost and schedule estimates will be required to commence refurbishment outage execution for each unit.

iii. The Appropriateness of 2011-2012 Proposed Capital and OM&A Budgets

172. OPG's proposed capital and OM&A budgets for the 2011-2012 test year period flow from the decision of its Board of Directors to proceed to the Definition Phase.

173. The PWU submits that the proposed capital and OM&A budget for 2011-2012 are supported by the budgets committed in the business plan. The PWU notes that the proposed capital and OM&A budgets included in OPG's proposed payment amounts for the test year period are consistent with the cash flows provided in OPG's Darlington Refurbishment Financial Plan as specified in the 2010-2014 Business Plan for Refurbishment, Projects and Support approved by OPG's Board of Directors in November 2009. The PWU also notes that the capital expenditures requested by OPG, in relation to the Darlington Refurbishment Project, are lower than the amounts reported in the 2010-2014 Business Plan for Refurbishment, Projects and Support because the Business Plan numbers include capitalized interest.[123]

174. As indicated above, OPG is proposing capital budgets of $105.2 million and $255.8 million for 2011 and 2012. These amounts include budgets related to the Preliminary Work Program. Major work programs cover project management and engineering costs and expenditures related to the completion of Environmental Assessment, and Integrated Safety Review. Budgets assigned for 2011-2012 also cover Preliminary Infrastructure (Campus Master Plan).

[123] EB-2010-0008, Exhibit L, Tab 10, Schedule 14, Lines 21-23.

d. The Economic Feasibility of the Project

175. As indicated above, OPG's Board of Directors' decision that the Darlington Refurbishment proceed to Definition Phase is supported by an Economic Feasibility Assessment delivered in the BCS.

176. Also as indicated above, based on the current level planning as well as review of industry experience, OPG estimated that the current projected cost of the Darlington Refurbishment project is in the range of $6 billion to $10 billion (2009 dollars). Based on the Economic Feasibility Assessment, OPG submitted that it currently has a very high confidence that the project will result in a LUEC of less than ¢8/kWh (2009 dollars).

177. The PWU agrees with OPG that the Darlington Refurbishment project will provide a competitive source of baseload generation. Combined Cycle Gas Turbine ("CCGT") generation is the relevant comparable alternative to nuclear baseload generation. The OPA noted that the Darlington Refurbishment LUEC of ¢6 to ¢8 (2009 dollars) per kWh is lower than the LUEC for CCGT estimated in the range of ¢10 to ¢15 per kWh. According to the OPA, other types of baseload resources such as new nuclear or renewable sources are also expected to have higher costs than Darlington Refurbishment.[124]

178. The PWU submits that the evidence supports OPG's LUEC estimate and the related sensitivity analysis based on the following information:

a. Condition assessments that were completed on the major plant components including re-tube and feeders, reactor, the turbine generator and the fuel handling were used in OPG's LUEC estimate:

> **MR. RUBIN: Did the plant condition assessment come in before the analysis was done that you have shared with us, for example, in the sensitivity chart we just discussed?**
>
> **MR. ROSE: So, it was under way when we did the analysis.**
>
> **Let me rephrase that. Parts of the plant condition assessment, specifically the major component portions, so the retube and feeder reactor, the turbine generator, the fuel handling, that is the major scope of this project. Those plant condition assessments were completed and they're informed in this analysis.**

[124] EB-2010-0008, Exhibit F2, Tab 2, Schedule 3, Attachment 2, Letter from OPA to OPG, April 1, 2010.

The balance of plant, that wasn't completed at that time. Obviously, as I said, it was completed in January. This report was prepared in November.

However, we did consider how that was going. We did consider the experience of Pickering B, and within our estimate we added a higher level of uncertainty to that one line item.

So we think that our estimate bounds that line item.[125]

b. The difficulties from other refurbishments were factored in the determination of the 36-month schedule, and, ultimately in the level of uncertainty that resulted in a ¢6 to ¢8 per kWh LUEC range:

In light of the fact that the GE Hitachi report was done when it was, as you say, probably begun in 2008 but done in 2009, and that to some extent, at least, the figure that we have talked about is based upon that information, were the problems at Point Lepreau and Bruce - but particularly I guess at Point Lepreau, maybe both, and Bruce -- known at that point? And to the best of your knowledge, were they factored in to the report and to your numbers?

MR. ROSE: So originally when we started our feasibility assessment, we landed on a schedule of approximately 27 months for the Darlington refurbishment project.

When we got into our analysis, and based on the experience from the other refurbishments going on, we did a fairly thorough analysis of reevaluating our schedule. So within our exhibit, we actually break down our schedule by different phases of the 36-month critical path.

We looked at the experience of defueling as an example. We looked at what Point Lepreau was projecting at that point. We looked at what Wolsong was projecting at that point based on our evidence from our working groups. We looked at our own analysis of what we could comfortably do under that phase, and we did do an analysis, a probabilistic analysis of that.

We did that for each component of the schedule. So we did update our feasibility assessment based on later information than what was in the original GE report.

We also, in our LUEC range, have built in a high degree of levels of uncertainty to allow us to -- as we get closer to that point estimate, I think that we will still be well within that 6 to 8 cent LUEC range.

So we do have levels of uncertainty based on what we know today. We have included that level of uncertainty in that 6 to 8 cent LUEC range. So we still have a very high confidence that we will fall within that range.[126]

[125] EB-2010-0008, Transcript Volume 7, Page 70, Line 21 to Page 71, Line 10.
[126] EB-2010-0008, Transcript Volume 8, Page 46, Line 3 to Page 47, Line 10.

c. With respect to the 65 per cent of the LUEC estimate that is attributed to OM&A costs and fuel costs,[127] the PWU submits that OPG has demonstrated the ability to operate Darlington to within acceptable performance measures. Accordingly, the amount of uncertainty on the OM&A and fuel cost component would be relatively low.

179. Proposed capital and OM&A budgets, relating to the Darlington Refurbishment project, flow from OPG's decision to proceed to the Definition Phase. The budgets related to the Darlington Refurbishment project are supported as reasonable and prudent by the evidence, including:

a. The 2010-2014 Business Plan for Refurbishment, Projects and Support approved by OPG's Board of Directors;

b. The Business Case showing that the Darlington Refurbishment Project is economically feasible and that it is a competitive source of generation compared to the cost of the relevant alternative for baseload generation;

c. The appropriate management of the Darlington Refurbishment project in phases using a gating methodology; and

d. The diligence process, as specified by OPG's release strategy in implementing the Darlington Refurbishment that resulted in the decision by the Board of Directors, and subsequent concurrence by the Ontario Government, to proceed to the Definition Phase.

180. The PWU therefore submits that the 2011 and 2012 Darlington Refurbishment Capital and OM&A budgets that flow from OPG's decision to proceed to the Definition Phase are reasonable and prudent. Further, the PWU submits that the budgets are consistent with O. Reg. 53/05 section 6(2)(4)(ii). For this reason, the PWU submits that the Board should approve the recovery of the costs related to the 2011 and 2012 capital and OM&A budgets for the Darlington Refurbishment project, as proposed by OPG.

[127] As indicated EB-2010-0008, Exhibit L, Tab 10, Schedule 3.

E. PRODUCTION FORECASTS

I. REGULATED HYDROELECTRIC

Issue 5.1: Is the proposed regulated hydroelectric production forecast appropriate?

181. OPG reported 2009 surplus baseload generation ("SBG") due to reduced electricity demand and an increase in available supply. According to OPG, in 2009 SBG was more prevalent in Ontario than it had been for many years. OPG's regulated hydroelectric production forecast that underpinned OPG's payment amounts, as approved by the Board in EB-2007-0905, did not incorporate the lower hydroelectric production attributable to SBG that OPG experienced in 2009. The PWU notes that the OPG's foregone revenue attributed to the lower hydroelectric production due to SGB is not currently recovered through a variance account mechanism.

182. OPG expects to continue to experience significant SBG in the period 2011-2012 and incorporates a Forecast SBG Adjustment in its hydroelectric production forecast for the 2011-2012 test year period. The PWU submits that if the Forecast SBG Adjustment were excluded from OPG's hydroelectric production forecast it would result in an unrealistically high hydroelectric forecast; and, ultimately, in an unfairly lower payment amount for OPG's regulated hydroelectric facilities.

183. OPG submitted a Forecast SBG Adjustment of 0.5 TWh in 2011 and 0.8 TWh in 2012. OPG stated that the main driver of this adjustment is the planned expansion of renewable wind generation in Ontario. OPG reported that new wind generation accounts for 0.8 of the 1.3 TWh adjustment reported for the 2011-2012 test year period.[128]

184. There is uncertainty around new wind generation development. In its latest 18 Month Outlook, the IESO's committed and contracted generation resources totals 1,235 MW for the period September 2010 – February 2012, including 858 MW related to Grid-connected FIT Projects.[129] Also, in its latest bi-weekly FIT and MicroFIT Report the Ontario Power Authority ("OPA") reported 1,531 MW related to wind generation contract

[128] EB-2010-0008, OPG Argument-in-Chief, Page 12 of 103, line 5-7.
[129] EB-2010-0008, Exhibit K1.4: 18-Month Outlook of IESO, August 2010. Table 4.2: Committed and Contracted Generation Resources.

executed projects. However, there is an additional 5,183 MW related to projects awaiting the Economic Connection Test.[130] This suggests that new wind generation could be higher than what OPG is expecting.

185. In conclusion, the PWU submits that exclusion of the SBG adjustments of 0.5 TWh in 2011 and 0.8 TWh in 2012 from OPG's hydroelectric production forecast results in an unrealistically high hydroelectric production forecast. The effect of denying the proposed SBG adjustments would be akin to approving a revenue requirement while minimizing OPG's ability to realize it.

186. The PWU disagrees with the position of Board Staff in its written submissions that the Forecast SBG Adjustment results in OPG being "indemnified" from the financial impacts of SBG.[131] This will only be the case if SBG is at or below OPG's forecast. In the event SBG is higher than forecast by OPG (which is a real possibility), it remains at risk of under recovery.

187. The PWU agrees with OPG that if the Board has concern with respect to the level of the Forecast SBG Adjustment, a variance account - tracking the over/under recovery of OPG's revenue that would result from the discrepancies between actual and forecast SBG volumes should be established. The PWU also agrees that given the fact that SBG conditions are beyond OPG's control, the establishment of a variance account for SBG is a fair measure providing protection to both ratepayers and OPG against the risk of over/under recovery revenues resulting from SBG.

II. NUCLEAR

Issue 5.2: Is the proposed nuclear production forecast appropriate?

188. OPG's actual nuclear production from 2005-2008 has been less than forecast by, on average, 3.5 TWh/year. This has occurred largely as a result of forced outages and forced extensions to planned outages due to major unforeseen events. OPG has therefore "adjusted its production forecast methodology in the 2010-2014 Business Plan

[130] OPA Bi-weekly FIT and microFIT Report, Data as of November 22nd, 2010 http://fit.powerauthority.on.ca/Storage/102/11173_Bi-Weekly_FIT_and_microFIT_Report_November_22%2C_2010.pdf
[131] EB-2010-0008, Board Staff Submissions, Page 83.

to include a 2.0 TWh per year allowance for major unforeseen events on the expectation that these types of events will occur in the future."[132]

189. Since OPG has established a stretch performance target for management that is 2.0 TWh higher than the 2010-2014 Business Plan production forecast, the 2.0 TWh allowance for major unforeseen events does not minimize management's incentive to maximize nuclear production.

190. OPG submits, and the PWU agrees, given the "rigour and thoroughness of OPG's Integrated Plan and analysis of major unforeseen events, the nuclear production forecast that underpins OPG's Business Plan is the most accurate forecast of test period nuclear production and should be approved. The evidence supports the change in methodology that includes a 2 TWh adjustment for major unforeseen events.

191. In conclusion the PWU submits that exclusion of the 2 TWh major unforeseen events adjustment from OPG's nuclear production forecast results in an unrealistically high nuclear production forecast. The effect of denying the 2 TWh adjustment would be akin to approving a revenue requirement while minimizing OPG's ability to realize it.

F. OPERATING COSTS

I. NUCLEAR

Issue 6.7: Are the proposed expenditures related to continued operations at Pickering B appropriate?

192. The PWU submits that OPG's proposed expenditures related to the Pickering B Continued Operations initiative for the test year period 2011-2012 are appropriate. OPG's evidence demonstrates that:

a. The project is of high value to the Ontario electricity system; and

b. OPG's proposed incremental work and related budgets for this project for the test year period 2011-2012 are supported by a business case which includes a risk mitigation strategy.

[132] EB-2010-0008, Exhibit E2, Tab 1, Schedule 1, Page 11, Lines 9-15.

193. The nominal end-of-service for Pickering B is based on the nominal life of the key major component (i.e. fuel channels) and is projected to occur when units reach nominally 210,000 EFPH, which is equivalent to 30 years of operation at approximately 80 per cent capability factor. The nominal end-of-life of the Pickering B units were projected to be in 2014 for Unit 5 and 6 and in 2016 for Unit 7 and 8. The Pickering B Continued Operations aims at extending the nominal operating end-of-service life of Pickering B nuclear generating station to 2020. Through this initiative, OPG would be able to operate Pickering B units for a further four calendar years (i.e. Unit 5 and 6 from 2014 to 2018 and Unit 7 and 8 from 2016 to 2020).

194. The Pickering B Continued Operations initiative is a key component of OPG's 2010-2014 Business Plan. The Pickering B, Pickering A and Darlington nuclear generating stations are all near their expected nominal end-of-service lives. The PWU submits that Pickering B Continued Operations will have a key role in the future of OPG's nuclear operations as the project impacts not only Pickering B, but also the future operation of Pickering A and Darlington. As the evidence indicates, the impact of the Pickering B Continued Operations is as follows:

a. OPG is not planning to operate the two Pickering A units with Pickering B shutdown.[133] Pickering A's operation is linked to Pickering B through shared common systems. OPG submitted that while it would not be impossible to operate Pickering A after end-of-life of Pickering B, OPG would not attempt to operate Pickering A with Pickering B shutdown at this time;[134] and

b. Achieving Continued Operations at Pickering B will supply baseload generation until 2020, a period during which a portion of the Darlington Refurbishment project will be ongoing. This timing creates a positive economic benefit to Ontario's electricity system by adding power supply in a period of shortfall in capacity (i.e. 2014-2020). In addition, it will provide OPG with flexibility to smooth the redeployment of experienced skilled

[133] EB-2010-0008, Exhibit F2, Tab 2, Schedule 3, Page 5 of 13.

[134] EB-2010-0008, Exhibit F2, Tab 2, Schedule 3, Attachment 1, Business Case - Pickering B Continued Operations, Appendix C, Page 7 of 18.

staff to the refurbished Darlington units, mitigating the cost of recruiting and training new staff.

195. OPG reported that the Pickering B Continued Operations initiative follows from OPG's decision not to refurbish Pickering B. The evidence is that with certain incremental maintenance, inspections and analytical programs, Pickering B units could be operated safely and reliably beyond 210,000 EFPH.

196. This initiative requires incremental work effort over the period 2010-2014. The Business Case for Pickering B Continued Operations (the "Business Case") provides an estimated cost of $190.2M over the period 2010-2014.[135] According to Appendix C of the Business Case, the cost attributable to the period 2010-2012 is estimated at $106.4M.

a. The Economic Benefit of the Pickering Continued Operations Initiative

197. The PWU submits that the Business Case[136] shows a high positive value to the Ontario electricity system and supports the project, based upon:

a. OPG's Net Present Value ("NPV") analysis, which includes a sensitivity analysis; and

b. OPA's analysis comparing the cost of incremental generation that results from extending the nominal end-of-life for four more years to the cost of alternative generation in the Ontario electricity market that would be required to replace production resulting from Pickering B Continued Operations.

[135] EB-2010-0008, Exhibit F2, Tab 2, Schedule 3, Attachment 1, Business Case - Pickering B Continued Operations, Page 17 of 18.

[136] EB-2010-0008, Exhibit F2, Tab 2, Schedule 3, Attachment 1, Business Case - Pickering B Continued Operations.

i. OPG's NPV Analysis

198. OPG's Business Case indicates that extending the nominal end-of-service life of Pickering B units for four additional years provides substantial value to the Ontario electricity system, estimated to have an NPV of $ 1.1billion (2010 dollars).

199. The extension of the nominal end-of-life of Pickering B does not only result in incremental production for Pickering B as a result of its operation beyond the 210,000 EFPH but, as indicated above, has beneficial implications in the operation of Pickering A Units 1 and 4. OPG has reported that when there are less than two Pickering B units in operation, there are significant technical and economic challenges to the economic operation of the Pickering A units.[137] Accordingly, extending the operation of Pickering B units to 2018/2020 would also result in incremental production from Pickering A. OPG reported that as a result of Pickering B Continued Operations, the net contribution of additional power from Pickering A and Pickering B to be supplied during the period 2010-2020 is estimated at 105 TWh.

200. The PWU submits that the Business Case and Undertaking J5.1 (non-confidential), supports OPG's assessment of the Pickering B Continued Operations initiative, with an NPV of $1.1 billion (2010 dollars). The PWU submits this is a reasonable estimate of the NPV on the basis that:

a. The estimate represents the NPV of the incremental energy that would result from the extension of the operation of Pickering B units to 2018/2020 compared to the alternative of Pickering B units shutdown in 2014/2016;

b. The estimate uses and extrapolates 2010-2014 Business Plan costs and performance, including the Continued Operations costs and performance impacts of items such as Spacer Location and Relocation ("SLAR") costs, enhanced water-lancing costs and increased planned outage days;

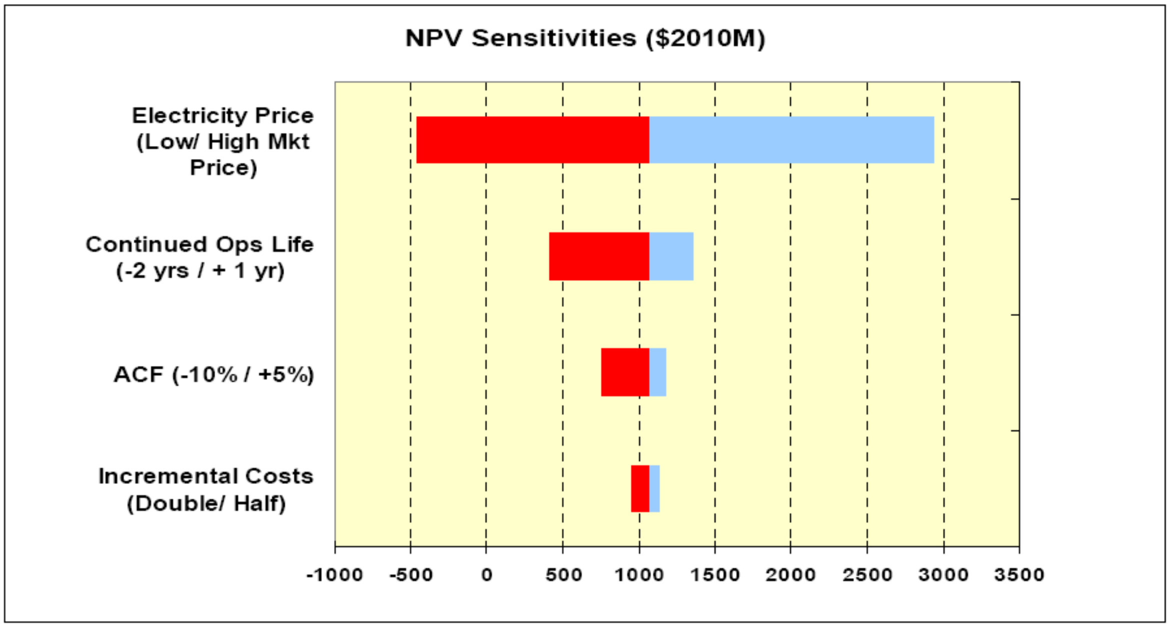
c. It assumes an increase in forced loss rates as units' lives are extended beyond the current nominal end-of-life; and

[137] EB-2010-0008, Exhibit F2, Tab 2, Schedule 3, Page 5.

d. It relies on a base case electricity price regime scenario which reflects OPG's 2009 median assumption regarding future Ontario system development, gas prices, etc. The PWU submits that the base case electric price regime scenario is reasonable based on OPG's sensitivity analysis, which is discussed below, and the consideration of alternative price regime scenarios, the PWU submits that the base case electric price regime scenario is reasonable.

OPG's Sensitivity Analysis

201. OPG's NPV sensitivity analysis provided in the Business Case[138] is as follows:



As shown in the above chart, the NPV is sensitive to electricity price, and not particularly sensitive to other factors.

202. OPG provided calculations of NPV for alternatives based on forecast costs and revenues (performance and assumed electricity price). OPG reported that the results were calculated from an Ontario System perspective based on its assessment of the value of incremental energy and capacity to the Ontario system (i.e. OPG's 2009

[138] EB-2010-0008, Exhibit F2, Tab 2, Schedule 3, Attachment 1, Business Case – Pickering B Continued Operations, Page 9 of 18.

forecast of System Energy Values (“SEV”)).[139] In Undertaking J5.1 (non-confidential) OPG provided NPV for base, low and high electricity price regime scenarios[140] as summarized in the Exhibit 4 below:

Exhibit 4

Scenario	NPV (M2010 $)
PCO SEV_Base – PnoCO SEV_Base	1,107
PCO SEV_Low - PNoCO SEV_Low	-398
PCO SEV_High – PnoCO SEV_High	2,863

203. Assumed electricity prices incorporated in the three above scenarios can be derived from dividing gross benefits by energy volumes, as reported in Undertaking J5.1 (non-confidential), as presented in Exhibit 5 below. From the worksheet the PWU infers that the calculated electricity prices are real: i.e. unescalated by inflation and expressed in 2009 constant values.

204. In Argument the Board Staff submitted that OPG’s estimate of the benefits associated with the Pickering Continued Operations is significantly overstated. Specifically, the Board Staff expressed concern with respect to the assumed Unit Capability Factor (“UCF”).[141] The PWU notes that OPG’s NPV analysis provided in Figure 2[142] suggests that the NPV is still significantly positive even for the lower end of the range displayed for Average Capability Factor.

[139] EB-2010-0008, Exhibit F2, Tab 2, Schedule 3, Attachment 1, Business Case – Pickering B Continued Operations, Page 8 of 18.
[140] EB-2010-0008, Undertaking J5.1, Attachment 1 (non-confidential).
[141] EB-2010-0008, Board Staff Argument. Pages 63-64.
[142] EB-2010-0008, Exhibit F2, Tab 2, Schedule 3, Attachment 1, Business Case – Pickering B Continued Operations, Figure 2. Page 9 of 18.

Exhibit 5

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PCO SEV_Base - PNoCO SEV_Base											
Energy (TWh) – Nuc –Pick	-0.33	-1.21	-0.66	-1.09	4.53	17.29	22.19	21.96	19.11	16.43	6.67
Gross Benefit (C$M)	-13	-47	-25	-44	197	965	1485	1589	1504	1260	615
Electricity Price Estimate (C$/MWh)	39.39	38.84	37.88	40.37	43.49	55.81	66.92	72.36	78.70	76.69	92.20
PCO SEV_Low - PNoCO SEV_Low											
Energy (TWh) – Nuc --Pick	-0.33	-1.21	-0.66	-1.09	4.53	17.29	22.19	21.96	19.11	16.43	6.67
Gross Benefit (C$M)	-8	-34	-18	-32	133	638	934	987	929	756	318
Electricity Price Estimate (C$/MWh)	24.24	28.10	27.27	29.36	29.36	36.90	42.09	44.95	48.61	46.01	47.68
PCO SEV_High - PNoCO SEV_High											
Energy (TWh) – Nuc --Pick	-0.39	-1.33	-1.20	-1.40	4.16	16.96	21.95	21.88	19.49	16.66	6.91
Gross Benefit (C$M)	-20	-68	-68	-86	270	1382	2190	2326	2178	1835	915
Electricity Price Estimate (C$/MWh)	51.28	51.13	56.67	61.43	64.90	81.49	99.77	106.31	111.75	110.14	132.42

205. As can be seen in the three electricity price regime scenarios, assumed electricity prices display an increase after 2014. The higher prices after 2014 are consistent with what would be expected if Darlington NGS and, possibly, Bruce B NGS were out of service for refurbishment.[143] Prices are expected to increase in 2020. The PWU notes that the increase is explained by the lower production from Pickering A and Pickering B in 2020, consistent with OPG's proposed end-of-service life of Pickering B between 2018 and 2020. According to J5.1 (non-confidential), OPG assumed that the production for Pickering A and Pickering B would reduce by 9.7 TWh in 2020 relative to 2019. It is evident that the withdrawal of such volume of energy from the market will necessarily result in a higher price. As can also be seen in the table above, in the base scenario, the electricity price for 2010 is 39.39/MWh. The PWU notes that this is the

[143] EB-2010-0008, Exhibit F2, Tab 2, Schedule 3, Attachment 2, Letter from the OPA to OGG regarding Pickering NGS Continued Operation and Darlington Refurbishment, April 1, 2010. In this letter the OPA has also contemplated that, in addition to Darlington, Bruce B may to be out of service for refurbishment after 2014.

electricity price assumed in the base case with a NPV of $1.1 billion. The PWU also notes that a price of $39.39/MWh is similar to the actual average HOEP for the period January-October 2010. The PWU submits that these are very reasonable assumptions with respect to future electricity prices that permit a higher degree of confidence with respect to the magnitude of the positive NPV from the Pickering B Continued Operations project.

	Arithmetic Ave	**Weighted Ave**
Jan-10	37.4	38.25
Feb-10	35.9	36.43
Mar-10	28.22	28.76
Apr-10	30.83	31.71
May-10	38.77	40.39
Jun-10	40.36	41.58
Jul-10	50.83	54.29
Aug-10	44.41	46.75
Sep-10	32.91	34.3
Oct-10	29.39	30.18
Average Jan-Oct 2010	36.90	38.26

Source: IESO Market Summaries.
http://www.ieso.ca/imoweb/pubs/marketReports/download/HOEP_20101203.csv

206. Concern was raised during the hearing with respect to the low scenario in which the NPV reaches -$398 million (2010 dollars). The PWU submits that this scenario is not a realistic one. This is illustrated by the price for 2020 ($47.68/MWh) given the higher prices expected after 2015 as shown in Exhibit 5, which would be even lower than OPG's current payment amount. The Board therefore should not assign any, or very low, weight to this scenario.

207. OPG also reported that in performing the sensitivity test, assuming a price equivalent to OPG's current regulated nuclear rate of $53/MWh, the value of the incremental production to the Ontario electricity system was estimated at $70 million.[144] OPG indicated that the $70 million is lower than the $1.1 billion, because the current rate that OPG receives for its nuclear facilities is lower than the expected price of

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[144] EB-2010-0008, Exhibit F2, Tab 2, Schedule 3, Attachment 1, Business Case - Pickering B Continued Operations, Appendix C, Page 9 of 18.

replacement power. The PWU submits that OPG's evidence of the very large positive NPV associated with the Pickering B Continued Operations project indicates the high value it provides to Ontario's electricity system and the large benefit to consumers.

ii. The OPA Analysis

208. The OPA has reported that substantial benefits could arise from the Pickering B Continued Operations initiative during the period 2014-2020. As indicated above, the OPA noted that during this period generating units at Darlington and possibly at Bruce B are expected to be out of service for refurbishment, and gas-fired generation would therefore be on the margin for many hours.

209. Using information provided by OPG, the OPA derived a unit cost of about $51(2010 dollars)/MWh for the incremental energy produced by Pickering A and B during the period 2010-2020, as a result of extending the nominal end-of-life of Pickering B by four years.

210. The OPA's cost of $51(2010 dollars)/MWh was derived using data consistent with that reported and used by OPG in its Business Case for the Pickering B Continued Operations initiative.

211. The PWU submits that the unit cost of $51(2010 dollars)/MWh is supported by information displayed by OPG in its letter to the OPA which appears to have been derived in the following manner:

> *Unit Cost for Pickering B Continued Operations = Total Continued Operations / Incremental Generation*
>
> *Unit Cost for Pickering B Continued Operations = 5,382 (M2010$) / 104 TWh = 51 (2010$/MWh)*
>
> Where,
>
> - *Total Continued Operation Cost = Pickering A and B OM&A plus Fuel Cost* for the period 2014-2020 + *Cost to Enable Continue Operation during 2010 -2013*
> - *Total Continued Operation Cost = 5,242 (M2010$) + 140 (M2010$) = 5,382 (M2010$)*

212. The PWU notes that Pickering A and B OM&A + Fuel Cost of $5,242M (2010 dollars) reported by the OPA is consistent with data provided by OPG in Undertaking J5.1 (non-confidential).

213. With regard to the Cost to Enable Continued Operations, the $140 million (2010 dollars) cost covers the portion of the total cost to be incurred during the period 2010 - 2013. OPA reported a total cost to enable continued operations of $184 million (2010 dollars) for 2010-2020. As indicated in interrogatory L-01-067 and Undertaking J5.7 (non-confidential), the $184 million figure represents the cost of the Continued Operations Initiative in 2010 dollars (i.e. unescalated), whereas the $190.2 million, as reported in the Business Case, is expressed in dollars of the year (i.e. escalated).

214. The OPA has indicated that substantial system benefits could arise from the Pickering B Continued Operations initiative by replacing generation from gas-fired resources or similarly priced imports. The OPA illustrates that for a gas price in the range of $6/MMBtu to $8/MMBtu, an assumed carbon price of $20/ton, and a typical heat rate of 7,000 MBtu/MWh, the variable operating cost for a typical gas-fired generation would be in the range of $52/MWh to $66/MWh.

215. The OPA considers gas-fired generation to be a relevant existing alternative resource generation in the Ontario electricity market to replace nuclear baseload generation. However, it is an expensive source of baseload generation compared to OPG's nuclear generation. The benefit of extending the end-of-life of Pickering B for four more years relies on the lower unit cost estimated for this initiative relative to the cost of immediately available alternative generation in the Ontario electricity market. The OPA estimates that overall system benefit could be up to $1.6 billion (i.e. 104 TWh X $15/MWh). This system benefit will result in total bill mitigation for Ontario consumers. The power that is going to have to replace the retired nuclear plant is going to be, more likely than not, more expensive. This is the source of the positive NPV.[145]

216. In its submissions, Board Staff is critical of OPG's use of CCGT as the probable source of replacement power for the purposes of the calculating the NPV of the project. It is submitted that this is an entirely reasonable assumption for OPG to use. The same

[145] EB-2010-0008, Transcript Volume 4, Page 47, Lines 11-23.

assumption was used by the OPA in the IPSP. It is not apparent what other generation source would be used as the assumed source of replacement of baseload generation. Board Staff makes no suggestion of what a more cost effective source of replacement of baseload generation might be.

Other Benefits of Pickering B Continued Operations

217. The PWU notes that there are other benefits, reported by OPG in its Business Case, not included in the NPV analysis. These benefits include:

a. Staffing flexibility to smooth the reassignment of experienced skilled staff to the refurbished Darlington units and possibly eventually to new Darlington units, mitigating the cost of recruiting and training new staff;

b. Socio-economic impacts within the Durham region; and

c. Deferral of new transmission infrastructure in the Oshawa area, as reported by OPG that would be necessary if the Pickering stations were shut down.

b. Managing the Risk to Achieve Pickering B Continued Operations

218. OPG's proposed incremental work and related budgets for the Pickering B Continued Operations initiative are supported by the Business Case and a risk mitigation strategy. For each identified risk, OPG determined a mitigation strategy and established the probability of success (i.e. very high, high, minimum and low) in achieving Pickering B Continued Operations for 2 or 4 years.[146] The proposed budgets associated with the Pickering B Continued Operations initiative relate to the work required to mitigate the risk to achieve Pickering B Continued Operations.

219. Major risks identified by OPG in the Business Case are the following:

a. Technical/Fitness Risk:

This is the risk that a major component does not continue to meet fitness-for-service continue requirements. OPG has identified the technical risk for each major component. A major risk was identified around aging mechanism that may impact the integrity of the pressure tubes, i.e. by

[146] EB-2010-0008, Exhibit F2, Tab 2, Schedule 3, Attachment 1, Appendix A, Page 13 of 18.

contact with the calandria tubes. The integrity of pressure tubes require assurance that the spacers between the calandria tubes and the pressure tubes are in the correct position. OPG has assigned medium probability of success that pressure tubes avoid contact with calandria tubes over a period of four years. Also, medium probability of success has been assigned for preventing the increase in the concentration of hydrogen in the pressure tubes for four years. A high probability of success has been assigned to the technical risks associated with other major components (e.g. reactor components, boilers and feeders).

b. Regulatory Risk:

OPG has submitted that there is a risk that a proposed disposition by the CNSC or that a change to regulatory limits result in OPG being unable to demonstrate feasibility of continued operations. OPG has assigned a medium probability of success in relation to the risk on changes on the Integrated Safety and Environmental Assessment covering mandatory regulatory upgrades to support continued operations for four years.

220. The risk analysis led OPG to propose to undertake the following incremental work during the test year period 2011-2012:

a. Additional Maintenance:

This involves selected and well-defined additional maintenance to improve the material condition of the plant and to ensure the continued fitness-for-service of the plant's major components beyond 210,000 EFPH.

b. Life Cycle Management Requirements:

This involves additional inspections to confirm component fitness-for-service, increased SLAR activities, increased pressure tube inspections, feeder inspections and a limited number of feeder replacements, boiler tube inspections and boiler water cleaning activities.

221. OPG has managed diligently and prudently the risks of the Pickering B units Continued Operations. In managing the risk to achieve Continued Operation for four

more years, the incremental work to be undertaken by OPG is consistent with the recommendations from a detailed CCA of 70 systems, that was completed in the first half of 2007. OPG has reported that, "the recommendations from the CCAs were assessed to determine the potential impact on costs and reliability in the Continued Operations period. The conclusion of the assessment was that, with the implementation of increased preventive maintenance programs and additional inspection there would be minimal risks to equipment over Continued Operations period".[147]

222. The timing of this initiative is critical. The incremental work proposed to be undertaken over the 2011-2012 test year period cannot be deferred to 2012:

> **MR. STEPHENSON: Okay. Let me then just come back to the proposal. As I understand it, you've got a relatively short -- sorry, relatively small window of time in order to do the work you need to do in order to permit this continued operation; is that right?**
>
> **MR. PASQUET: That's correct. We have -- we have basically two fundamental blocks of work, one which is a study which is going to ultimately determine the available life in the pressure tubes, and that is the fuel channel management study which is referenced in the evidence.**
>
> **And the second block of work, which is work that we need to perform now to enable us to achieve the extra four years, some of the work that we will do in the next couple of years will actually provide data to support the fuel channel life management program; other work which is to ensure that we preserve the asset, for example, such as boilers, to allow us then to achieve the additional four years.**
>
> **So there is a fairly tight window, as you correctly said, to allow us to get this body of work done. That then enables us to make the decision around the additional four years.**
>
> **MR. STEPHENSON: And am I right that if you don't do this work during the test period - that is, by 2012 - then the decision is made for you? You are not doing it at all, and these units are going to start closing in 2014. That's the bottom line?**
>
> **MR. PASQUET: That's the bottom line.[148]**

223. The evidence is that the incremental production that would result from extending Pickering B operation by four years is of high value to Ontario's electricity system. Specifically, the evidence is that the project is likely to have a large positive NPV. In addition, the unit cost related to the incremental production that would result from Pickering B Continued Operations is competitive relative to the variable cost associated

[147] EB-2010-0008, Exhibit F2, Tab 2, Schedule 3, Attachment 1, Business Case – Pickering B Continued Operations, Page 6.
[148] EB-2010-0008, Transcript Volume 4, Page 49, Line 15 to Page 50, Line 14.

with the alternative baseload resource generation. As such, the project will mitigate total bill impact for Ontario consumers for the four-year period, at least relative to the alternative generation sources.

224. OPG’s proposed incremental work and the related budgets for the Pickering B Continued Operations initiative are supported by the business case and a risk mitigation strategy. Further, OPG has been managing the risk related to the Continued Operations in a prudent and diligent manner; the proposed work for the test year period 2011-2012 is consistent with the conclusion of the CCAs completed in 2007, which indicates that with increased preventive maintenance and additional inspection, there would be minimal risk to the equipment over the Continued Operations period.

225. Critically, the realization of the benefits of the Pickering B Continued Operations is contingent on the timeline proposed by OPG. OPG’s business case makes it clear that deferral of incremental work to be undertaken over the 2011-2012 test year period (i.e. additional maintenance and additional inspections to confirm component fitness-for-service) to reduce the risk of not achieving Pickering B Continued Operations renders the project no longer feasible.

226. The PWU submits that OPG’s proposed expenditures related to the Pickering B Continued Operations are reasonable and prudent and that the Board should approve the costs as proposed.

II. CORPORATE COSTS

Issue 6.8: Are the 2011 and 2012 human resource related costs (wages, salaries, benefits, incentive payments, FTE’s and pension costs) appropriate?

a. The Collective Agreements

227. With respect to the compensation costs associated with PWU represented staff, the compensation rates for these employees is fixed until March, 2012 in accordance with the provisions of the existing collective agreement, entered into effective April 2009.

228. The compensation rates for PWU represented staff for the balance of the test period after March 2011 will be determined by future collective bargaining. For the

purposes of this proceeding, OPG has forecast that compensation rates for PWU represented staff will continue to escalate at 3 per cent for the balance of the test period.[149]

229. In order to determine whether the compensation rates for PWU represented staff claimed by OPG for the test period are reasonable and prudent, it is necessary for the Board to consider two questions:

a. Were the current compensation rates, reasonable and prudent when the present collective agreement was entered into in April 2009; and

b. Is OPG's forecast of the escalation in compensation rates for PWU represented staff for the balance of the test period after March 2012 reasonable and prudent?

230. In determining the reasonableness and prudence of costs currently being incurred on the basis of past commitments it is necessary for the Board to undertake a "prudence review" of that past commitment. The scope of this analysis was described

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[149] EB-2010-0008, Transcript Volume 9, Page 18, Line 11 to Page 19, Line 10. OPG is forecasting that, in aggregate, there will be an additional 1% increase in compensation rates for PWU represented staff by virtue of the progression of some staff through the PWU pay grid.

> MR. STEPHENSON: Correct. Am I right, then, that the 1 percent amount -- obviously the promotions is an entirely different question, but on the progression side, the reason why there is a net increase there is because there are more people that are still progressing on the grid than there are new entrants each year? For every retiree that is leaving, there are a lot more people in the six- or eight-year band that are still progressing each year?
>
> MS. IRVINE: The answer to your second comment I think is correct. I am still unsure about the previous one.
>
> MR. STEPHENSON: Well, I am assuming -- and this may be inaccurate, but if we assume for a moment that for each retiree there is a new entrant, and I appreciate that is not entirely accurate, but for the purposes of this example, let's assume it is. So you are having a person who is at the top of the grid leave and a person at the bottom of the grid come in; correct?
> MS. IRVINE: Hmm-hmm.
>
> MR. STEPHENSON: But at the same time, you've got everybody that was at steps 1 through 6 or 1 through 8 ratcheting up one more step each year; correct?
>
> MS. IRVINE: Yes. They're progressing through the system.
>
> MR. STEPHENSON: And there is a lot more people in that 1 through 6 or 1 through 8 group ratcheting up each year than there is new entrants in each year?
>
> MS. IRVINE: Yes.

by the Divisional Court in *Enbridge Gas Distribution v. Ontario Energy Board*[150] as follows:

> **Expenditures are deemed to be prudent, in the absence of some evidence suggesting the contrary. However, costs that are found to be dishonestly incurred, or which are negligent or wasteful losses, are excluded from the legitimate operating costs of the utility in determining rates that may be charged. The examination of whether an expenditure was prudent must be based on the particular circumstances at the time the decision to incur those costs was made. That is so even if in hindsight it is obvious the decision was a bad one.[151]**

231. On appeal to the Court of Appeal, the Court confirmed that on a prudence review, utility expenditures are entitled to the presumption of prudence, unless challenged on reasonable grounds. Unless the presumption is rebutted by evidence, no further inquiry is required. In the event the presumption is rebutted, the prudence of the expenditures in question must be assessed on the basis of the information that was known (or ought reasonably to have been known) to the utility at the time the decision was made, without the benefit hindsight.[152]

232. Applying these criteria, it is submitted that:

a. OPG is entitled to the presumption of prudence with respect to the provisions of the collective agreement entered into with the PWU in 2009. No evidence was adduced to rebut that presumption and, as a result, it is not necessary to undertake the second stage of the inquiry; and

b. In the event it is determined that the presumption of prudence has been rebutted, there is no contemporaneous evidence that the expenses in question are not prudent.

233. It is submitted that there is no evidence in this case which rebuts the presumption of prudence. In particular, it is submitted that evidence which simply compares OPG compensation rates with those of other, non-nuclear, industrial establishments is not evidence of a lack of prudence on the part of OPG.

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[150] (2005) 75 O.R. (3d) 72 (Ont. Div. Ct.)
[151] *supra,* at para. 9
[152] *Enbridge Gas Distribution v. Ontario Energy Board*, (2006) 210 O.A.C. 4 at para. 8-12 (C.A.)

234. It is submitted that a management decision can only be determined to be “not prudent” when it is demonstrated that there were other options reasonably available to management that they did not select. Moreover, it must be demonstrated that those options were more advantageous than the selected option, when viewed from the perspective of the contemporaneous evidence reasonably available to the decision-maker. There was no evidence adduced at the hearing to suggest any means or mechanism available to OPG to have achieved a collective agreement with the PWU in 2009 on more favourable terms than actually achieved.

235. In the event the Board is satisfied that the presumption of prudence has been rebutted, it is submitted that there is no basis for the Board to conclude, on the evidence adduced in this case, that OPG was not acting prudently when it concluded its current collective agreement with the PWU in 2009. Critically, in order to conclude that OPG has not been prudent, the Board must be satisfied that the expenses in question were, “dishonestly incurred, or which are negligent or wasteful losses…”. There was no suggestion, and certainly no evidence whatsoever that the compensation rates for PWU represented staff as contained in the collective agreement entered into in 2009 meet this standard.

236. As noted above, a management decision can only be determined to be “not prudent” when it is demonstrated that there were other, more favourable options reasonably available to management that they did not select. The evidence at the hearing was that, there are two mechanisms available as an alternative to a negotiated settlement of a collective agreement. The first is consensual binding arbitration. The second is a work stoppage, followed either by a negotiated agreement, or by consensual or imposed binding arbitration.

237. With respect to the first alternative, there was no evidence adduced that consensual binding arbitration was likely to have resulted in a lower cost outcome than was actually achieved through negotiation.

238. Indeed, arbitration settlements are determined largely by reference to the escalation contained in external comparator settlements. In comparing OPG wages, OPG draws on information gathered by Towers Perrin for comparator organizations.

These comparator organizations represent a cross-section of Canadian utilities including some very large corporations.[153] Consistent with OPG's approach of using Canadian utilities as the external comparators, a comparison of average wage increases for Canadian utilities in 2009 reported in the Human Resources and Skill Development Canada on Major Wage Settlements by year for the utility sector at 3%[154] is similar to that contained in the OPG-PWU collective agreement.

239. A similar analysis is applicable to OPG's forecast with respect to PWU compensation rates for the balance of the test period, after March 2012, as well as with respect to Society compensation rates after December 2010, given that they are also subject to collective bargaining. It is submitted that OPG's forecast of the escalation of labour rates arising from the collective agreements to commence in 2011 and 2012 are consistent with wage increases in the power sector and more generally in the economy as reflected in settlements and interest arbitration awards.

240. With respect to the work stoppage alternative, there was no evidence that a settlement or arbitration achieved after a work stoppage is likely to be more favourable to the employer than a negotiated agreement made without a work stoppage. Indeed, it is just as likely that an outcome achieved after a work stoppage could be less favourable to the employer than one made without a work stoppage. Logically, the outcome will be governed by a large variety of factors, not least the bargaining power of the respective parties. In that regard, it is relevant that, in OPG's view, it is unlikely that it would be able to continue nuclear operations in the face of a PWU work stoppage.[155]

241. Leaving aside the question of collective bargaining outcomes, it is also relevant when assessing what is reasonable and prudent compensation to consider the price paid by consumers to obtain the various alternatives. In particular, as noted above, there was evidence that a PWU work stoppage would likely lead to the cessation of OPG's nuclear operations. It is clear that event would have a very significant negative

[153] EB-2010-2008, Transcript Volume 8, Page 163, Line 25 to Page 164, Line 2.
[154] http://www.hrsdc.gc.ca/eng/labour/labour_relations/info_analysis/wages/settlements/2010/06/yearly.shtml#a3
[155] EB-2010-0008, Transcript Volume 9, Page 36, Lines 23-26.

impact on OPG's financial situation,[156] and on the cost and security of electricity supply to Ontario businesses and residents. It is submitted that these are real costs that must be assessed in considering whether pursuing a work stoppage is a reasonable and prudent alternative to a negotiated settlement. These potential outcomes are also relevant to the Board's obligation to be guided by its other statutory objectives, in particular, the objective of "protect[ing] the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service."[157]

242. In addition, there is no reason to believe that the provisions of the *Public Sector Wage Restraint Act* (the "*Act*") will have any effect on the terms of the renewal of the collective agreement between OPG and the PWU in 2012, and between OPG and the Society in 2010. First, the provisions of the *Act* expressly exclude employees governed by collective agreements. Second, a series of arbitration awards have confirmed that in cases governed by binding arbitration, arbitrators are in no way constrained by the provisions of the *Act* in determining compensation.[158]

243. In this environment, there is no basis upon which the Board can conclude that a decrease in PWU and Society compensation (or even an increase in PWU and Society compensation at a rate lower than forecast by OPG) is an achievable result in 2012 and 2010 respectively. In the absence of any evidence to suggest that another result is reasonably achievable, the Board has no basis to conclude that OPG's forecast of PWU and Society compensation costs is not reasonable and prudent.

244. Benefits, like wages are also an outcome of collective bargaining.[159] It is part of a collective agreement reached through negotiations based on mutual interests and areas of trade off between the parties[160] and as submitted above, there is no evidence deduced in this proceeding that rebuts the presumption of prudence with regard to the existing collective agreements. Evidence on the cost of specific benefits covered by the collective agreement is not evidence of a lack of prudence on the part of OPG.

[156] EB-2010-0008, J9.4, Page 1, Lines 20-21. "Using these assumptions, the financial impact to OPG of a PWU work stoppage during the 2011-2012 would be a loss of approximately $5.2M/day."
[157] *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch. B, s.1
[158] EB-2010-0008, Exhibit K9.1 and Exhibit K9.2.
[159] EB-2010-2008, Exhibit F4, Tab 3, Schedule 1, Page 5, Line 31 to Page 6, Line 1.
[160] EB-2010-2008, Exhibit L, Tab 11, Schedule 22, Page 2, Lines 6-9.

b. Consideration of Compensation, Productivity and Skill Levels

245. OPG's goal is to pay market rates for labour:

> **I would like to start just with a general statement regarding OPG's philosophy with regard to staff compensation, or a question about your philosophy.**
>
> **And would it be accurate to say that with regard to the compensation OPG pays its employees, would you accept that OPG should be paying market rates for labour?**
>
> **MS. IRVINE: That would be our goal, yes.** [161]

246. In line with this objective, OPG monitors compensation levels in the industry to help calibrate expectations and allow it to contain wage increases while continuing to attract highly skilled staff.[162] In doing so, OPG uses a comparison to the 75th percentile based on data provided in a study prepared by Towers Perrin "because of the relative complexity of work in a large, regulated and nuclear environment."[163]

247. Should the Board be swayed to further consider the reasonableness of OPG's compensation levels despite the realities of the collective bargaining framework submitted above, it would be imperative for the Board to take note of the fact that one of OPG's cost containment initiatives negotiated with the PWU is skill broadening.[164] Skill broadening increases productivity by providing OPG with the ability to use one employee with multiple skills to do a job instead of requiring multiple employees with single skills to do the same job. OPG initiated skill broadening through collective bargaining with the PWU to address maintenance backlogs and increase the amount of work that one employee could do. This initiative is an illustration of how collective bargaining can and has reduced total compensation costs and incorporated greater workforce flexibility at OPG. As noted by OPG's witness, skill broadening is not an initiative that has been undertaken by too many unionized employers:

> **MS. IRVINE: There are not too many unionized employers that have broken down the job family silos that traditionally exist in skilled trades. ...**
>
> **So now we have the ability, within the collective agreement, to ask a mechanic to learn rudimentary electrician skills, so that instead of sending out a mechanic and**

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[161] EB-2010-0008, Transcript Volume 8, Page 149, Lines 5-11.
[162] EB-2010-0008, Exhibit L, Tab 11, Schedule 22, Page 2, Lines 25-27.
[163] EB-2010-0008, Exhibit L, Tab 1, Schedule 81, Page 1, Lines 39-41.
[164] EB-2010-0008, Exhibit F4, Tab 3, Schedule 1, Page 15, Lines 19-24.

an electrician to say fix a pump, one being to disconnect the motor, the other being to fix the pump, we could send out one employee.

So we do know that those kinds of things are not traditionally found in unionized workplaces, that we have cut some ground there.

MS. CHAPLIN: And what was it that led you to make that change?

MS. IRVINE: It was we wanted to increase productivity. ... [165]

248. Another factor that the Board must consider in reviewing compensation levels is skill level:

MS. IRVINE: Well, generally, we find that within the nuclear environment, work is very prescribed and proceduralized, and it is a series of quite complicated knowledge streams that you would need to know in order to follow the procedure appropriately when you are doing work.

And so we believe that those kinds of requirements are not necessarily found in many other non-nuclear workplaces.

...

MS. CHAPLIN: Okay. So it is related to the skill level. ...[166]

249. OPG's application states "that while some positions are paid above market and some are below market, OPG is slightly above the 75th percentile of market on an overall basis."[167] Given the evidence on the skill broadening initiative and skill levels presented above, the PWU submits that it is imperative when reviewing the outcome of the benchmarking exercise, that the Board recognizes the futility of assessing compensation cost in isolation of an assessment of productivity and skill level. The PWU submits that the Board's failure to do so will reduce the incentive for OPG to pursue efficiency initiatives.

250. The PWU submits there is no valid basis for the Board to disallow compensation costs to the extent that the costs would be reflective of compensation levels at particular percentiles. Doing so would be reminiscent of the Board disallowance in the Hydro One Case that Board Staff referenced in cross examination.[168] The PWU submits that the Board's cost disallowance in that proceeding was based on flawed analysis that

[165] EB-2010-0008, Transcript Volume 9, Page 124, Line 19 to Page 125, Line 9.
[166] EB-2010-0008, Transcript Volume 9, Page 124, Line 10 to Page 125, Line 9.
[167] EB-2010-0008, Exhibit F4, Tab 3, Schedule 1, Page 30, Lines 9-11.
[168] EB-2010-0008, Transcript Volume 8, Page 156, Lines 11-16.

considered compensation benchmarking in isolation of any meaningful assessment of relative productivity.[169]

251. The productivity issue aside, should the Board be persuaded to persist on the issue of comparators, it must consider that the vast majority of OPG's employees work in the nuclear area.[170] For these employees, it is clear that OPG's only relevant comparator is Bruce Power:

a. It is the only other nuclear generator in Ontario and in terms of the nature of the jobs and the nature of the skills that are required, it s a very close comparator;

b. There is a traceable common origin to the OPG's and Bruce Power's businesses and the compensation rates;

c. OPG and Bruce Power face common challenges with respect to demographics and recruitment;

d. Bruce Power is an unregulated, private sector operator and is a "market test" for OPG; and

e. With respect to the unionized employees, there is common representation (i.e. the PWU and the Society) for both OPG and Bruce Power.

252. At least with regard to the PWU represented employee classifications Bruce Power pays consistently and materially more than OPG. In 2009 OPG's wages for PWU represented employees were 10 per cent lower than Bruce Power's wages on a weighted average basis.[171] For Society represented employees the pay ranges for OPG and Bruce Power were similar.[172]

253. The PWU's concern with regard to compensation levels in this proceeding is not with the direct reduction of compensation levels, as they are determined in a process totally external to the Board's jurisdiction (i.e. binding legal collective agreements that

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[169] EB-2010-0002, PWU Final Argument, Paragraphs 52 to 63.
[170] EB-2010-0008, Undertaking J9.6, Page 3.
[171] EB-2010-0008, Exhibit F4, Tab 3, Schedule 1, Page 32, Chart 12 and Lines 11-12.
[172] EB-2010-0008, Exhibit F4, Tab 3, Schedule 1, Chart 13 and Lines 2-3.

govern the terms condition of employment[173]). Rather, the concern is that any such disallowance of compensation costs will be based on:

a. a complete absence of evidence that compensation costs are not reasonable and prudent as defined by the Court of Appeal;

b. a complete absence of evidence that OPG had an advantageous alternative to a negotiated settlement that was not pursued; or

c. inadequate consideration of the reasonableness of the compensation levels (i.e. comparison of compensation costs in isolation of productivity and skill levels).

254. Critically, any such disallowance will result in the deferral of work programs that have been prioritized in the business planning process "to maximize value, while considering risks and OPG's business objectives as well as alignment with business unit strategies and facility Life Cycle Plans (as applicable)".[174] Deferral of these work programs therefore, will be at higher cost in the future resulting in unfair intergenerational subsidy.

255. Therefore, given the fact that the results of the collective bargaining process and the collective agreement will not be affected by Board determinations, should the Board find reason to disallow compensation costs, it is imperative that the Board specify how OPG is to allocate the cost disallowance and to provide the Board's understanding of what the consequence of that allocation might be.

256. Ultimately, in establishing rates, what matters in terms of compensation is total compensation cost. In that respect OPG's proposed total compensation for 2011 and 2012 at $1,381.7M and $1,402.2M respectively are lower than the total compensation levels for 2009 and 2010 of $1,439.3M and $1,422.7M.[175] Relative to the 2008 total compensation level of $1377.2M, the proposed 2011 level represents an increase over the three-year period of $4.5M (0.3%) while the proposed 2012 level represents an increase of $25M (1.8%) over the four-year period. Compared to 2007, the proposed

[173] EB-2010-0008, Exhibit L, Tab 11, Schedule 22, Page 1, Line 36.
[174] EB-2010-0008, Exhibit A2, Tab 2, Schedule 1, Attachment 1, Page 14, Paragraph 7.
[175] EB-2010-0008, Exhibit L, Tab 1, Schedule 74, Page 1.

2011 total compensation represents an increase of $29.4M (2.2%) while the proposed 2012 total compensation represents an increase of $49.8 (3.7%).

257. Compensation for the PWU and Society represented employees make up an overwhelming portion of the total compensation costs. Given the actual and forecast annual increases in PWU and Society compensation rates for the 2007-2012 period, the increase in total compensation cost between 2007 and 2012 at 3.7% illustrates the effectiveness of OPG's efficiency initiatives (e.g. skill broadening) and the need for the Board to avoid comparisons of compensation levels in isolation of efficiency considerations.

258. In conclusion, there is no evidence that the current PWU and Society compensation rates were not reasonable and prudent when the present collective agreements were entered into. Nor is there evidence that any escalation in compensation lower than forecast by OPG for the test years is reasonably achievable. Disallowance of compensation costs based on flawed comparisons of compensation levels are likely to result in the deferral of work programs that will cost more to undertake in the future and acerbate future rate impacts and intergenerational inequity. Further it discourages the pursuit of efficiency initiatives in the collective bargaining process. Therefore the PWU submits that the Board should approve OPG's compensation levels for the test years as proposed.

c. Board Staff's Submissions on Compensation

259. Board Staff addresses OPG compensation issues at pages 64 to 70 of its submissions. Board Staff proposes reduction to various aspect of compensation, the largest being a $37.7M reduction for each of the test years arising from an analysis of OPG's performance relative to a Towers Perrin survey.[176]

260. The Towers Perrin survey contained only a small number of job categories which were comparable to job categories at OPG. As noted by Board Staff, the comparable job categories encompassed only 28 per cent of the total incumbents in OPG's regulated businesses, virtually none of them identifiable nuclear positions. Nevertheless, in order to arrive at its recommendation, Board Staff extrapolates the

[176] EB-2010-0008, Board Staff submissions Page 66.

results of the Towers Perrin survey to the entire OPG regulated workforce. Board Staff justifies this exercise on the following basis:

> **Given that 28 of 30 OPG positions (or 93%) were above the 50th percentile, the results based on the 30 occupations *are likely representative of all of the union-represented jobs in OPG's regulated business.*** (emphasis added)[177]

261. The PWU submits that Board Staff's analysis and conclusion is fundamentally flawed. It in no way addresses any of the considerations set out in the above paragraphs. More directly, there is no basis in the evidence to extend the results of the comparison of the comparable positions to those where there are no comparables. Moreover, there is no basis in logic to do so. It is important to understand what Board Staff is actually suggesting. While acknowledging that the other employers in the survey do not actually have persons employed in positions which are comparable to those performed by over 70 per cent of OPG employees in the regulated business, the Board should assume that if these companies *did employ persons in these positions, then they would pay them less than OPG does.* The PWU submits that this is no basis upon which the Board can disallow costs to an applicant.

262. Board Staff's analysis also ignores (and is contradicted by) the evidence that the one directly comparable Ontario based business (Bruce Power) does employ people in all of the same kinds of nuclear jobs as OPG, and uniformly pays those employees *more than OPG does*.

G. DEFERRAL AND VARIANCE ACCOUNTS

Issue 10.3: Is the disposition methodology appropriate?

263. OPG has modified its proposal so as to clear the actual audited Deferral and Variance Account balances as of December 31, 2010 rather than the forecast balances. OPG submitted that the expected timing of the OEB's decision would allow OPG sufficient time to have its December 31, 2010 actual balances audited by OPG's external auditors. OPG expects that the auditors' report will be available in early

[177] EB-2010-0008, Board Staff submissions Page 66.

February 2011. Under OPG's proposal, the auditors' report and any proposed adjustments to the accounts resulting from the OEB's Decision would be available for intervenors and Board staff to review and comment on during the review process for the payment amounts order. OPG noted that the auditors' report would provide additional assurance to the OEB with respect to the accuracy of the balances. According to OPG, this approach and timing are consistent with the proposed effective date for new payment amounts of March 1, 2011.[178]

264. The PWU notes that OPG's proposal is analogous to the Board's approval of Deferral and Variance Account audited balances as at December 31, 2009 in the Hydro One Networks Inc, 2010-2011 Distribution Rate application.

> **While acknowledging that past Board decisions have at times varied on the disposition of audited or non-audited balances for deferral and variance accounts, in this case, the Board will order that only audited amounts will be cleared. Hydro One has indicated that audited values will be available for 2009 in time for the issuance of the rate order for this proceeding. Board approves the clearance of 2009 audited balances and directs Hydro One to prepare the draft rate order for Board's approval on that basis.**[179]

265. The PWU submits that OPG's proposal to clear actual audited balances as of December 31, 2010 is reasonable and should be approved by the Board.

H. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

Issue 12.1: When would it be appropriate for the Board to establish incentive regulation, or other form of alternative rate regulation, for setting payment amounts?

266. It would be appropriate for the Board to establish incentive regulation ("IR") or another form of alternative rate regulation when:

a. The base payment amounts provide a robust starting point for an IR formula;

b. Data required for the determination of the IR formula are available;

[178] EB-2010-0008, OPG Argument-in-Chief, Page 90, Lines 1-9.
[179] EB-2009-0096, Hydro One Networks Inc.'s 2010 and 2011 Distribution Rates, Decision with Reasons, April 9, 2010. Page 53.

c. The environment that OPG operates within is expected to be relatively stable for the term of the IR plan; and

d. A robust service quality regulation plan is available or can be developed to incorporate into the IR framework.

267. The base payment amounts that would provide a robust starting point for IR are those that reflect the work program portfolio for the duration of the IR plan. As an example, the size of rate base implicit in the determination of the base payment amounts is reflective of the size of rate base expected over the duration of the IR plan. That is, no significant additions or reductions in rate base are anticipated and no extraordinary maintenance projects or initiatives are required over the course of the IR plan.

268. In view of the plans for nuclear refurbishment discussed in the evidence in the present case and revealed in the Government's recently released Ontario LTEP, it appears that in the coming decade there are very likely to be extraordinary changes to OPG's rate base and work programs. In those circumstances, it is unlikely that there will be the stable environment required for the introduction of an IR framework for the foreseeable future.

269. The IR formula developed must realistically reflect the cost escalation pressure faced by OPG, and OPG's potential for efficiency gains. In addition, OPG must have all relevant information required to make these determinations.

270. The PWU submits that the implementation of an IR plan requires a stable environment for the term of the plan. As an example, a time when significant uncertainty related to extreme economic instability or fundamental changes in government policy that impacts the regulated entity is expected to prevail over the term of an IR plan, would not be an appropriate time to implement IR. This is because the impact of the economic instability and changes in policy on the regulated entities would not have been contemplated in the IR formula and can be expected to render the IR formula unrealistic and flawed.

271. If the alternative regulatory mechanism under consideration is IR, it will be key from the consumers' perspective, that robust service quality/reliability regulation is included in the IR framework to ensure that the IR mechanism does not result in cuts in O&M and capital investments that results in the deterioration of station assets and service reliability, and diminishes consumer value. In the case of OPG, lower value can mean lower production from these assets that would need to be replaced with higher priced supply.

Issue 12.2: What processes should be adopted to establish the framework for incentive regulation, or other form of alternative rate regulation, that would be applied in a future test period?

272. In its submission on the Issues List for this proceeding the PWU provided the Board with the input below on a process to be adopted to establish the framework for IR, or other form of alternative rate regulation, that would be applied in a future test period.

> **In the PWU's view a suitable process would start with a consultation process initiated either by OPG or by the Board to determine the future method for the regulation of OPG. A consultation process provides learning opportunity for stakeholders, Board staff and OPG through discussions and research on options, and the development of a common of the merits and shortcomings of the available options relative to a set of principles.**
>
> **As is frequently the case in the Board's consultation processes, the start point would be a Discussion Paper prepared by an expert consultant that sets out and reviews the options, and reviews IRMs and other forms of alternative regulation adopted for generators in other jurisdictions. The Discussion Paper should also provide input on the appropriateness of implementing an IR approach or other form of alternative regulation for OPG taking into account significant impacts of the environment within which OPG is currently operating. A technical conference could then help OPG and interested parties obtain a better understanding of the options and the impact of current environmental conditions on the implementation of the options. Interested parties should then be provided opportunity to comment on the appropriateness of the options as alternative regulatory approaches for OPG and the impact of current environmental conditions. These comments might be structured around a series of questions prepared by the party running the consultation (e.g. OPG or Board staff) to enhance the value of the input received in the consideration of IR or other form of alternative regulation for OPG.**
>
> **If the convener of the consultation process, following the review of stakeholders' input believes further investigations into IR options and other forms of alternative regulation and the impact of current environmental conditions is in order, a working group approach such as that used in the development of 3rd Generation IRM for the electricity distributors is well suited to these deliberations.**

A proceeding, initiated could then be held to review: an appropriate IR or alternative form of regulatory framework; when it would be appropriate for the Board to establish IR or other form of alternative rate regulation; and, to examine issues to establish appropriate base payment amounts as the starting point for an IR or other form of alternative rate regulation plan.[180]

273. In response to interrogatory L-1-150, OPG sets out a process to cover the appropriate structure for a future method of regulating OPG and how best to achieve that structure. The difference between the process described by the PWU and OPG stems from the difference in the initiation of the process. In the process put forth by the PWU, the process, or proceeding, is initiated by the Board on its own initiative with the release of a Board discussion paper, which would form the basis for the development of an IR plan. In the process put forth by OPG, the proceeding is initiated as a result of an OPG application to the Board for approval of an IR plan developed by OPG. When initiated in that way, the PWU views the process described by OPG to be appropriate. In particular, the PWU agrees with OPG that it is not appropriate to include a settlement conference in a proceeding designed to create a regulatory framework for adoption by the Board. In the PWU's view it is essential that the Board fully understands the incentives implicit in any regulatory framework that it adopts, and that the Board is confident that reliability will be maintained/improved. The proposed regulatory framework therefore should be fully tested before the Board, rather than being the product of a series of trade-offs brokered amongst a select group of stakeholders.

I. CONCLUSION

274. For all the above reasons, and considerations that call for the Board's appropriate judgement with respect to the individual components of the application, the PWU respectfully submits that OPG's proposed 2011 and 2012 payment amounts for its prescribed assets are reasonable and prudent, and therefore merits Board approval as proposed.

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180 http://www.rds.oeb.gov.on.ca/webdrawer/webdrawer.dll/webdrawer/rec/203922/view/PWU_sub_draft_issues_list_20100713.PDF

ALL OF WHICH IS RESPECTFULLY SUBMITTED