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December 13, 2016

RESS, COURIER & EMAIL

Ontario Energy Board
Suite 2700
2300 Yonge Street P.O. Box 2319
Toronto, Ontario M4P 1E4

Attention: Mrs. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: EB-2016-0152 – OPG 2017-2021 Payment Amounts
OPG Reply to Motions

We are legal counsel to Ontario Power Generation Inc. ("OPG") in the above noted proceeding.

On December 2, 2016, Environmental Defence ("ED"), Green Energy Coalition ("GEC") and School Energy Coalition ("SEC") each filed a notice of motion to compel further responses by OPG to certain interrogatories and/or undertakings.

Enclosed are OPG's reply submissions to the motions brought by ED and GEC. With respect to the one interrogatory covered by the SEC motion, OPG intends to file the information requested by December 22, 2016.

Yours truly,

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cc: Barb Reuber
Carlton Mathias
Violet Binnet
Intervenors

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. pursuant to section 78.1 of the Act for an order or orders approving payment amounts for prescribed generating facilities commencing January 1, 2017;

AND IN THE MATTER OF Rules 8 and 27 of the Board's *Rules of Practice and Procedure*.

OPG REPLY SUBMISSIONS TO MOTIONS

1. These are the submissions of Ontario Power Generation Inc. ("**OPG**") made in reply to the motions filed by Environmental Defence ("**ED**") and Green Energy Coalition ("**GEC**") on December 2, 2016 to compel further responses by OPG in respect of certain interrogatories and undertakings.[1]

2. On December 9 OEB staff filed a submission in support of the above motions. ED also filed a letter in support of one aspect of GEC's motion. These submissions are also addressed in OPG's reply.

3. For the reasons set out further below, it is OPG's position that the ED and GEC motions should be dismissed.

A. REPLY TO ED MOTION

Introduction

4. ED filed a motion to compel further answers to certain interrogatories and undertakings. This motion should be denied in its entirety. OPG has provided full and adequate

[1] School Energy Coalition ("**SEC**") also brought a motion on the same day. OPG will provide a response to the one interrogatory covered by the SEC motion.

responses to those interrogatories that are relevant and appropriately objected to those interrogatories seeking information that is not relevant to this proceeding. Where information had been requested from the IESO, the IESO has provided the information that underpins its assessments of Pickering Extended Operations ("**PEO**") as filed in evidence.[2]

5. At the heart of the ED motion is its claim that it is appropriate for the OEB to consider in reviewing this application the availability and cost of alternative generation sources that ED prefers to OPG's Pickering Nuclear Generating Station ("**Pickering**"). ED asserts that this information is necessary to support its argument that the OEB should set a ceiling on the cost of Pickering based on a "proxy market price" and establish nuclear payment amounts on this basis. OPG respectfully submits that, on its face this exercise has no relevance to OPG's application for just and reasonable payment amounts.

6. "Market proxy" is a concept of ED's own making and one that it never defines or provides any evidence to support. It also offers no basis for its legitimacy as a regulatory tool. ED argues that it is entitled in this proceeding to request information from OPG and the IESO that it believes is necessary to show that an alternative mix of resources would be cheaper than Pickering. The flaw in this argument is that no matter how much ED seeks to present its proposal in terms of cost, what it is ultimately asking the OEB to do is to determine that the Minister should have selected a resource mix that does not include Pickering operating beyond August 31, 2018 and set OPG's payment amounts on this basis. As discussed below, the OEB has correctly and repeatedly rejected similar requests in the past and should do so again.

7. The OEB has recognized that the selection of the types and quantities of generation to meet Ontario system need is a system planning exercise. By law, responsibility for system planning now rests with the Minister of Energy.[3] That the Minister of Energy has approved OPG's plan to extend Pickering's operation beyond 2020 cannot reasonably be disputed. The Ministry of Energy's website states:

[2] Ex. F2-2-3, Attachment 1.

[3] *Electricity Act, 1998*, Section 25.29 (see Compendium of Referenced Materials ("**Referenced Materials**") attached to these submissions, p. 1).

> "The Province has also approved OPG's plan to pursue continued operation of the Pickering Generating Station beyond 2020 up to 2024, which would protect 4,500 jobs across the Durham region, avoid 8 million tonnes of greenhouse gas emissions, and save Ontario electricity consumers up to $600 million."[4]

8. More recently, the Minister's consultation document on the 2017 Long-term Energy Plan ("**LTEP**") states: "Keeping Pickering running until 2024 will ensure the province has a reliable source of GHG-free baseload electricity to carry it through the refurbishment of the Darlington and the initial Bruce units."[5] While ED is free to disagree with the decision that Pickering should operate to 2022/24, the OEB should not allow OPG's payment amount application to be used as a forum to air this disagreement. Running economic assessments of alternative system plans of PEO under the conceptual guise of a "market proxy" would necessarily involve the OEB in the type of system planning and system need questions that, as shown below, the OEB has previously recognized are the purview of the Minister of Energy.

9. The multiple scenarios sought by the ED will not advance any understanding of what a "market proxy" is, its suitability for regulatory purposes and the basis on which it could be employed in setting rates. It will not, therefore, advance the OEB's thinking on the reasonableness of cost and the determination of payment amounts. As such, the information sought is not relevant to the proceeding.

10. Contrary to the submissions of OEB staff, OPG fully recognizes that the OEB has broad discretion to set payment amounts and accepts that OEB approval is necessary to recover the costs of PEO.[6] In this application, OPG is seeking approval of nuclear payment amounts that are based on five annual nuclear revenue requirements covering 2017-21. These revenue requirements include both funding for PEO and Pickering's normal

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[4] See: https://news.ontario.ca/mei/en/2016/01/ontario-moving-forward-with-nuclear-refurbishment-at-darlington-and-pursuing-continued-operations-at.html and the news release at Ex. L-6.5-1 Staff 114 and Staff 115 (see Referenced Materials, pp. 3-5).

[5] Government of Ontario, *Planning Ontario's Energy Future: A Discussion Guide to Start the Conversation*, p. 40 <http://www.energy.gov.on.ca/en/ltep/2017-discussion-guide/> (see Referenced Materials, p. 7).

[6] Contrary to OEB staff's suggestion, it is OEB's approval of the cost of PEO, rather than the approval of the need for Pickering to operate to 2022/24 that is being referenced in the Minister's announcement. See OEB Staff Submissions, p. 8.

operating costs.[7] By requesting approval of these amounts, OPG has explicitly recognized the OEB's authority to approve the requested costs and that the OEB is not bound to accept these costs. Where OEB staff's submissions appear to diverge from both OPG's position and the OEB's prior decisions is on the question of whether the use of costs of an alternative system plan, as requested by ED, is relevant to the requested approval of nuclear payment amounts. OPG respectfully submits that it is not.

11. Finally, ED's suggested approach of basing OPG's payment amounts on a proxy market price would conflict with O. Reg. 53/05 which prohibits establishing OPG's payment amounts based on contracting out and requires that OPG be allowed to recover the cost to increase Pickering's output, if prudently incurred.

12. The sections below address:

    (a) The core of ED's argument that an investigation into the costs and availability of alternative generation sources is relevant to the determination of OPG's payment amounts;

    (b) OEB staff's comments on the Minister's approval of extending Pickering's operation and what that approval should mean for the conduct of this proceeding; and

    (c) Each of the interrogatories and undertakings for which ED seeks to compel further responses and demonstrates that either the answer provided was fully responsive or OPG's objection to the question was appropriate.

OPG concludes by requesting that, based on the foregoing, ED's motion be denied in its entirety.

[7] Ex.L-6.5-5 CCC-32 and the evidentiary reference contained therein (see Referenced Materials, p. 8).

The Cost and Availability of Alternative Generation Sources Is Not Relevant to Any Issue in This Proceeding

13. ED has suggested that the Province should close Pickering.[8] Consistent with this goal, it is attempting to convert this proceeding from an Application to set OPG's payment amounts to a review of the system planning decisions made by the Minister of Energy. With respect, such a review is clearly not part of the proceeding. Prior OEB decisions in OPG payment amount proceedings consistently support this view.

14. ED's antipathy to Pickering is easily seen in the first paragraph of its Grounds for Motion.[9] There ED unfairly characterizes Pickering's cost and operating performance. Rather than fairly citing Pickering's total generation cost, the metric that the OEB has used to benchmark the overall cost of operating the plant, ED cites to non-fuel operating costs because that metric makes Pickering look worse.[10] Similarly, despite the facts that Pickering substantially improved its force loss rate in 2015 and that this improvement is reflected in OPG's test period production forecast, ED cites Pickering's 3-year rolling average forced loss for 2012-14, again because the numbers are worse. It is worth recalling that in the prior payment amounts application, ED similarly called for substantial cost disallowances based on Pickering's performance. The OEB disagreed, stating:

> "Both Environmental Defence and GEC have proposed significant reductions related to poor economic performance of the Pickering units. The Board does not agree with these submissions. The government's direction on the operation of Pickering is set out in the Long-Term Energy Plan."[11]

[8] "But if they want to get back to balance, maybe they should begin by closing the aging Picking [*sic*] Nuclear plant, instead of extending it past its planned lifetime – and putting people at risk if there's an accident." ED, *We Need More, Not Less, Green Energy*, September 27, 2016 <http://environmentaldefence.ca/2016/09/27/need-more-green-energy/> (see Referenced Materials, p. 10).

[9] ED Motion, para. 2.

[10] EB-2013-0321, Decision with Reasons, p. 42 (see Referenced Materials, p. 13).

[11] EB-2013-0321, Decision with Reasons, p. 46 (see Referenced Materials, p. 15).

15. In the OEB's very first payment amount proceeding for OPG (EB-2007-0905), the OEB addressed intervenor arguments that it should decide the viability of continuing to operate Pickering. In response the OEB said:

> "This aspect of the decision gives rise to two significant issues. The first is whether the Board has the jurisdiction to determine the viability of the Pickering stations. ... With respect to the first issue, the Board agrees with OPG that the Board's role in this application is to review the proposed costs of the prescribed facilities and to order reasonable payment amounts."[12]

16. In EB-2010-0008, the OEB first considered the issue of extending Pickering's operations. Again, despite intervenor requests that the OEB consider the need for Pickering, the OEB found that its role was limited to determining whether the planned spending on continued operations was reasonable and approved OPG's spending request.[13]

17. When faced with another invitation to expand the scope of the issue of extending Pickering's operations in EB-2013-0321, the OEB again declined, stating: "The Board agrees with OPG that generation planning is not within the scope of this proceeding."[14]

18. OEB staff's submissions suggest that the Minister's approval of PEO should be given less weight in this proceeding than the OEB has given the Minister's resource planning decisions in prior proceedings. With respect, this submission is based on an incorrect statement of the Minister's responsibilities for system planning and a factually inaccurate view of the evidence on the record of this proceeding concerning the Government's approval of PEO.

19. OEB staff's submission at page 6 states: "OEB staff recognizes that the OEB is not the system planner. Typically that role is performed by the IESO based on the government's Long-Term Energy Plan (LTEP)." The reference to the IESO as system planner is incorrect. In late 2015, the Government introduced Bill 135, which amended the *Electricity Act, 1998* to give the Minister, not the IESO, responsibility for system

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[12] EB-2007-0905, Decision with Reasons, p. 28 (see Referenced Materials, p. 19).

[13] EB-2010-0008, Decision with Reasons, pp. 51-52 (see Referenced Materials, pp. 21-22).

[14] EB-2013-0321, Decision on Issues List (June 4, 2014), p. 3 (see Referenced Materials, p. 25).

planning.[15] The IESO's role is to supply technical analyses in support of the Minister's planning efforts.[16] As discussed below, with respect to extending Pickering's operation, the IESO fulfilled this role and supplied the Minister with detailed analyses to support his approval.

20. In its submission, OEB staff cites the doctrine of "implied exclusion", arguing that the Government did not expressly reference the need to extend Pickering's operation in a regulation (as it had done for the DRP) and that absent such an explicit fettering of the OEB's jurisdiction, the OEB can properly assess the need for the project itself. With respect to the DRP, the Province's endorsement of that program was made prior to the enactment of Bill 135, and an express statement in regulation provided enhanced clarity. As noted in the paragraph below, the Minister has clearly made the system planning decision to approve OPG's plan to pursue PEO, which is a foundational assumption of the pending LTEP.

21. OEB staff claims that the Minister's decision to approve OPG's plan to operate Pickering to 2022/24 should not be given the same weight as the LTEP. This submission ignores the reality that not all system planning decisions can be "put on hold" during the four years between LTEPs. The Minister's decision to approve OPG's plan to pursue PEO exemplifies this circumstance because given the cost, timing and effort that would be required to end commercial operations at Pickering in 2020, waiting for completion of the 2017 LTEP to announce the extension was simply not a practical alternative. While OEB staff characterizes this decision as having been done through a press release, the fact is that the Minister's public announcement of his approval[17] followed more than a year of work by the IESO and Ministry of Energy staff as discussed in the next paragraph. Furthermore, as noted above in paragraph 8, the consultation document that the Minister has issued for the 2017 LTEP reiterates the Government's commitment to operating Pickering until 2024.

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[15] *Electricity Act, 1998*, Section 25.29(1) (see Referenced Materials, p. 1).

[16] *Electricity Act, 1998*, Section 25.29(3) (see Referenced Materials, p. 1).

[17] See Minister's quote at: https://news.ontario.ca/mei/en/2016/01/ontario-moving-forward-with-nuclear-refurbishment-at-darlington-and-pursuing-continued-operations-at.html (see Referenced Materials, pp. 3-5).

22. In August 2014, at the request of the Ministry of Energy, the IESO developed an initial presentation reviewing different options for Pickering shutdown dates.[18] In December 2014, again at the Ministry's request, the IESO began conducting a detailed assessment of various Pickering shutdown dates, including a 2018 shutdown. This effort ultimately led to the submission of an extensive presentation to the Ministry in March of 2015.[19] The IESO continued its analysis throughout 2015 and provided the Ministry with an updated presentation in October 2015 showing the benefits of extending Pickering's operation to 2022/24 relative to a 2020 shutdown date.[20] As these documents show, OEB staff's suggestion that the Minister's decision to endorse PEO was not based on a rigorous analysis is misplaced.[21]

23. With the IESO's permission, OPG filed both of the IESO's detailed assessments as an attachment to OPG's evidence to show the information provided to the Minister of Energy prior to his January 2016 announcement. OPG included this analysis with its evidence because the OEB relied in part on a similar OPA analysis in its EB-2013-0321 decision approving Pickering Continued Operations and in the in EB-2010-0008 Decision had recommended that OPG file an independent OPA assessment in future proceedings.[22]

24. Like the analysis OPG undertook as part of the PEO business plan,[23] the IESO's analysis shows net benefits from extending Pickering's operation, albeit at a lower level. To the extent that OEB staff and intervenors have asked questions about the IESO's analysis, OPG directed these questions to the IESO and the IESO answered them fully based on available information.

25. What the IESO has not done is perform additional analyses beyond those provided to the Ministry of Energy. The two assessments filed were prepared as part of the Minister's decision making process prior to approving OPG's plan to pursue PEO rather than to

[18] Ex. L-6.5-7 ED-42, Attachment 1.

[19] Ex, F2-2-3, Attachment 1, pp. 24-116.

[20] Ex, F2-2-3, Attachment 1, pp. 1-23.

[21] OEB Staff Submissions, pp. 7-8.

[22] EB-2013-0321, Decision with Reasons, p. 51 (see Referenced Materials, p. 17); EB-2010-0008, Decision with Reasons, p. 52 (see Referenced Materials, p. 22).

[23] Ex. F2-2-3, Attachment 2.

support OPG's payment amounts application. OPG's inclusion of the IESO assessments with the evidence does not convert this proceeding from an Application to determine OPG's payment amounts to an opportunity to revisit the Minister's decision or to develop alternative system plans. This proceeding remains an application to set payment amounts for OPG; it is not a forum to change the Minister's system planning decisions.

26. ED says that the information it seeks on the cost and availability of generation alternatives is necessary to establish that there are cheaper alternatives to Pickering, which should be used as a "market proxy" to serve as a ceiling on Pickering's cost. With respect, even if this argument were true, it is irrelevant. The Minister determines the appropriate mix of resources to meet Ontario's electricity needs "balancing the Government of Ontario's goals and objectives respecting energy."[24] The cost, operating characteristics and environmental attributes of the individual resources that have been approved to comprise this mix, in the 2013 LTEP and in subsequent decisions, vary tremendously. The mix includes solar resources that cost substantially more than Pickering and hydroelectric resources that cost less. As such, it is not necessarily a "least cost plan". Rather, the mix represents the Minister's balancing of the Province's goals and objectives for energy. Without offering any evidence, ED appears to believe that it should be allowed to use discovery in this proceeding to compel the IESO to analyze the resources ED prefers to Pickering, so it can deem them a "market proxy" for Pickering and argue that they should serve as a ceiling on the cost of extending Pickering's operation.[25]

27. In effect, ED is arguing that the Minister selected the wrong resource mix and that the OEB should "fix" this by deeming Pickering to cost the same as a hypothetical purchase from Quebec in combination with an undefined mix of other alternative resources that ED designates least cost.[26] Such a course of action would be both inappropriate given the Minister's responsibility for system planning and inconsistent with the issue before the

[24] *Electricity Act, 1998*, Section 25.29(1) (see Referenced Materials, p. 1).

[25] ED has provided no evidence, beyond reference to a newspaper article, about the cost of its preferred resource, additional imports from Quebec. In contrast, as discussed in footnote 39 below, the IESO has provided a detailed interrogatory response (Ex. L-6.5-7 ED-40) showing that imports from Quebec are not a cost-effective or even viable replacement for Pickering.

[26] ED Motion, para. 9.

OEB in this proceeding – the determination of whether the costs that OPG is seeking to extend Pickering operations are appropriately part of just and reasonable payment amounts.

28. In law, to be relevant a fact must advance the OEB's thinking or consideration of an issue. The IESO's assessment produces a numerical result as to the benefit and comparative value of the expenditure of incremental costs for PEO. The multiple scenarios that ED seeks will do no more than produce another set of numerical results that show the costs of the resource mix ED prefers. This will not advance the OEB's efforts to determine the reasonable costs of Pickering or even assist in determining what a "market proxy" might be, let alone, its suitability as a basis on which to set payment amounts. Moreover, to advance the OEB's thinking on these rate making issues, the OEB would require evidence. There is none on the concept of "market proxy" because ED chose not to file evidence when given the opportunity to do so. In effect, the ill-defined concept of "market proxy" is nothing more than a vehicle to enable ED to do indirectly what the current energy planning regime will not permit it to do directly.

29. ED's "market proxy" approach also conflicts with the provisions of O. Reg. 53/05 which states: "In setting payment amounts for the assets prescribed under section 2, the OEB shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets."[27] The essence of ED's "market proxy" is that the costs of resources other than Pickering will be used to set the portion of OPG's payment amounts attributable to Pickering. Under the current planning regime, resources other than OPG's prescribed facilities are procured by the IESO through procurement contracts as contemplated under the *Electricity Act, 1998*. In substance, ED's "market proxy" is no different than saying Pickering's output will be contracted out on a proxy basis via the IESO at the price that ED believes Ontario should pay.

30. The costs to extend Pickering's operations, as opposed to its normal operating costs, are costs "incurred to increase the output of, refurbish or add operating capacity to a

[27] O. Reg. 53/05, section 6 (2) 2 (see Referenced Materials, p. 30).

generation facility" under O. Reg. 53/05, Section 6(2) para. 4. To the extent that the OEB determines these cost were prudently incurred, it must authorize their recovery.[28] It is virtually impossible to see how development of alternative resource scenarios as ED requests could be relevant to the discharge of the OEB's regulatory responsibilities under this section.

ED's Criticisms of the IESO Assessment Are Without Merit

31. ED argues that the IESO assessment is flawed because conditions have changed since it was undertaken.[29] OPG has two responses. The first is that the original and updated assessments included with OPG's evidence comprise the analysis that the IESO provided to the Ministry of Energy prior to the Minister's decision to endorse PEO. This is the information the Minister had available in deciding whether to approve OPG's plan. The second is that conditions are always changing. ED's interrogatory #30 cites the changes that it believes have made Pickering less economic and not those, such as carbon pricing, that go the other way.[30]

32. ED repeatedly claims that August 31, 2018 is the appropriate date to assess PEO because that is the date by which the Clarington Transformer Station is assumed to be in service. It claims that the IESO's assessment is incorrect because it does not use 2018 as the base case. Here again, ED's view is contrary to the decisions of the Minister of Energy, at odds with decisions by the OEB and CNSC, and inconsistent with the analysis the IESO actually performed.

(a) The Minister initially endorsed Pickering's operation until 2020 in approving the 2013 LTEP and subsequently has approved OPG's plan to operate the station to 2022/24.

[28] O. Reg. 53/05, section 6 (2) 4(ii) (see Referenced Materials, p. 30).
[29] ED Motion, paras. 6-7.
[30] ED Motion, paras. 18-19.

(b) The OEB in approving funding for Pickering Continued Operations in EB-2013-0321 authorized funding for the Fuel Channel Life Extension project, which was undertaken to enable Pickering to operate until the end of 2020.[31]

(c) The CNSC has approved Pickering's operating to 247,000 effective full power hours ("**EFPH**"), which allows the station to operate into 2020 and OPG is highly confident of continued safe operation of all Pickering Units to December 2020 based on fuel channel condition and interactions with CNSC staff.[32]

(d) The IESO's analysis is based on the Clarington Transformer Station coming into service in 2018 and shows the benefits of extending Pickering operations to 2022/24 assuming that Clarington Transformer Station is operating after 2018.[33] Moreover, one of the scenarios that the IESO considered in its March 2015 assessment was based on a 2018 closure, but it abandoned that date in favour of 2020 when it performed its updated assessment.[34]

In short, all of the decision above demonstrate that the appropriate base case for an assessment of extending Pickering's operation is 2020, not 2018 as ED suggests.

OPG Has Fully Responded to All Relevant Interrogatories and Undertakings

33. Below OPG discusses each of the interrogatories and undertakings listed in ED's Motion, in the order presented there, and refutes ED's claims that the answer provided or the objection offered is inappropriate.

Ex. L-6.5-7 ED-39

34. ED sought to have the IESO compare the cost of Pickering with a 2022/24 shut down date (as proposed by OPG) to: 1) an August 2018 shutdown date (as proposed by ED) with replacement power from Quebec; and 2) a December 2020 shut down date with

[31] EB-2013-0321, Decision with Reasons, pp. 50-51 (see Referenced Materials, pp. 16-17).

[32] Ex. F4-1-1, Attachment 1, p. 3; Ex. L-6.1-1 Staff 93(c) (see Referenced Materials, p. 32); Ex. L-6.5-1 Staff 123(a) (see Referenced Materials, pp. 33-34); and Undertaking JT1.17, Attachment M (see Referenced Materials, p. 37).

[33] Ex. L-6.5-1 Staff 134 (see Referenced Materials, p. 38).

[34] Ex. L-6.5-7 ED-033 (see Referenced Materials, p. 40).

replacement power from Quebec. The IESO responded that the alternative of procuring replacement capacity from Quebec was not feasible and that its analysis compared Pickering to the least cost option.

35. ED's motion states that "OPG declined to provide a response" to this interrogatory.[35] With respect, that is incorrect. This was an interrogatory that ED asked be directed to the IESO. OPG did so, and the IESO responded. That ED does not like the response provided does not mean that OPG failed to respond.

36. ED apparently was dissatisfied with this answer and at the Technical Conference sought to change its request so that the IESO would consider "a combination of lowest cost sources including increased power imports."[36] OPG properly objected to this additional request. The IESO had already indicated that it compared Pickering to what it determined was the least cost alternative. OPG objected based on its view, discussed above, that further analysis of other potential alternatives that ED might prefer would involve a system planning exercise not relevant to the issues properly within the scope of this application.

Ex. L-6.5-7 ED-35

37. Part a) of this interrogatory asked for the IESO's contingency plans should the CNSC require Pickering to cease operation on August 31, 2018. As noted above, this is not a realistic scenario given that the CNSC has already approved operation to 247,000 EFPH, which would take Pickering into 2020. Moreover, the CNSC decision on OPG's next operating licence is expected by August 31, 2018, making a closure decision effective that day extremely unlikely.

38. Nevertheless the IESO responded to this interrogatory by indicating: "The IESO is in the process of risk management planning for a variety of future risks as described in the Ontario Planning Outlook – costs and other attributes of options will be better defined as the planning further progresses." ED was dissatisfied with this answer and at the

[35] ED Motion, para. 10.
[36] Undertaking JT1.17, Attachment P (see Referenced Materials, p. 41).

Technical Conference requested that the IESO provide “its best possible answers to our questions now.”[37] ED’s intervention in this proceeding does not authorize it to set the IESO’s work plan or establish deadlines by which the IESO must complete certain system analyses.

39. Part b) of this interrogatory is in the same vein, but included a specific list of resources that the IESO should consider as alternatives to Pickering post-2018. Again the IESO was unable to provide the requested assessment, stating that: “The IESO’s consideration of options for addressing Ontario’s electricity requirements absent Pickering extended operation is still ongoing, the analysis would depend on the conditions laid out by the CNSC in its decision. The IESO would revisit its analysis at that time.”

40. This answer apparently did not satisfy ED and so it requested an additional response at the Technical Conference. OPG objected because the IESO had already responded to the question and requiring the IESO to develop the requested information would involve exactly the type of alternative system planning exercise that is not relevant to the issues before the OEB in this proceeding for the reasons given above.

Ex. L-6.5-7 ED-30

41. This interrogatory asks that the IESO redo its analysis of the net benefits of operating Pickering to 2022/24 using updated assumptions for seven parameters selected by ED and using ED’s preferred formulation of the natural gas price forecast (“substitute the NYMEX natural gas futures prices at Henry Hub for the IESO’s best estimate of the natural gas prices at Henry Hub.”). The IESO responded by referring ED to the recently released Ontario Planning Outlook, which shows the IESO’s current projections for long-term electricity demand and supply, and indicating that it had not updated its analysis of the benefits of PEO.

42. When ED renewed its request at the Technical Conference, OPG properly objected.[38] OPG had filed both the original and updated analyses that were provided to the Minister

[37] Undertaking JT1.17, Attachment N (see Referenced Materials, p. 42).
[38] Undertaking JT1.17, Attachment L (see Referenced Materials, p. 43).

prior to his decision to endorse OPG's plan to extend Pickering Operations. These analyses represented months of work and the IESO had indicated that no further analysis had been done. Thus, there was nothing more to provide.

43. ED points to a number of factors that it believes necessitate an updated analysis because they allegedly would show that extending Pickering operations is less beneficial than indicated in the IESO's analyses in evidence. As a factual matter many of ED's claims are wrong, most prominently that Quebec imports are a viable substitute for PEO,[39] but in any event these claims are irrelevant. They do not go to the issues properly before the OEB in this proceeding. OPG respectfully submits that there is no basis for requiring the IESO to update its analysis because such additional analysis is not relevant to this proceeding.

Undertaking JT2.5

44. As captured in the Transcript, this undertaking asked that: "OF THE COSTS INCLUDED IN ED 18, BOARD STAFF 116, AND GEC 38, TO ADVISE WHICH WERE INCLUDED OR EXCLUDED FROM THE ECONOMIC ASSESSMENT OF PICKERING, INCLUDING THE CALCULATION OF THE 6.5 CENTS PER KILOWATT-HOUR."[40] OPG has provided a detailed response to this undertaking, which begins by explaining what a LUEC calculation (the reference to "6.5 CENTS PER KILOWATT-HOUR" in the undertaking) is intended to capture and how it is calculated, and provides references to other undertakings and interrogatories that contain additional information on this subject. The answer then goes on to detail how the costs in the

[39] The IESO's response to Ex. L 6.5-7 ED-40 (see Referenced Materials, pp. 44-45) details the Ontario transmission upgrades that would be required to reliably import the requisite quantity of energy from Quebec and concludes: "To complete all necessary upgrades the total cost is in excess of $2 billion with an estimated seven to ten years lead time." It then goes on to say:

> [A]ny deal to supply baseload energy year round, similar to Ontario's nuclear plants, would require the construction of new generation in Quebec. This new generation would be more expensive than existing power because it would factor in the cost associated with new generation and transmission build, resulting in higher import prices for Ontario.

[40] This request was a follow-up to Undertaking JT2.4, which asked OPG "TO RECONCILE ED 18, BOARD STAFF 116, AND GEC 38, AND ADVISE THE DIFFERENCES WHAT COSTS WERE INCLUDED OR EXCLUDED AS BETWEEN THE THREE." As OPG explains in the initial paragraph of that response: "The numbers used in the three referenced documents are different because they were produced to respond to specific questions from the requesting parties. However, they are consistent and are reconciled below." (see Referenced Materials, p. 46).

referenced interrogatories differ from the costs that were included in the economic assessment and provides an example.

45. The nub of ED's complaint appears to be it does not like the way the economic assessment was done. As OPG explains in the undertaking response: "As described in the Pickering Extended Operations Economic Assessment, the financial evaluation and the related LUEC are calculated using **incremental** operating costs relative to a 2020 Pickering shutdown." (emphasis added) ED's complaint that the incremental OM&A costs used in the assessment differ from the fully allocated OM&A costs provided in response to Ex. L-6.5-1 Staff-116 is in effect ED disagreeing with the LUEC methodology, rather than with any failure of OPG to fully respond to the undertaking.

46. ED also complains that the information provided was not produced in tabular form as ED's counsel subsequently requested after the undertaking was recorded. OPG did not produce a table, because the detailed response OPG provided could not be reduced to a table. However, all of the information requested in the undertaking has been provided.

47. ED is also incorrect in its claim that OPG failed to fully justify why certain costs were properly excluded from OPG analysis.[41] In its response, OPG lists the costs that are either "non-incremental" or "non-cash" items and were excluded for these reasons.

Ex. L-6.5-7 ED-27

48. Part a) of this interrogatory requests the electronic "spreadsheets" underlying OPG's economic assessment presented in the PEO Business Case[42]. In Attachment 1 to the interrogatory response, OPG provided ED with all of the data used in the Economic Assessment. OPG did not provide the requested "spreadsheet" because the Economic Assessment is not based on a spreadsheet. Rather it depends on a complex model of Ontario production, imports and exports that uses OPG proprietary data and logic, contains thousands of lines of code and cannot be operated without substantial training and an appropriate software licence.

[41] ED Motion, para. 22.
[42] Ex. F2-2-3, Attachment 2, pp. 16-18 (see Referenced Materials, pp. 27-29).

49. OPG is willing to develop a spreadsheet that will allow ED to modify assumptions about Pickering costs. This spreadsheet would incorporate output from OPG's proprietary production model, but would be hardcoded data and as such, it would not allow ED to run alternative resource scenarios. It will, however, allow ED to modify assumptions about the costs of the project. OPG would undertake to produce this spreadsheet by December 22, 2016.

Ex. L-6.5-7 ED-28

50. Referencing the IESO's assessment (Exhibit F2-2-3, Attachment 1), ED sought Pickering's available capacity at the time of Ontario's peak annual demand. Contrary to the claim in ED's motion that the data for 2020-2024 was not provided, the IESO provided the requested information for 2020-2024 in its response to part b) of this interrogatory. That table is reproduced below with the 2020-2024 information highlighted:

	Case with +65 TWh of Pickering Production, Pickering to 2020	Case with +65 TWh of Pickering Production, Pickering to 2022/2024	Case with +62 TWh of Pickering Production, Pickering to 2020	Case with +62 TWh of Pickering Production, Pickering to 2022/2024
2015	2579	2579	2579	2579
2016	2578	2578	2578	2578
2017	2579	2063	2063	1547
2018	2064	2063	2064	2063
2019	2579	2063	2064	2063
2020	3094	3094	3094	2579
2021	0	3094	0	3094
2022	0	3094	0	3094
2023	0	2064	0	2064
2024	0	2064	0	2064

51. Furthermore, ED sought clarification of part b) of this interrogatory response in Undertaking JT1.17, Attachment G where ED inquired why available capacity in 2020 equals installed capacity and why an assumption of zero forced outage was used.[43] The IESO provided an answer, explaining "The Pickering capacity that is available at the time of peak demand is assumed to be the installed capacity, provided that it is not on planned outage or forced outage or in a derated state. The forced outage rate is accounted for within the reserve margin as well as in power system production simulation analysis." ED was given a full opportunity to ask questions at the Technical Conference.

[43] Undertaking JT1.17, Attachment G (see Referenced Materials, p. 49).

Notwithstanding that the question it posed has been fully answered, it now wants to pursue new questions through its motion.

Ex. L-6.5-7 ED-29

52. This interrogatory asks the IESO to provide and justify its "best current estimate" of the input assumptions for its analysis of PEO. ED wrongly claims the IESO's answers to this interrogatory are inadequate. The IESO submitted a five page interrogatory response covering ED's entire multi-part request, except for part e), which sought information from OPG that OPG provided. In Undertaking JT1.17, Attachment H, the IESO submitted an additional four pages of material responding to ED's request for clarification of the interrogatory response.[44] While ED's discussion of this interrogatory details its dissatisfaction with the substance of the IESO's responses, it fails to demonstrate that these answers are non-responsive or in any way incomplete. The fact that ED would prefer different answers to the answers provided does not mean that they are inadequate.

Ex. L-6.5-7 ED-33

53. ED submitted a nine-part interrogatory asking the IESO for information on surplus baseload generation and curtailed generation from water, wind and solar relative to Pickering closing on August 31, 2018. The IESO responded as follows:

> The scope of the IESO's assessment of Pickering extended operations referred to in Exhibit F2-2-3, Attachment 1, Page 6 of 116 (the "October 2015 study") was with respect to Pickering retirement at the end of 2020 versus extended operations to 2022/2024. The IESO did not evaluate extended operations relative to shutting Pickering down on August 31, 2018 in the October 2015 study. However, the March 2015 study included an assessment of surplus energy and net benefit relative to Pickering shutdown in 2018. This is illustrated in pages 42 through 116 of Exhibit F2-2-3 Attachment 1. Specifically, surplus energy is illustrated on page 53. Net benefit relative to shutting down in 2018 is summarized on page 61.

[44] Undertaking JT1.17, Attachment H (see Referenced Materials, pp. 54-57).

54. ED's motion claims that OPG declined to answer this interrogatory on the basis of relevance.[45] As shown in the preceding paragraph, that is simply not true; the IESO answered ED's interrogatory based on the information that it had. In addition, the IESO had already provided the corresponding information that it had developed relative to the 2020 closure base case in its responses to Ex. L-6.5-7 ED-31 and ED-32.

55. In Undertaking JT1.17, Attachment M, ED stated that no response had been provided to ED-33 and requested a response stating:

> August 31, 2018 is a highly relevant date for comparison purposes. Pickering cannot be shut down before that date, which is when the Clarington Transformer Station will be built. But after that date, Pickering is just one of a number of options to meet Ontario's electricity supply. At that point, OPG should not be paid more for the power from Pickering than the cheapest alternative, which could be considered to be the "market rate." After that date it is important to know what the lowest cost alternative is. Environmental Defence would argue that OPG should not be paid any more than the lowest cost alternative.

56. OPG did object to this further request because, on its face, it requires a discussion of "options to meet Ontario's electricity supply" that, as discussed above, are at the very heart of the system planning and system need issues that are not properly considered in this proceeding.

Undertaking JT1.17 G (re: ED Interrogatory #28)

57. This undertaking is a supplemental request for information on ED 28. Both the interrogatory and the supplemental request are addressed above under the Ex. L-6.5-7 ED-28 heading. As noted there, the IESO responded to both the interrogatory and the subsequent undertaking. ED appears to dispute the IESO's method of calculating Pickering's forced loss rate, but that does not mean that the IESO has not fully responded to the question asked.

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[45] ED Motion, para. 27.

Undertaking JT1.17, Attachment I (re: ED Interrogatory #34)

58. This undertaking is a request for supplemental information based on the IESO's response to Ex. L-6.5-7 ED-34 and requests Pickering's installed capacity and its available capacity at summer peak. The IESO provided a detailed response to the original interrogatory and provided additional information in answering this undertaking, including, in particular, data for installed capacity and assumption for available capacity at peak demand. However, ED complains that the IESO failed to provide the details of its system planning calculations. OPG respectfully submits that the IESO's answer is fully responsive in explaining how it incorporated Pickering's installed and available capacity at summer peak into its analysis.

Undertaking JT1.17, Attachment J (re: ED Interrogatory #36)

59. This undertaking is a request for supplemental information based on the IESO's response to Ex. L-6.5-7 ED-36. Here again, the IESO provided a detailed response to the original interrogatory and provided additional information in answering this undertaking. Specifically, it referred ED to the response to Undertaking JT1.17, Attachment G, which provides the planned and forced outage rates that the IESO used in assessing PEO. Despite ED's complaints to the contrary, the IESO provided a full response to this request.

Conclusion of Reply to ED Motion

60. Arguing that the OEB should use ED's ill-defined "market proxy" to set a ceiling on Pickering costs, ED seeks additional information whose only potential purpose would be to review the Minister's decision to endorse PEO in order to replace Pickering with a resource mix that ED prefers. ED's interrogatories will not assist in developing the concept of a "market proxy." The OEB should firmly reject the attempt to inappropriately alter the focus of this proceeding and reaffirm its consistent findings that OPG's payment amount applications are not the proper forum to review the questions of system planning.

B. REPLY TO GEC MOTION

61. GEC seeks further responses from OPG in respect of the following interrogatories. The request in relation to GEC-001 is supported by ED and OEB staff:

(a) L-3.1-8 GEC-001

(b) L-4.3-8 GEC-002

(c) L-1.3-8 GEC-064

Ex. L-3.1-8 GEC-001

62. To begin, because of the selective, abbreviated way in which the answer to this interrogatory is discussed in GEC's motion, the full question and answer are set out below.

63. GEC's interrogatory reads as follows:

> Concentric notes that the DRP and Pickering life extension as well as the growth in nuclear versus hydraulic assets increases OPG's risk profile which leads to a recommended increase in the equity ratio from 45 to 49%
>
> a) Please confirm that any increase in capital costs due to the size and risk of the DRP will apply to the entire rate base, not just the DRP and Pickering portion.
>
> b) Please estimate how much of the suggested shift in equity ratio is attributable to the DRP and how much is attributable to the Pickering life extension.
>
> c) Please quantify the net present value in total over the life of the Darlington facilities for the increase in the cost of capital for the non-DRP portion of the rate base due to the portion of this shift in risk attributable to the DRP.
>
> d) Please indicate whether the value provided in answer to part c, above, has been included in the $12.8B DRP cost estimate and if so, provide that analysis.
>
> e) Please quantify the net present value in total over the life of the Pickering facilities for the increase in the cost of capital for the non-Pickering portion of the rate base due to the portion of this shift in structure attributable to the Pickering life extension.

f) Please indicate whether the value provided in answer to part e, above, has been included in the cost estimate and in the cost effectiveness studies of the Pickering life extension and provide that analysis.

64. OPG and Concentric's responses to this interrogatory state:

Parts a and b of this response were prepared by Concentric Energy Advisors

a) Confirmed. The proposed change in capital structure will apply to the entire rate base, which includes capital costs of assets in service. It is a standard ratemaking practice to apply one weighted average cost of capital to the utility's rate base that reflects the rate of return (inclusive of capital structure) that would be required for investment in companies of comparable risk. As such, the weighted average cost of capital reflects the entirety of the risk profile of the enterprise. Consistent with that practice, and as described in Concentric's report, Concentric performed a risk analysis of the entirety of OPG's regulated operations, and based the recommendations on that analysis, in conjunction with a comparative analysis of proxy companies to provide context for where, within a reasonable range, OPG's equity ratio should be set by the OEB.

b) As summarized in Concentric's report, the recommended capital structure and associated increase in the equity ratio are based on a number of factors:

- The change in the nuclear to hydroelectric asset mix;
- The increase in OPG's business risk driven by the DRP;
- Plans to pursue extended Pickering operations beyond 2020 and the aging of the Pickering plant;
- The move to IR for hydroelectric rate-setting and to long-term rate-setting periods for nuclear operations;
- The recovery risks associated with pension and OPEB costs and revenue deferred under rate smoothing; and
- OPG's higher risk relative to comparable firms that have a median equity ratio of almost 50% (Ex. C1-1-1, Att. 1, p 5.).

The DRP and Pickering life extension projects are key elements of Concentric's risk assessment, but it is not possible to isolate the effects of these projects, together or individually, from the overall risk assessment of OPG. While one could calculate the increase in capital expenditures for the projects, the capital mix is just one aspect of Concentric's overall risk assessment.

The question is effectively asking for a cost of capital for the DRP, the Pickering Life Extension project and, by default everything else (remaining nuclear operations plus hydro). This would represent an even finer breakdown than a nuclear and hydroelectric specific capital structure, an issue examined by the OEB in EB-2010-0008. In rejecting prior proposals for a technology-specific capital structure in EB-2010-0008, the Board found that: (1) there was a "paucity of comparator firms;" (2) use of technology-specific capital structures would

> introduce a "level of variability and complexity [that] would not be appropriate"; and (3) such an approach "may not lead to any significant ratepayer benefits in the long term."
>
> c) to f) As discussed in response to part b) it is not possible to isolate the effects of these projects from the overall risk assessment of OPG. [Emphasis added.]

65. GEC has no proper complaint with respect to the answer to this interrogatory. The interrogatory asked OPG to quantify the impact on equity ratio resulting from the DRP and PEO. On behalf of OPG, Concentric provided a full, proper answer to the interrogatory. Concentric did not provide an estimate of the incremental effects of the DRP and PEO on OPG's equity ratio in its direct evidence in this proceeding, and Concentric's opinion, as provided in response to GEC-001, is that it is not possible to isolate the effects of these projects, together or individually, from the overall risk assessment of OPG. The fact that GEC may not like the answer makes it neither "evasive" nor "inaccurate".

66. Further, GEC's motion's characterization of the question and answer, in addition to being selective, is premised on a counterfactual which does not exist. To provide an assessment of OPG's risk profile without the DRP and PEO would require the consideration of an entirely different, and non-existent, OPG business plan and long-term outlook.

67. Further, GEC's position fails to appreciate how Concentric arrived at its opinion. Its cost of capital analysis is not purely incremental; rather, it is an assessment performed from the ground-up, taking into account the overall business risk profile of OPG. As explained in the answer to the interrogatory, this exercise involved a detailed and comprehensive assessment of OPG's current risk profile based on a wide range of factors.

68. Tellingly, Concentric's answer is consistent with the approach taken by The Brattle Group, which did not quantitatively attribute a change in equity ratio to either the DRP or PEO.[46] GEC has not posed the same interrogatory to The Brattle Group in respect of its analysis.

[46] Ex. M3, The Brattle Group, *Common Equity Ratio for OPG's Regulated Generation* (November 23, 2016).

69. GEC asserts in its motion that Concentric's response "mistakenly assumes that the purpose of the interrogatory is to support a request for two costs of capital."[47] On the contrary, Concentric made no such assumption in addressing the interrogatory, which asks, in part b), for an estimate on how much of the suggested shift in equity ratio is attributable to the DRP versus PEO. As Concentric points out, the OEB dealt with a similar issue in EB-2010-0008, and found that "the evidence in this proceeding does not provide a sufficiently robust basis to set technology-specific costs of capital, by way of division-specific capital structures".[48] In part b) of the interrogatory response, Concentric notes the obvious implication of the OEB's finding: if there is insufficient evidence in a proceeding where the technology-specific cost of capital was addressed by multiple experts, it would not be possible to attribute cost of capital on an even finer level to specific initiatives within a specific technology division.

70. GEC's argument that the impact of any change in the cost of capital should factor into prudence of DRP costs under Section 6(2), para. 4(ii) of O. Reg. 53/05 is simply misplaced.

71. The regulation establishes the need for the DRP, which has commenced with Unit 2 refurbishment and is underway. The market views OPG's overall risk profile on a forward-looking basis.[49] GEC fundamentally seeks to undermine the intent of O. Reg. 53/05 by trying to factor costs associated with a change in equity ratio into the prudence review.

72. GEC's argument is inconsistent with the OEB's policy on cost of capital. That policy, affirmed in the 2009 Generic Cost of Capital decision, states:

> For electricity transmitters, generators, and gas utilities, the deemed capital structure is determined on a case-by-case basis. The Board's draft guidelines assume that the base capital structure will remain relatively constant over time and that a full reassessment of a gas utility's capital structure will only be

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[47] GEC Motion, p. 3.

[48] EB-2010-0008, Decision with Reasons, p. 116 (see Referenced Materials, p. 23).

[49] Ex. L-3.1-1 Staff-010(b) (see Referenced Materials, p. 59).

> undertaken in the event of significant changes in the company's business and/or financial risk.[50]

73. This policy indicates that the change in risk is the threshold for the "full reassessment", but it does not suggest that the change in risk should be priced separately, but rather considered as part of the full reassessment. To do otherwise would be both impractical and beyond the scope of such a review designed to determine the cost of capital.

74. Finally, regulatory precedent weighs against GEC's position. In considering capital or operating budgets, the OEB has not, historically, considered the cost of capital, which is a separate consideration in establishing revenue requirement.

75. In its submission, OEB staff states that the "scenario analysis requested by GEC may have a net benefit to the OEB's review of this matter" and that "any concerns and the context for the overall risk assessment can be provided with the calculations". This position does not recognize the full scope of Concentric's response, nor the fact that the analysis requested by GEC is not in the nature of "calculations" but would instead, as set out above, require a consideration of an entirely different, and non-existent, OPG business plan and long-term outlook.

76. Similarly, ED suggests that "OPG's consultant could provide ranges rather than a single figure" using "professional judgment and estimation". For the reasons set out above, this too is not feasible.

L-4.3-8 GEC-002 & L-1.3-8 GEC-064

77. In both interrogatories referenced, GEC seeks illustrative examples for the portion of the DRP budget that is avoidable if the program is cancelled or curtailed at various stages (GEC-002), and the estimated impact on payments and customer rates over a 20 year period in the event the Province requires the exercise of an off-ramp at the completion of Unit 2 refurbishment (GEC-064).

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[50] EB-2009-0084 Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (December 11, 2009), p. 50 (see Referenced Materials, p. 63).

78. OPG reiterates its position, as articulated in its responses to these interrogatories, that any attempt at costing such scenarios is a highly speculative exercise since it would be based on assumptions that have neither basis in fact nor relevance to any issue on the approved Issues List. Further, and in any event, OPG would seek OEB direction with respect to any cost implications if an off-ramp is exercised by the Province during the period covered by the Application.[51]

79. The 2013 LTEP sets out the refurbishment principles applicable to the DRP, including the establishment of appropriate and realistic off-ramps.[52] As explained in OPG's pre-filed evidence[53] and interrogatory responses[54], the contracts for the DRP major work bundles have been structured to include off-ramp provisions with specific criteria. However, neither the LTEP nor the Province's January 11, 2016 endorsement of the DRP contemplates that OPG is to plan for or price out specific off-ramp scenarios. To this end, OPG has not prepared any plan for off-ramping the DRP nor has it established any cost thresholds or schedule delays where the company would consider cancelling the refurbishment of Units 1, 3 and 4.[55] It is not of assistance to the OEB for OPG to address the cost implications of speculative scenarios which are beyond the scope of the Application and this proceeding.

80. Furthermore, if one of the off-ramp scenarios suggested by GEC did materialize, there would be implications far beyond the contracting and program plan for the DRP. This would result in an entirely different OPG business plan and long-term outlook. The business plan and long-term outlook are based on completing the DRP on a four-unit basis. If this does not occur or a different approach was employed, the plan and investments made and to be made would be drastically different such that a wholly different application would have been made.[56] As explained by OPG's interrogatory

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[51] Ex. L-4.3-8 GEC-002 (see Referenced Materials, p. 64); and Ex. L-1.3-8 GEC-064 (see Referenced Materials, p. 65).

[52] LTEP 2013, p. 29 (see Referenced Materials, p. 67).

[53] Ex. D2-2-1, Attachment 2, p. 2 (see Referenced Materials, p. 69).

[54] See: Ex. L-4.3-8 GEC-008 (see Referenced Materials, pp. 71-72); and Ex. L-4.3-1 Staff-050 (see Referenced Materials, pp. 73-75).

[55] Ex. L-11.7-6 EP-035 (see Referenced Materials, p. 76).

[56] Transcript Vol. 1 of Technical Conference (November 14, 2016), p. 87 (see Referenced Materials, p. 78).

response in L-4.3-8 GEC-009, in the event that the remaining three units were not to be refurbished, their respective shutdowns are expected to occur in the span of a few years, resulting in fundamental changes across OPG's entire business, including with respect to labour strategies, decommissioning plans, applicable regulatory requirements, and financing and cash flow needs, as examples.[57] If and when this were to occur, (the circumstances of which are currently completely unknown) then OPG would at that time make an application for relief and be subject to the OEB's review. To price these implications prior to them occurring would be highly speculative and would not advance the consideration of the issues in this proceeding.

81. For these reasons, OPG is not in a position to provide further responses in respect of L-4.3-8 GEC-002 and L-1.3-8 GEC-064.

82. In its December 9 submission, OEB staff recognizes the degree of speculation and uncertainty involved in these interrogatories, and invites GEC to provide clarification at the motion hearing. For the reasons set out above, an attempt to price out off-ramps would require significant re-planning efforts by OPG. Any clarification provided by GEC at the motion hearing is unlikely to adequately address the wide range of speculative assumptions and issues entailed in such an exercise, including those identified in paragraph 80.

C. REPLY TO SEC MOTION

83. OPG intends to file the information requested by SEC in interrogatory L-11.1-15 SEC-95 by December 22, 2016.

CONCLUSION

84. For the reasons set out above, OPG submits that the motions filed by ED and GEC should be dismissed.

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[57] Ex. L-4.3-8 GEC-009 (see Referenced Materials, p. 79).

All of which is respectfully submitted, this 13th day of December, 2016.

ONTARIO POWER GENERATION INC.

By its Counsel Torys LLP

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Charles Keizer

____

Crawford Smith

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. pursuant to section 78.1 of the Act for an order or orders approving payment amounts for prescribed generating facilities commencing January 1, 2017;

AND IN THE MATTER OF Rules 8 and 27 of the Board's *Rules of Practice and Procedure*.

OPG REPLY SUBMISSIONS TO MOTIONS

COMPENDIUM OF REFERENCED MATERIALS

Electricity Act, 1998
S.O. 1998, CHAPTER 15
Schedule A

Consolidation Period: From July 1, 2016 to the e-Laws currency date.

Last amendment: 2016, c. 10, Sched. 2, s. 1-10.

…

PART II.2
PLANNING, PROCUREMENT AND PRICING

Long-term energy plans

25.29 (1) At least once during each period prescribed by the regulations, the Minister shall, subject to the approval of the Lieutenant Governor in Council, issue a long-term energy plan setting out and balancing the Government of Ontario's goals and objectives respecting energy for the period specified by the plan. 2016, c. 10, Sched. 2, s. 7.

Same

(2) For the purposes of subsection (1), a long-term energy plan may include goals and objectives respecting,

(a) the cost-effectiveness of energy supply and capacity, transmission and distribution;

(b) the reliability of energy supply and capacity, transmission and distribution, including resiliency to the effects of climate change;

(c) the prioritization of measures related to the conservation of energy or the management of energy demand;

(d) the use of cleaner energy sources and innovative and emerging technologies;

(e) air emissions from the energy sector, taking into account any projections respecting the emission of greenhouse gases developed with the assistance of the IESO;

(f) consultation with aboriginal peoples and their participation in the energy sector, and the engagement of interested persons, groups and communities in the energy sector; and

(g) any other related matter the Minister determines should be addressed. 2016, c. 10, Sched. 2, s. 7.

Technical reports by IESO

(3) The Minister shall, before issuing a long-term energy plan under subsection (1), require the IESO to submit a technical report on the adequacy and reliability of electricity resources with respect to anticipated electricity supply, capacity, storage, reliability and demand and on any other related matters the Minister may specify, and the Minister shall,

(a) consider the report in developing the long-term energy plan; and

(b) post the report on a publicly-accessible Government of Ontario website or publish it in another manner, before undertaking any consultations under subsection (4). 2016, c. 10, Sched. 2, s. 7.

Consultation required

(4) The Minister shall, before issuing a long-term energy plan under subsection (1), consult with any consumers, distributors, generators, transmitters, aboriginal peoples or other persons or groups that the Minister considers appropriate given the matters being addressed by the long-term energy plan, and the Minister shall consider the results of such consultation in developing the long-term energy plan. 2016, c. 10, Sched. 2, s. 7.

Notice

(5) The Minister shall publish notice of consultations under subsection (4), together with any relevant background materials or other information the Minister considers appropriate, in the environmental registry established under section 5 of the *Environmental Bill of Rights, 1993*. 2016, c. 10, Sched. 2, s. 7.

Participation

(6) The Minister shall take steps to promote the participation of the persons or groups with whom the Minister intends to consult under subsection (4), including,

(a) scheduling one or more consultation meetings, where the Minister considers it appropriate to do so, that the persons or groups are entitled to attend in person; and

(b) providing for the participation of persons or groups in consultations through electronic or other means not requiring personal attendance. 2016, c. 10, Sched. 2, s. 7.

Publication

(7) On issuing a long-term energy plan under subsection (1), the Minister shall post it on a publicly-accessible Government of Ontario website or publish it in another manner, and shall also post or publish any other information, such as key data and cost projections, used in the development of the long-term energy plan that the Minister determines should be made publicly available. 2016, c. 10, Sched. 2, s. 7.

…

Ontario

NEWS

Ministry of Energy

Ontario Moving Forward with Nuclear Refurbishment at Darlington and Pursuing Continued Operations at Pickering to 2024

Projects will Boost Economic Activity, Create Jobs and Help Fight Climate Change

January 11, 2016 2:00 P.M.

Ontario is moving forward with nuclear refurbishment at Darlington Generating Station, securing 3,500 megawatts of affordable, reliable, and emission free power.

Nuclear refurbishment at Darlington will contribute $15 billion to Ontario's gross domestic product (GDP) throughout the project and create up to 11,800 jobs annually. The refurbishment of all four units is expected to involve about 30 million hours of work over 10 years and will support Ontario's globally recognized CANDU nuclear supply chain, with more than 180 companies employing thousands of highly skilled workers.

Ontario Power Generation (OPG) is on track to begin refurbishment of the first unit at Darlington in October 2016. To best protect Ontario ratepayers and ensure OPG delivers refurbishment on-time and on-budget, the government has established off-ramps that require OPG to obtain government approval prior to proceeding with each of the remaining unit refurbishments. The budget for the project is $12.8 billion, about $1.2 billion less than originally projected by OPG, and all four units are scheduled for completion by 2026.

The Province has also approved OPG's plan to pursue continued operation of the Pickering Generating Station beyond 2020 up to 2024, which would protect 4,500 jobs across the Durham region, avoid 8 million tonnes of greenhouse gas emissions, and save Ontario electricity consumers up to $600 million. OPG will engage with the Canadian Nuclear Safety Commission and the Ontario Energy Board to seek approvals required for the continued operation of Pickering Generating Station.

Securing clean, reliable power for decades to come is part of the government's plan to build

Ontario up. The four-part plan includes investing in people's talents and skills, making the largest investment in public infrastructure in Ontario's history, creating a dynamic, innovative environment where business thrives and building a secure retirement savings plan.

QUOTES

" Proceeding with the refurbishment at Darlington will ensure that nuclear continues to be Ontario's single largest source of power. The Darlington refurbishment project will create up to 11,800 jobs annually and contribute $15 billion to Ontario's GDP. Continuing operations at Pickering will protect 4,500 jobs across the Durham region, provide emissions-free electricity, and save Ontario electricity consumers up to $600 million."
- Bob Chiarelli
Minister of Energy

" Refurbishing Darlington is an investment in Ontario. It's good for the customers, it's good for the economy and it's good for the environment. We're confident we have done the work and have the people in place to deliver this project safely, on schedule and on budget."
- Jeffrey Lyash
President and CEO, Ontario Power Generation

" With these investments, nuclear will continue its role in ensuring Ontarians have enough power when and where they need it. The plan to refurbish the Darlington nuclear units and to keep Pickering in operation longer during the refurbishment period is a cost effective way to meet our future power needs."
- Bruce Campbell
President and CEO, Independent Electricity System Operator

QUICK FACTS

- Nuclear energy plays a fundamental role in Ontario's electricity system. Ontario's nuclear fleet currently supplies enough power to meet about 60 per cent of Ontario's daily electricity needs, and is our largest source of reliable, affordable power.
- OPG electricity rates are regulated by the Ontario Energy Board (OEB). All costs for the Darlington refurbishment will be subject to review and approval by the OEB through a public and transparent process to ensure they are prudently incurred. The average cost

of power from Darlington nuclear units post-refurbishment is estimated to range between $72/MWh and $81 MWh, or 7 and 8 cents per kilowatt hour.

- The average cost of power from Darlington after refurbishment is within the range assumed in the 2013 Long-Term Energy Plan for refurbished nuclear energy and lower than the average price of electricity generation in Ontario, which in 2015 was $92/MWh.
- The Pickering Generating Station employs about 4,500 people and is the largest employer in Durham Region.
- Continuing operations at Pickering Generating Station will avoid 8 million tonnes of greenhouse gas emissions, which is the equivalent to taking 490,000 cars off Ontario roads.

LEARN MORE

- Learn about OPG's Darlington Refurbishment Project
- Read the Conference Board of Canada's report on the economic impact of the Darlington Refurbishment
- Read Ontario's 2013 Long-Term Energy Plan

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Ontario Power Generation is also seeking regulatory approvals to allow it to operate the Pickering station until 2024. After that, it will be shut down and decommissioned. Keeping Pickering running until 2024 will ensure the province has a reliable source of GHG-free baseload electricity to carry it through the refurbishment of the Darlington and the initial Bruce units.

The nuclear industry is made up of over 180 companies and is an important driver of Ontario's economy, employing about 60,000 people and generating billions of dollars in economic activity every year. Nuclear companies and research laboratories in communities across Ontario have expertise in the design and construction of sophisticated systems and components for current and future reactors. In addition to being used in all of Ontario's nuclear plants, the Ontario-developed CANDU nuclear technology was exported to Argentina, Romania, South Korea, China, Pakistan and India. The Darlington and Bruce refurbishments will support Ontario's globally-recognized nuclear industry for decades to come.

Clean Electricity Trade

The 2013 LTEP committed the government to seeking out agreements with other jurisdictions for the import of clean energy, where such imports would benefit the province's electricity system and be cost-effective for Ontario ratepayers. This commitment led to discussions with Quebec, Manitoba and Newfoundland and Labrador.

Discussions with our provincial neighbours on potential electricity trade agreements were guided by the goals of reducing emissions, reducing costs for Ontario ratepayers, and supporting existing initiatives such as the development of a capacity auction.

CCC Interrogatory #32

Issue Number: 6.5
Issue: Are the test period expenditures related to extended operations for Pickering appropriate?

Interrogatory

Reference:
Reference: Ex. F2/T2/S3/p. 1

What specific approvals is OPG seeking from the OEB with respect to the Pickering Extended Operations through this Application?

Response

OPG seeks approval of the Nuclear Revenue Requirement (see Ex. A1-2-2, page 1, Line 8), which includes forecast OM&A expenditures, to enable Pickering Extended Operations and normal operating expenditures at Pickering during the test period, as shown in Ex. F2-2-3, page 4, Chart 1. OPG is also seeking approval of the Nuclear rate base (see Ex. A1-2-2, page 1, Line 13), which includes Pickering related in-service additions as shown in Ex. B3-3-1, Table 2. Finally, OPG is seeking approval of its Nuclear production forecast (see Ex. A1-2-2, page 2) which includes the impacts of outages as well as the 2021 production attributable to Pickering Extended Operations, as shown in Ex. E2-1-1, p. 4 and Table 1, BLOG

WE NEED MORE, NOT LESS, GREEN ENERGY

SEP 27 2016

Keith Brooks
Programs Director

Categories: Clean Economy, Climate Change,

The Ontario government caught everyone by surprise when it announced the suspension of plans to procure more wind and solar power. Ontario has shown great leadership in supporting green energy. Now is not the time to back away. It's time to double down.

Tell Ontario to support more green power.

Globally, renewable energy development continues to soar. 2015 marked the second year in a row that more money was invested in green energy than in new fossil fueled generation. Green energy costs are dropping like a rock. Wind power prices have come down **66 per cent over the past six years**. Recent bids for solar power in **Dubai** and **Chile** were under three cents per kilowatt hour – making solar the cheapest form of electricity generation available.

The future looks even brighter – Bloomberg New Energy Finance estimates that some **$8 trillion will be invested** in renewable power over the next 25 years.

Ontario has been at the forefront of this technological revolution. The province is the third largest producer of solar power in North America and the fifth largest for wind. This commitment has meant cleaner air, more jobs, and new economic opportunities for Ontarians.

Thanks to the coal closure, Ontario avoids an estimated $4.4 billion in health and environmental costs each year. It's not a coincidence that after closing the coal plants, smog days disappeared.

Green energy has also created tens of thousands of jobs and there are dozens of companies now part of Ontario's green energy supply chain. These companies add billions of dollars every year to Ontario's economy. And Ontario's support for wind and solar has allowed farmers, faith groups, First Nations, schools, and municipalities, among others, to participate in, and reap returns from, green energy. (Read our report, **Getting FIT**, for the complete picture)

Now is the time to **ramp up green energy** not back away from it.

Green energy is very popular in Ontario. **Polling done by EKOS** found that 81 per cent of Ontarians want to see more renewable energy in the future. And 74 per cent of Ontarians supported the move away from coal toward wind and solar.

The claims that green energy is leading to skyrocketing hydro bills **are false**. Wind and solar still make up relatively small percentages of the total electricity supply, and have a small impact on bills. Nuclear power is actually the largest part of Ontarians bills.

The government says they are suspending the procurement of renewable power because of an imbalance between supply and demand. But if they want to get back to balance, maybe they should begin by closing the aging Picking Nuclear plant, instead of extending it past its planned lifetime – and putting people at risk if there's an accident.

Green energy is cost effective here in Ontario. The Independent Electricity System Operator's (IESO) own **planning outlook** shows that green energy costs are on par with nuclear power or natural gas. Some contracts recently signed for wind power in Ontario are cheaper that what we pay for nuclear power.

Ontario, an early leader in green power, is in a position to benefit from the global surge in renewable power – but if we hope to reap the benefits, we must continue investing in renewable energy at home.

Suspending the renewable energy procurement sends the wrong signal to Ontarians and to the world. Fortunately, the province is about to review its Long Term Energy Plan. Now is the time to tell Ontario you support more renewable power.

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

VT INCEPIT FIDELIS SIC PERMANET
Ontario

EB-2013-0321

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES FOR 2014 AND 2015

DECISION WITH REASONS

November 20, 2014

In the first cost of service proceeding, the Board found that the benchmarking filed was insufficient. As a result, the Board directed OPG to retain an expert to prepare a comprehensive benchmarking analysis of OPG's nuclear operations. OPG filed benchmarking reports that assessed 2008 performance prepared by ScottMadden Inc. for the EB-2010-0008 proceeding. OPG has adopted the ScottMadden reporting format and annually benchmarks its nuclear performance against "20 performance metrics and then sets operational, financial and generation performance targets that will move OPG nuclear closer to top quartile industry performance over the business planning period as part of top-down business planning process adopted in response to ScottMadden's work."[34]

The results of OPG's benchmarking of three key metrics for the nuclear facilities for the period 2008 to 2013, and the targets for 2014 and 2015 are summarized in the following table.[35] The three key metrics identified by ScottMadden are World Association of Nuclear Operators Nuclear Performance Index, Unit Capability Factor and Total Generating Costs per MWh. Note that Pickering A and B were combined by OPG after 2010, and therefore the units are not ranked separately by OPG after that time (though ScottMadden had created separate targets for Pickering A and B in its 2009 report). OPG has performed very poorly on all three of the key metrics.

[34] Reply Argument page 139
[35] Undertaking J5.2

OPG's CANDU plants require 1,431 more Full Time Equivalents ("FTEs") than comparator plants and eliminated these FTEs from the staffing study. OPG estimated that this represents $184M of unavoidable OM&A.

As the shareholder has concurred with the business plans that underpin the application, OPG replied that the shareholder has no concerns with OPG's performance under the Memorandum of Agreement.[38] OPG argued that it is not contractually committed to, or required to target or perform to top quartile standards, and that it is not aware of any case where the Board considered failure to achieve top quartile performance in setting rates.

Board Findings

The benchmarking of OPG's nuclear operations is an important reference for the Board. OPG has continued to produce annual nuclear benchmarking reports based on the format and methodology set out in 2009 by the consulting firm ScottMadden. The benchmarking is responsive to the Memorandum of Agreement with the Shareholder and provides the Board with comparative information for its review in a cost of service application. It is the Board's expectation that OPG will continue to produce annual nuclear benchmarking reports based on the ScottMadden methodology and that OPG will file these reports in future cost of service applications.

The benchmarking results for 2008 to 2013 and the targets for the test period were reviewed in this proceeding. The analysis was complicated by the presentation of rolling averages for the historical period and annual targets for the future period. The analysis was further complicated by the reorganization of Pickering. The Board recognizes that some individual units at Pickering and Darlington have improved performance in one or more of the metrics. In OPG's view, it has improved as a major operator in the three key metrics, but in comparison to the industry, OPG is just stable, because the industry also is changing.

Despite these factors, there is no dispute that OPG's performance in the three key metrics is not top quartile, nor does it demonstrate continuous improvement. In fact, for many of the measures OPG remains in the third or fourth quartile. It is also reasonable to conclude that OPG will not reach the aspirational 2014 targets set by ScottMadden and OPG in 2009 in order to close the gap. This is not the type of performance that

[38] Reply Argument page 134

ratepayers would expect. OPG is not satisfied with its performance either: "… clearly we would like to see better performance from our plants."[39]

In its submission, Board staff included calculations of the cost of OPG's performance relative to the midpoint for comparators' total generating cost for 2011 for illustrative purposes. CME submitted that a $150M OM&A reduction per year was appropriate on the basis of this gap. The Board agrees with OPG that reductions of $150M to $300M per year on the basis of nuclear benchmarking is not appropriate as the impact of Business Transformation is not reflected in the 2011 total generating costs. However, the Board notes that OPG's total generating cost targets for 2014 and 2015 take into account Business Transformation and those targets are second and third quartile.

OPG also argued that the Board staff and CME calculations were flawed as there is unavoidable OM&A related to the CANDU technology. The Board does not agree that the calculations were flawed for this reason. The ScottMadden methodology, which has been accepted by OPG for benchmarking, considered technology differences and found that the best overall financial comparison metric for OPG facilities is total generating cost per MWh.

Both Environmental Defence and GEC have proposed significant reductions related to poor economic performance of the Pickering units. The Board does not agree with these submissions. The government's direction on the operation of Pickering is set out in the Long-Term Energy Plan.

The Board finds that OPG's proposed nuclear OM&A costs should be reduced. The Memorandum of Agreement provides that "OPG's top operational priority will be to improve the operation of its existing nuclear fleet." In conjunction with ScottMadden, OPG itself set targets for 2014 that will not be met. Although the Memorandum of Agreement is not a contract for this purpose, it is clearly OPG's shareholder's intention that OPG improve continually, and at least target top quartile performance. OPG accepts that benchmarking is a valuable tool, and accepts that it has not achieved the results it wanted to achieve. It does not appear to accept, however, that there should be any repercussions from this poor performance in the way of disallowances. Benchmarking serves as a guide only. However, it is clear that OPG's inability to achieve even average performance imposes a significant cost on ratepayers. The Board finds that it is not reasonable to pass all of these costs on to ratepayers.

[39] Tr Vol 6 page 13

GEC observed that there is a considerable difference between the continued operations benefit determined by OPG and the OPA. GEC questioned the factors analyzed in the sensitivity analysis. In particular, GEC questioned whether the full cost of surplus baseload generation was considered by OPG and the OPA. In GEC's view, the Board should not approve payment amounts that have a perverse effect on ratepayers. As the economic benefit of continued operations is questionable, GEC submitted that the incremental cost of running Pickering in the test period ($126M in 2014 and $310M in 2015) should be disallowed.

OPG argued that OPA analysis did consider potential surplus energy and that this was confirmed in the written responses filed by the OPA on July 25, 2014.

GEC recognizes that operation of some Pickering units has system planning benefits, however, as units 1 and 4 (formerly Pickering A) under-perform on all benchmarking indicators versus units 5 to 8 (formerly Pickering B), GEC submitted that the Board should not "reward" OPG for the continuing losses with respect to units 1 and 4. OPG replied that it operates Pickering as one station and that the Long-Term Energy Plan includes Pickering in-service beyond the test period.

GEC submitted that $6.6M of test period expense allocated to Pickering for the fuel channel life extension project should be allocated to Darlington as the additional fuel channel life is not required for Pickering station life of 2020. However, OPG argued that an objective of the fuel channel life extension project is to operate all Pickering units to 2020 without a life management outage on any unit.

In the event the Board is not prepared to implement cost reductions related to Pickering, GEC submitted that the Board should require OPG to provide, in the next payment application, a detailed analysis of the net benefits of continued operation of Pickering units. GEC further submitted that the analysis should consider shutdowns of either the A or B units or all units, including staffing considerations. OPG argued that the study should not be ordered and that the Board should rely on the Long-Term Energy Plan.

Board Findings

The Board approves the OM&A costs in the amount of $38.9 M to enable the completion of the initiative to extend the operating life of Pickering units 5 to 8 to the year 2020. The Board finds these costs to be prudent and notes that this initiative is on time and on budget to be completed by the end of 2014.

The 2014 costs to complete the continued operations initiative include Fuel Channel Life Extension costs. The Board does not accept GEC's argument that these should be disallowed or reallocated to Darlington. OPG's evidence demonstrates that these costs are related to Pickering continued operations.

It is important to recognize that the extension of the Pickering units is consistent with the Province of Ontario's Long-Term Energy Plan. Further, benefits from Pickering continued operations were confirmed by the OPA. Lastly, the continued operations of Pickering has been reviewed by the Canadian Nuclear Safety Commission resulting in the renewal of Pickering's power reactor operating license to August 31, 2018.

Challenges to the value and economic merits of the Pickering continued operations were made by GEC and AMPCO, including whether the analysis was incorrect as the assessment omitted the impact of surplus generation. The Board accepts OPG's evidence that surplus baseload generation was included in the OPA's analysis.

The Board reiterates its view that the project is consistent with government direction, and that benefits (while significantly reduced from OPG's estimate) were determined by the OPA to be positive. The OPA also brought to the Board's attention the non-economic benefits of Pickering Continued Operations. For these reasons, the Board does not see the value of directing OPG to complete a detailed analysis of the net benefits of continued operation of Pickering units.

3.5 Nuclear Capital Expenditure and Rate Base

(Issues 2.1, 4.6, 4.7 and 4.8)

OPG has applied for total capital expenditures of \$196.3M in 2014 and \$143.9M in 2015, excluding the Darlington Refurbishment Project. The proposed capital expenditure for 2014 represents a decrease over 2013 actuals. OPG states that the decrease in 2015 is due to a reduction in the number of capital projects. OPG also seeks Board approval for nuclear in-service additions of \$158.3M for 2014 and \$141.7M for 2015.

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

EB-2007-0905

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES

DECISION WITH REASONS

November 3, 2008

Regarding the suggestion that the OM&A budget should be treated on an envelope basis, OPG responded that while it should be free to manage specific expenditures within an OM&A envelope, it is opposed any determination of the OM&A costs through a benchmarking exercise.

Board Findings

This aspect of the decision gives rise to two significant issues. The first is whether the Board has the jurisdiction to determine the viability of the Pickering stations. The second is the extent to which the Board should use the detailed benchmarking evidence to assess the reasonableness of the costs OPG seeks to recover.

With respect to the first issue, the Board agrees with OPG that the Board's role in this application is to review the proposed costs of the prescribed facilities and to order reasonable payment amounts.

As discussed in Chapter 9 of this decision, the Board has rejected OPG's proposed payment structure for the nuclear plants (which was to include a fixed amount of $1.2 billion during the test period plus a per MWh payment amount to cover the balance of the revenue requirement). Instead, the Board has decided to retain the current variable payment structure of an amount per MWh regardless of the level of production. If OPG operates its plants at a unit cost higher than the approved payment amount, the excess costs will be borne by OPG and its shareholder. Consumers will not be at risk for costs in excess of the costs used to set the payment amount. Therefore, the Board does not accept the suggestion of intervenors that it order OPG to file a study on the long-term viability of Pickering. The long-term viability of the Pickering stations is an assessment more properly made by the shareholder knowing that the Board will only allow the recovery of reasonable costs and that the payment structure will be such that consumers will not bear production risk.

The benchmarking issue is more important. The direction given by the Province to OPG in the MOA is very specific. OPG is directed to seek "continuous improvement in its nuclear generation business." To this end, the MOA states: "OPG will benchmark its performance in these areas against CANDU Nuclear plants worldwide as well as against the top quarter of private and publicly owned nuclear electricity generators in North America." And finally, the MOA states: "OPG's top operational priority will be to improve the operation of its existing nuclear fleet."

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

EB-2010-0008

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES FOR 2011 AND 2012

DECISION WITH REASONS

March 10, 2011

benefits of the project appear to be over stated. SEC submitted that OPG should curtail further spending until an independent analysis of the benefits is carried out.

OPG argued that no parties provided competing analyses of the benefits. In OPG's view, references to the assumptions used in its analysis were selective and it is clear that the OPA supports the test period expenditures. OPG further submitted that using Total Generating Cost for the benefits analysis should be rejected since it includes costs that will exist notwithstanding the shutdown of Pickering. With respect to unit capability factors, OPG noted that it had performed a sensitivity analysis with varying levels of unit capability factors and the net present value is significantly positive even for the lower end of the range.

Board staff argued that, given the confidence expressed by OPG's witnesses that the project will come in on budget and that no contingency is required, there should be no need to use the capacity refurbishment variance account. If the Board has discretion, staff recommended that the Board restrict the use of the account to those costs that are not routine OM&A activities (i.e., the fuel channel life cycle management project). Staff also noted its concerns that OPG stated it is counting on the variance account to the extent a contingency is required. AMPCO supported the approach proposed by Board staff. OPG maintained that the entire project is clearly within the scope of the account. OPG noted that even work for which there is high confidence can have a variance. Further, if the project comes in under budget, excluding it from the variance account would mean that ratepayers would be denied a credit.

Board Findings

The Board approves $84.1 million in costs for Pickering B Continued Operations in this test period.

In this proceeding, the Board is of the view that its role is limited to determining the following:

- whether the planned spending on the Pickering B Continued Operations in 2011 and 2012 is reasonable based on the business case; and
- whether OPG's decision not to extend the end of life for Pickering B for accounting purposes is reasonable. This issue is addressed in Chapter 8.

The Board will consider spending for years beyond the current test period in OPG's next application, at which time there will be examination of the progress to date and an assessment of project economics and the company's confidence level on the basis of that experience and more current information.

With respect to the planned spending during the test period, the Board has determined that the proposed O&M budget is reasonable, except for the double counting of the fuel channel life cycle management project which will be corrected. The Board is satisfied that the business case substantiates the reasonableness of test period expenditures. However, the Board does have concerns with respect to the analysis. Parties have raised a number of other issues regarding the specifics of the benefits analysis, including the unit capability factors, the price used for comparative purposes and the absence of a contingency component in the cost estimate. The Board expects OPG to address these issues more fully in its next application when the Board considers the next segment of spending, as well as any variance in the account. In seeking to provide the best evidence, OPG should consider seeking an independent assessment by the OPA to be filed with its next application.

With respect to the operation of the variance account, the Board agrees with OPG that section 6(2)4 of O. Reg. 53/05 applies to Pickering B Continued Operations as the project is designed to increase output of a generating facility to which O. Reg. 53/05 applies.

Although this project is to be funded entirely through operating expenditures, it has many similarities with a capital project because O. Reg. 53/05 requires the tracking of any variances through the operation of the capacity refurbishment variance account. In the normal course, for projects funded through operating expenditures, the company would bear the risk of budget variances and would therefore need to manage the costs within its overall revenue envelope. For this project, however, any variances will be captured in the variance account for later prudence determination by the Board. The Board is concerned that ratepayers bear a particular risk in relation to these large nuclear projects, which have a history of going over budget. In examining the prudence of any incremental expenditure (over the approved level for the test period) the Board will consider whether OPG might prudently have offset the cost increases through cost reductions or cost deferrals elsewhere in its operations.

If the Board is inclined to approve separate capital structures, OPG submitted that the only reasonable ratios would be 45% for the regulated hydroelectric business and 50% for nuclear. OPG also argued that Board staff is incorrect in concluding that cost of debt is specific to projects, noting that the cost of debt for the projects identified in the staff submission reflect OPG's corporate borrowing costs.

Board Findings

OPG has applied the same capital structure as was approved on a combined basis for its regulated hydroelectric and nuclear generation assets in the previous payments case. The Board finds that there is no evidence of any material change in OPG's business risk and that the deemed capital structure of 47% equity and 53% debt, after adjusting for the lesser of Unfunded Nuclear Liabilities or Asset Retirement Costs, remains appropriate.

The Board accepts that the business risks associated with the nuclear business are higher than those of the regulated hydroelectric business, and this is not contested by parties in this hearing. However, the Board finds that the evidence in this proceeding does not provide a sufficiently robust basis to set technology-specific costs of capital, by way of division-specific capital structures. In short, the Board finds an inadequate body of evidence to support a change from the conclusions reached by the Board in the previous proceeding.

The evidence of Drs. Kryzanowski and Roberts is a heuristic approach and is qualitative as much as quantitative in nature. Their evidence also largely employed the same techniques as contained in their evidence in the previous case. The difficulty for the Board is the dependence on qualitative assumptions and analysis. Their qualitative assessments of various forms of risk give rise to quantitative scorings that they then have translated into different capital structures corresponding to a cost of capital related to the risks of each business division and constrained by two conditions:

1) the weighted aggregate cost of capital for the two divisions should correspond with the 47% equity thickness set by the Board on an aggregate basis; and
2) the cost of capital and hence the deemed capital structure for the hydroelectric division should be commensurate with a business risk no less risky than that for electricity distributors and transmitters, for which the Board has deemed a 40% equity thickness.

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

EB-2013-0321

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

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an order or orders determining payment amounts for the output of certain of its generating facilities.

DECISION AND ORDER ON ISSUES LIST AND PROCEDURAL ORDER NO. 10

June 4, 2014

Ontario Power Generation Inc. ("OPG") filed an application, dated September 27, 2013, with the Ontario Energy Board under section 78.1 of the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15, Schedule B seeking approval for increases in payment amounts for the output of its nuclear generating facilities and the currently prescribed hydroelectric generating facilities, to be effective January 1, 2014. The application also seeks approval for payment amounts for newly prescribed hydroelectric generating facilities, to be effective July 1, 2014.

Issues List

The School Energy Coalition ("SEC") filed correspondence with the Board on May 26 and May 28, 2014 requesting that nine issues on the issues list provided on May 16, 2014 in the Decision on Motions, Issues List and Confidential Filings and Procedural Order No. 9, be reprioritized from secondary to primary. Based on discussions during the settlement conference, SEC states that there is a clearer picture of what still has to be put on the record. SEC states that oral evidence and cross examination on these issues are required for the Board to determine the payment amounts. SEC seeks reprioritize, or partially reprioritize, some issues from secondary to primary so that recently obtained information on the continued operations of Pickering units 5 to 8 can be tested through oral evidence. The secondary issues are 5.2, 6.6, 6.11, 6.12, 8.1 and 8.2. GEC states that much of the new information relates to primary issue 5.5 and oral hearing issue 6.3, but that there are implications for the secondary issues noted. GEC stated that the Board could limit the reprioritization of the secondary issues to matters related to the new information on Pickering.

In correspondence filed on June 3, 2014, OPG replied that GEC's request attempts to circumvent the Board's decision on the issues list in Procedural Order No. 3. The documents referred to by GEC pre-date the OPA letter relating to Pickering Continued Operations filed in OPG's application, and GEC's assertions should be given no weight. The Board is required to set payment amounts while generation planning decisions are in the realm of the OPA and the ministry.

GEC replied that OPG mistakenly equates GEC's request for reprioritization of secondary issues, with a request for the Board to shutdown Pickering. GEC noted that it agrees that shutting down Pickering is a government decision. That does not relieve the Board of its obligation to set payments that ensure value for customers, to consider the implications of running Pickering on SBG, or to recognize uncertainties in Pickering life expectancy that affect depreciation or liabilities. GEC stated that all of the foregoing are within scope of the current issues list.

GEC also noted that in the EB-2010-0008 Decision, the Board expressed concern about Pickering costs and made specific reference to the need for an independent assessment of the cost effectiveness of the life extension. GEC stated that the information obtained from the OPA was in response to an FOI for information that was behind the OPA letter to OPG.

OPG filed an additional reply noting that nothing in the GEC reply changes OPG's position on this matter.

The Board agrees with OPG that generation planning is not within the scope of this proceeding. However, the costs sought for Pickering continued operations throughout the test period are within the scope and to the extent that the recently obtained information can be helpful in assessing the reasonableness of those costs, the Board is

ONTARIO POWER GENERATION

November 2015

File: P-BCS-00970-0001 REV: 000

Technical and Economic Assessment of Pickering Extended Operations beyond 2020

October 2015

Contents

Table 6 summarizes the generation forecasts developed for the extended operations Preferred Alternative.

Table 6: Estimated Generation Impacts of the Preferred Alternative

Generation Plan		2016 - 2020	Post 2020	Total
OPTION 1	Additional Planned Outage Days	630	1,103	**1,734**
	Incremental TWh	-7.4	71.9	**64.5**
OPTION 2	Additional Planned Outage Days	637	1,354	**1,991**
	Incremental TWh	-7.5	68.9	**61.5**

The additional outage days in the period 2016 to 2020 are associated with incremental inspections required to enable the Preferred Alternative, as well as restore normal planned outages and durations in 2020 that would have been reduced or not necessary in the Base Case (planned shutdown in 2020).

The planned outage days in the period 2021 to 2024 are associated with operation of the units for the additional 2 and 4 calendar years (a total of 20 additional unit-years). The two options reflect the range of outcomes required to execute inspection and maintenance activities necessary to maintain fitness for service of plant equipment.

ECONOMIC ASSESSMENT SUMMARY

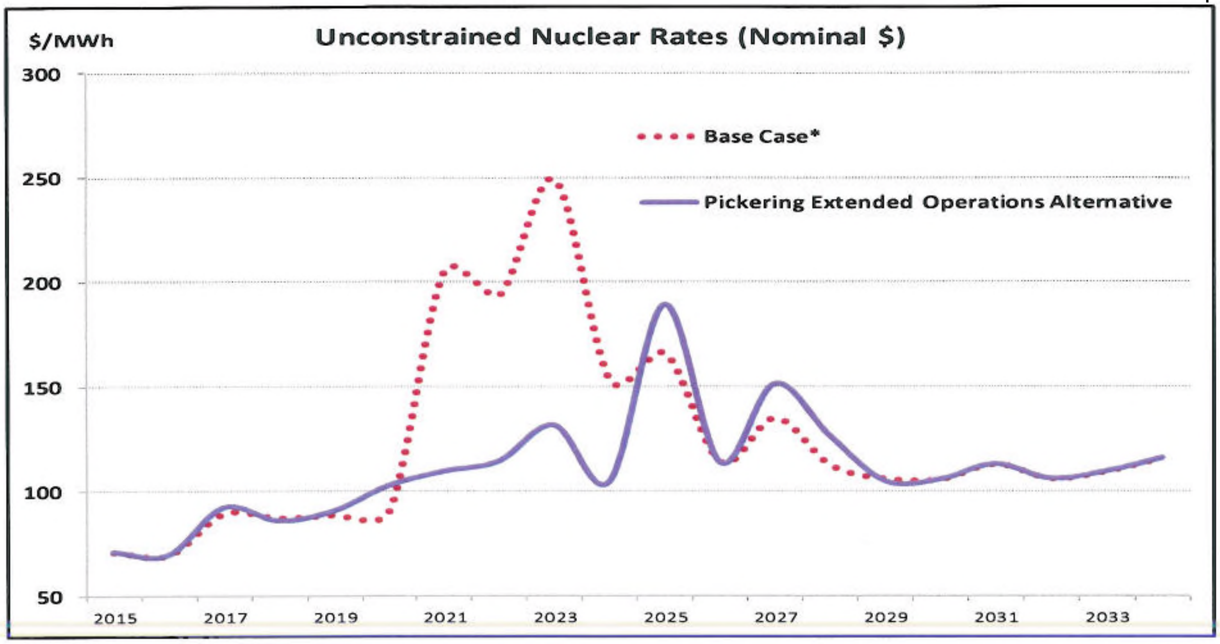
The Levelized Unit Energy Costs (LUEC) of the Preferred Alternative, i.e. the LUEC associated with the incremental costs and generation relative to the Base Case, is evaluated at 6.2 ¢/kWh to 6.5 ¢/kWh for the two options. LUEC calculations exclude the benefit of deferring severance and related costs.

The Preferred Alternative also provides a number of quantitative economic advantages for both the ratepayer and OPG. The major economic advantages are:

- **Financial Impacts:** Extending Pickering operations would improve OPG's cash flow by $4 Billion in the 2021 to 2024 period compared to the alternative of shutting down in 2020 and assuming that OPG implements a rate smoothing deferral account. Extending Pickering operations also provides incremental net income to OPG.

- **Rate Impacts:** Figure 2 shows the impact of the Preferred Alternative on OPG Nuclear rates. Extending Operations moderates the rate impacts associated with the refurbishment and return to service of the Darlington units and the earlier shutdown of Pickering which would occur in the Base Case. This occurs because extending Pickering Operations results in a larger OPG generation base over which to spread the impacts of the Darlington Refurbishment costs being placed into the rate base and because the severance and related closure costs of Pickering would be deferred.

Figure 2: OPG Nuclear Rate Impacts of Preferred Alternatives



*Note: These rate projections do not yet include finalized assumptions regarding Darlington Refurbishment Costs; however no material change is expected to these rate curves.

- **Severance and Related Costs:** Defers costs associated with closure of the station, such as severance and related costs, and pension curtailment and settlement resulting in a potential reduction in the present value of the severance and related costs. While there is significant uncertainty around these costs the deferral of these costs by 4 years, even if there is no change in the nominal value, would results in present value savings. Demographic changes by the end of Extended Operations could result in a reduction of the estimate of severance costs, potentially resulting in higher estimated Present Value savings.

- **Decommissioning Liability:** Defers expenditures associated with placing the units in the safe-stored state, and the assumed deferral of the expenditures associated with dismantling of the units. The effect is to reduce the liability associated with decommissioning of the Pickering station. This value is considered by the IESO in its assessments.

- **System Economic Value:** For the Ontario system, extended operation of Pickering would mitigate capacity availability uncertainties associated with the refurbishments of the Darlington and Bruce stations. Availability of Pickering would reduce the need to operate gas-fired capacity and would result in reduced CO_2 emissions over the 2021 to 2024 period. OPG's assessment of the median value to the Ontario electricity system of the Preferred Alternative, relative to the Base Case is summarized in Table 7.

Table 7: System Economic Value – Preferred Alternative P1& 4 S/D 2022; P5-8 S/D 2024

Generation Plan	Net Incr. Energy (TWh)	CO_2 Red'n (MT)	Med. System Economic Value (2015$M NPV)	Comments
OPTION 1	65	~18	610	System value is higher because of the assumed higher generation from 2021-2024.
OPTION 2	62	~16	530	

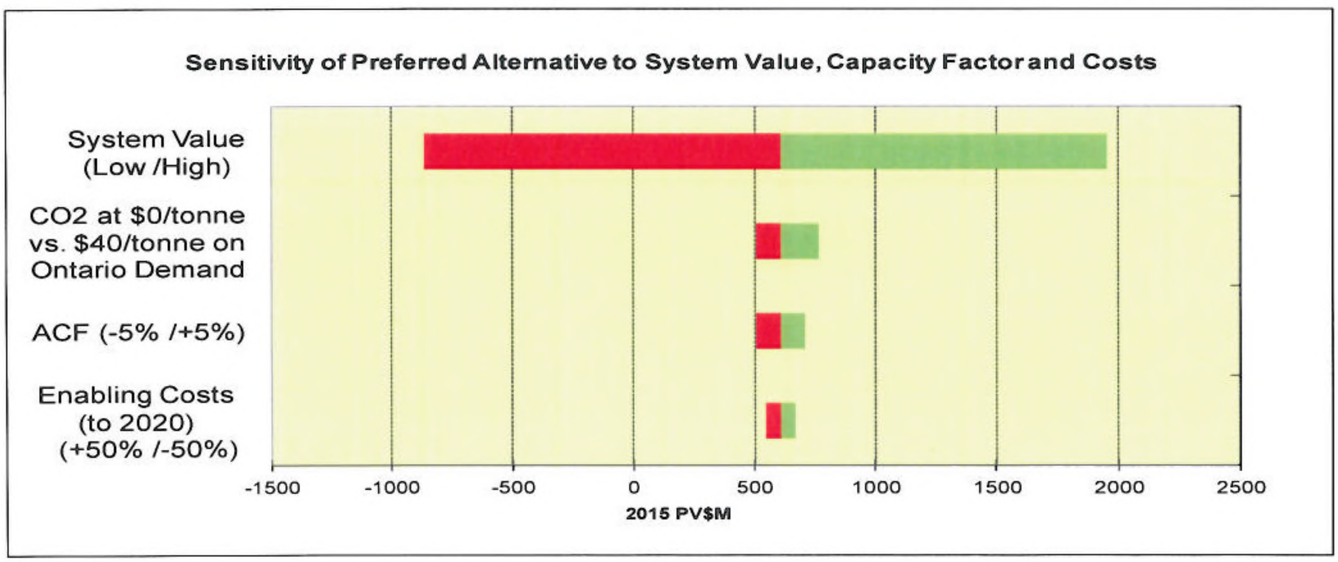
The values in Table 7 include a benefit of $245M (2015 PV$) associated with the reduced present value of severance and related costs. Also includes is a benefit of $100M representing the value of the reduction in the decommissioning liability as a result of the deferral in the decommissioning expenditures.

The IESO has completed an updated assessment using data provided by OPG in October 2015. The assessment shows a benefit ranging from ~$0.3 Billion (2015 PV$) to ~$0.5 Billion (2015 PV$). The IESO's assessment, therefore closely corresponds to OPG's internal assessment. The IESO uses a lower real discount rate (4% vs. OPG's approx. 5%) and different system assumptions (e.g. for load growth and the price of gas-fired generation).

Figure 3 shows the sensitivities of the system economic value for OPTION 1 to uncertainties in the system energy and capacity value, the performance and the incremental costs to enable the Preferred Alternative, and the value of carbon reduction.

The system economic value of the Preferred Alternative is significantly more sensitive to system assumptions than to the costs and performance of Pickering.

Figure 3: Sensitivity of System Economic Value (PLAN 1) to Changes in Assumptions



Ontario Energy Board Act, 1998
Loi de 1998 sur la Commission de l'énergie de l'Ontario

ONTARIO REGULATION 53/05

PAYMENTS UNDER SECTION 78.1 OF THE ACT

Consolidation Period: From January 1, 2016 to the e-Laws currency date.

Last amendment: O. Reg. 353/15.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,
   i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and
   ii. the revenues and costs are accurately recorded in the account.
2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.
3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.
4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Project or 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.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,
   i. the costs were prudently incurred, and
   ii. the financial commitments were prudently made.

Board Staff Interrogatory #93

Issue Number: 6.1
Issue: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities (excluding that for the Darlington Refurbishment Program) appropriate?

Interrogatory

Reference:
Ref: Exh F2-3-3 Attachment 1 Tab 4
This BCS relates to the Fuel Channel Life Extension (FCLE) Project (Project # 10- 80014). The BCS is identical to the BCS previously filed under EB-2013-0321 (Exh F2- 3-3, Attachment 1, Tab 11). The BCS is a partial-release BCS, approved on 2013-11- 11, to fund Phase 1 of the FCLE project during 2014 and 2015. The BCS states that another CANDU operator will co-fund the R&D effort at 50% (page 3).

a) Please provide an update on the project schedule and cost including whether Phase 1 was completed and whether the estimated total project cost, including the non- OPG CANDU operator's share, is still $105.8M including contingency.

b) It is noted that OPG received Canadian Nuclear Safety Commission (CNSC) approval in November 2015 to operate the Darlington units up to the proposed refurbishment outages, to a maximum of 235,000 EFPH (Equivalent Full Power Hours). Please confirm that the idle time (estimated at 57 months) on the last 3 Darlington units to be refurbished (refer to Figure 1 of BCS, page 2) has been eliminated.

c) What is the status of the project's objective and/or confidence level to achieve fuel channel fitness-for-service of at least 261,000 EFPH for Pickering?

Response

a) In the partial release approved on November 11, 2013, OPG estimated the total project cost inclusive of industry shared work to be $105.8M with OPG's costs estimated at $67.4M. OPG's cost of $67.4M can be divided into two distinct scopes of work: OPG-specific work and industry-shared R&D work. The $67.4M estimate was based on best available information and prior to partnership arrangements being finalized for the shared scope of work.

OPG's current best estimate of the total project cost (inclusive of industry shared work) is $97M (including contingency), with OPG's share being $69.3M (see L-6.1-1 Staff-93 Attachment 1 which includes confidential content as marked). This revised total project cost does not include industry partner internal costs, which are not available to OPG.

As noted, a component of OPG’s share of $69.3M includes industry shared R&D work. Partnership agreements are now in place for the industry-shared scope of R&D work and OPG’s share for this portion of work is 47.5%.

Significant testing has been completed with respect to Burst Tests, pressure tube fracture toughness testing, material property testing of pressure tubes, fatigue crack initiation testing, crush and fatigue testing of Darlington spacers etc. Phase I work is scheduled to be completed in 2017 with project completion expected in 2020.

b) Confirmed. The idle time that was estimated on the last three Darlington units to be refurbished (see L-6.1-1 Staff-93 Attachment 1, p. 2, Figure 1) has been eliminated.

c) OPG is highly confident of continued safe operation of Pickering fuel channels for operation to the target service life of December 2020 based on its ongoing assessment of fuel channel fitness for service and interactions with CNSC staff.

Board Staff Interrogatory #123

Issue Number: 6.5
Issue: Are the test period expenditures related to extended operations for Pickering appropriate?

Below are interrogatories on the IESO's analysis (Exh F2-2-3 Attachment 1) of Pickering Extended Operations. In order to provide complete responses to all OEB staff interrogatories please consult the IESO as necessary.

Interrogatory

Reference:
Ref: Exh F2-2-3 Attachment 1, EB-2013-0321

a) In developing the business case to assess the feasibility of operating Pickering from 2016 to 2020, OPG relied on certain assumptions with respect to the Normal operating and capital costs for Pickering for the period 2016 to 2020 and concluded that there was $520M overall system benefit. In table format, please provide separately the assumptions for capital and operating cost relied on in assessing the feasibility of Pickering operations to 2020 and also referenced in the 2012 Business Case Update - Pickering Continued Operations (EB-2013-0321/ F2-2-3-Attachment 1), for each of the years 2016-2020. On a similar and comparable basis please provide the forecast of operating (including all compensation and corporate burdens) and capital costs related to Pickering operations in the current application for the years 2016-2020.

b) Please calculate the variance between the Business Case assumptions and the Test Year forest for each of years 2016-2020. Please comment on the variance in the context of:
   i. The observations in the 2012 Business Case Update which state: "The expected value is somewhat sensitive to the total cost of operating the Pickering Station. ....if OM&A costs were to worsen by 10%, then the incremental value would be reduced by approximately $220 M PV."
   ii. The IESO's analysis, which concludes that PEO "shows a disbenefit when Pickering capital/operating costs are 15-22% greater than the estimates provided by OPG"

Response

a) In order to derive the comparison requested in part a) OPG used the cost and generation assumptions developed in the business case for Continued Operations from EB-2013-0321, Ex. F2-2-3 Attachment 1 and compared them to the reference scenario used for the current Extended Operations that assumes all Pickering units cease commercial operations at the end of 2020. All costs were converted to 2015$ for comparison purposes.

The analysis indicates that current costs under the reference scenario are approximately \$195M higher than previously projected. This figure is offset by fuel costs that are between \$20M and \$27M lower depending on the assumed production as shown in the comparison below. The majority of the variance occurs in 2020 where under the current reference scenario, all Pickering units are expected to operate to year end 2020. Whereas under the original Continued Operations plan, the following end of life dates were expected based on 247k EFPH of operation on the fuel channels;

- Unit P6 - April 2019,
- Unit P5 - February 2020 and
- Units P1, P2, P7, and P8 to the end of 2020.

The extended service life under the current scenario generates between 6.2 TWh and 6.8 TWh of production in 2020 and would effectively require a full staff compliment to support plant operations for an entire year resulting in higher operating costs beginning in 2019 and continuing through 2020.

COMPARISON OF PICKERING OPERATING COSTS 2016-2020

2015 Ext. Operations Reference Case versus 2012 Continued Operations Case

	2016	2017	2018	2019	2020	**Total**
PICKERING CONTINUED OPERATIONS - 247k EFPH (Units 1, 4, 7 & 8 Operate to Q4 2020, Unit 6 Operates to Q2 2019 and Unit 5 Operates to Q1 2020)						
Total OM&A & Capital Costs (2015 $M)	1,001	953	965	891	624	**4,433**
Fuel & Fuel Related Costs (2015 $M)	125	143	121	117	99	**605**
Energy Production (TWh)	21.0	22.6	21.9	20.3	17.2	**103.1**

PICKERING EXTENDED OPERATIONS Reference Case - 259k EFPH (All PNGS Units Operate to Year End 2020)						
BCS Option 1 (Incr. 65 TWh Scenario)						
Total OM&A & Capital Costs (2015 $M)	1,048	953	959	909	759	**4,628**
Fuel & Fuel Related Costs (2015 $M)	120	114	111	113	128	**585**
Energy Production (TWh)	20.8	20.0	20.4	21.2	24.1	**106.5**
BCS Option 2 (Incr. 62 TWh Scenario)						
Total OM&A & Capital Costs (2015 $M)	1,048	953	959	909	759	**4,628**
Fuel & Fuel Related Costs (2015 $M)	120	114	111	109	124	**578**
Energy Production (TWh)	20.8	20.0	20.4	20.5	23.4	**105.2**

Comparison - Continued Operations to 2020 vs. Extended Operations (Reference Scenario)

BCS Option 1 (Incr. 65 TWh Scenario)						
Total OM&A & Capital Costs (2015 $M)	48	0	-6	18	135	**195**
Fuel & Fuel Related Costs (2015 $M)	-5	-30	-10	-4	29	**-20**
Energy Production (TWh)	-0.2	-2.6	-1.5	0.9	6.8	**3.5**
BCS Option 2 (Incr. 62 TWh Scenario)						
Total OM&A & Capital Costs (2015 $M)	48	0	-6	18	135	**195**
Fuel & Fuel Related Costs (2015 $M)	-5	-30	-10	-8	26	**-27**
Energy Production (TWh)	-0.2	-2.6	-1.5	0.2	6.2	**2.1**

b) The 10% sensitivity analysis described in EB-2013-0321 Ex. F2-2-3 Attachment 1 is based on Pickering's total incremental annual capital and operating cost. The total operating cost delta of $168M (using the 6.2 TWh production figure) represents a variance of less than 4% assuming all things equal. As described in part a) of this response, however, the majority of the variance occurs in 2020 when between 6.2 TWh and 6.8 TWh of incremental generation is also expected to be achieved.

UNDERTAKING JT1.17
ATTACHMENT M

Undertaking

ED INTERROGATORY #33

This interrogatory requested a comparison of Pickering Extended Operations versus a shutdown in August 31, 2018. No response was provided. Please provide a response. August 31, 2018 is a highly relevant date for comparison purposes. Pickering cannot be shut down before that date, which is when the Clarington Transformer Station will be built. But after that date, Pickering is just one of a number of options to meet Ontario's electricity supply. At that point, OPG should not be paid more for the power from Pickering than the cheapest alternative, which could be considered to be the "market rate." After that date it is important to know what the lowest cost alternative is. Environmental Defence would argue that OPG should not be paid any more than the lowest cost alternative.

Response

OPG declines to respond to this request on the basis of relevance. The comparison requested is not relevant to the issue before the OEB, which is the establishment of payment amounts for OPG and not whether Pickering should continue to operate (see references in Undertaking Response JT1.17n). Furthermore, as Mr. Blazanin explained during the technical conference: "The CNSC board has already approved operation of Pickering to 247,000 effective full power hours on our fuel channels, which is the life limiting major component. That would take most units into the 2020 time frame already." (Technical Conference Transcript V. 2, page 82, lines 20-24). Thus as a practical matter, there is no basis for assuming an August 31, 2018 shut-down date as requested in the interrogatory.

Board Staff Interrogatory #134

Issue Number: 6.5
Issue: Are the test period expenditures related to extended operations for Pickering appropriate?

Below are interrogatories on the IESO's analysis (Exh F2-2-3 Attachment 1) of Pickering Extended Operations. In order to provide complete responses to all OEB staff interrogatories please consult the IESO as necessary.

Interrogatory

Reference:
Ref: Exh F2-2-3 Attachment 1 page 73

In the 2013 Long-Term Energy Plan (LTEP) it is noted that early shutdown of Pickering units may be possible if the Clarington transformer station can be placed in service by 2018. Given that the Clarington transformer station is expected to be in-service by 2018 (page73) please describe what has changed, specifically with respect to capacity and demand needs in the East-GTA region, since the release of 2013 LTEP that makes the case for extended operations necessary.

Response

The following response has been prepared by the IESO:

As indicated at Exh F2-2-3 Attachment 1 page 73, the transmission plan for East GTA includes the construction of a new 500/230 kV transformer station in Clarington to maintain supply reliability to Durham Region following Pickering shutdown and to provide a secure electricity supply in this high growth area. Hydro One is currently constructing the new transformer station ("Clarington TS") and remains on schedule for an in-service of 2018.

The IESO's evaluation of Pickering options assumes a 2018 in-service date for Clarington TS (i.e. under all Pickering shut-down scenarios assessed). Contrary to the premise of the question, the IESO's analysis does not posit that capacity and demand needs in the East-GTA make the case for extended operations necessary.

Rather, the IESO identifies a variety of potential benefits of extended Pickering operations, including reductions in replacement capacity costs and reductions in replacement energy costs from gas-fired resources and energy imports.

ED Interrogatory #33

Issue Number: 6.5
Issue: Are the test period expenditures related to extended operations for Pickering appropriate?

Interrogatory

Reference:
Reference: "Pickering extension to 2022/2024 yields a net benefit in the range of $0.3B-$0.6B…" Exhibit F2-2-3, Attachment 1, Page 6 of 116

Please compare the option of Pickering GS shutting down on August 31, 2018 versus OPG's plan to operate it until 2022/2024 by providing a forecast for each relevant year of:

a) Ontario's surplus base-load generation (MWh) due to Pickering's continued operation after August 31, 2018;

b) Ontario's curtailed water power generation (MWh) due to Pickering's continued operation after August 31, 2018;

c) Ontario's curtailed wind power generation (MWh) due to Pickering's continued operation after August 31, 2018;

d) Ontario's curtailed solar power generation (MWh) due to Pickering's continued operation after August 31, 2018;

e) Ontario's total revenue from its surplus base-load generation due to Pickering's continued operation after August 31, 2018;

f) The cost to Ontario's electricity consumers of Ontario's curtailed water power generation due to Pickering's continued operation after August 31, 2018;

g) The cost to Ontario's electricity consumers of Ontario's curtailed wind power generation due to Pickering's continued operation after August 31, 2018;

h) The cost to Ontario's electricity consumers of Ontario's curtailed solar power generation due to Pickering's continued operation after August 31, 2018; and

i) The total cost to Ontario's electricity consumers of all power that must be curtailed due to Pickering's continued operation after August 31, 2018.

Please provide a response on a best-efforts basis and make and state assumptions as necessary.

Response

The following response has been prepared by the IESO:

The scope of the IESO's assessment of Pickering extended operations referred to in Exhibit F2-2-3, Attachment 1, Page 6 of 116 (the "October 2015 study") was with respect to Pickering retirement at the end of 2020 versus extended operations to 2022/2024. The IESO did not evaluate extended operations relative to shutting Pickering down on August 31, 2018 in the October 2015 study. However, the March 2015 study included an assessment of surplus energy and net benefit relative to Pickering shutdown in 2018. This is illustrated in pages 42 through 116 of Exhibit F2-2-3 Attachment 1. Specifically, surplus energy is illustrated on page 53. Net benefit relative to shutting down in 2018 is summarized on page 61.

UNDERTAKING JT1.17
ATTACHMENT P

Undertaking

ED INTERROGATORY #39

This interrogatory requested a comparison of the net benefits of continuing to operate Pickering until 2022/2024 versus a Pickering shutdown in August 31, 2018, with replacement power to come from a combination of the lowest cost options including the maximum possible electricity imports from Quebec. This was not done. The IESO stated that hydro power from Quebec cannot fully replace Pickering and that the IESO's analysis is already based on "the next least-cost alternative." However, the IESO's analysis is based on obtaining all the power from one source – gas fired generation, rather than a combination of lowest cost sources including increased power imports. Please provide a response based on a combination of the lower cost sources.

Please also assume that replacement electricity is not needed to replace electricity that would be exported (i.e. replacement power is only required to meet Ontario's actual needs).

Response

OPG declines to respond to this request on the basis of relevance. As explained in JT1.17(n), the purpose of this proceeding is not to consider system planning or to determine whether Pickering should continue to operate. Furthermore, as noted in JT1.17(m), as a practical matter, there is no basis for assuming an August 31, 2018 shut-down date.

UNDERTAKING JT1.17
ATTACHMENT N

Undertaking

ED INTERROGATORY #35

Please answer this interrogatory. The IESO states that its contingency planning is still ongoing, but that is not a reason for not providing its best possible answers to our questions now.

Response

OPG declines to respond to this request on the basis of relevance. As the IR answer indicates, the requested information is not available because the IESO is in the process of developing it. Moreover, the requested information is not relevant to deciding the issue before the OEB regarding the cost of Pickering Extended Operation. As the OEB has recognized in several prior decisions, the purpose of this proceeding is to establish payment amounts and not to decide system planning issues or determine whether specific generation facilities should continue to operate.[1]

[1] See EB-2007-0905, Decision with Reasons, page 28; EB-2010-008, Decision with Reasons, page 51; EB-2013,-0321 Decision on Issues List, June 4, 2014, page 3 “The Board agrees with OPG that generation planning is not within the scope of this proceeding.”

UNDERTAKING JT1.17
ATTACHMENT L

Undertaking

ED INTERROGATORY #30
This interrogatory requested that the IESO recalculate its cost-benefit analysis of Pickering Extended Operations based on its best *current* estimates of the key variables listed in the interrogatory. The IESO stated that it has not updated its assessment. That is not a justification for not doing so. The requested information is highly relevant. We ask that the requested information be provided.

Response

OPG declines to respond to this request on the basis of relevance. In its Decision in EB-2013-0321 approving expenditures for Pickering Continued Operations, the OEB discussed the fact that the OPA found that project to have positive benefits (see page 51). On this basis, OPG determined that the OEB and the parties could find the IESO's analysis similarly helpful in reviewing the costs of Pickering Extended Operations and included both the IESO's initial (March 9, 2015) and follow-up (November 4, 2015) analyses as an attachment to OPG's evidence (Ex. F2-2-3, Attachment 1). As the IESO has indicated that it has not performed any subsequent analysis, there is nothing more to produce. The fact that Environmental Defence would like the IESO to perform further updates does not make this information necessary or relevant to the OEB's consideration of the costs to extend Pickering Operations.

ED Interrogatory #40

Issue Number: 6.5
Issue: Are the test period expenditures related to extended operations for Pickering appropriate?

Interrogatory

Reference:
Reference: Ex. F2-2-3, Attachment 1

The September 2016 Mandate Letter to the Minister of Energy asks that he "Continue to partner and collaborate with the Province of Québec on key energy issues, including … In co-operation with the IESO and Hydro-Québec, further the intention to explore an electricity trade agreement that would provide value to Ontario ratepayers."

Please provide a breakdown of the transmission upgrade projects that would be necessary to replace the power from Pickering with imports from Quebec. Please indicate an approximate cost for each project and an estimate of the amount of time it would take for the project to be completed.

Response

The following response has been prepared by the IESO:

Pickering Nuclear has a nameplate capacity of approximately 3,300 MW. The transmission upgrades necessary to allow a firm capacity of 3,300 MW to flow from Québec are outlined in "Review of Ontario Interties" report written by IESO and OPA, and published on October 14, 2014. From the report, the necessary upgrades to the Ontario system are as follows:

1. Upgrading the 230 kV circuits between Merivale TS and Hawthorne TS. This is also needed to serve local load growth. The upgrades will cost approximately $325 million and estimated to take three to five years.

2. A new 230 kV double-circuit line between Cornwall and Ottawa to replace the existing single-circuit 115 kV line along the right of way

3. A new 230 kV circuit, approximately 8 km in length to connect existing circuits west of Ottawa (Kanata).

4. Additional voltage control equipment in the Ottawa area.

   Cost of 2-4 is approximately $500 million and would take five to seven years

5. A new double-circuit 230 kV interconnection with Québec with a new back-to-back DC facility at the Québec-Ontario border.

6. A Replacement of the existing phase-angle regulating transformers on the interties to New York at Cornwall, with units having a greater regulating range to control flows into and out of New York.

7. A new 46 km 500 kV double-circuit line between the Bowmanville and Cherrywood transformer stations

   The cost of 5-7 could be as high as $1.4 billion. Including the time needed for regulatory and environmental approvals, the time needed to complete these enhancements is estimated to be seven to 10 years.

To complete all necessary upgrades the total cost is in excess of $2 billion with an estimated seven to ten years lead time.

An important consideration beyond just the cost of transmission upgrades in Ontario would be the system upgrades necessary in Québec and subsequently their cost of delivering the capacity to the border. Public documents indicate that Québec currently has limited quantities of capacity available to export in the winter and intends to add capacity in the coming years; please refer to: "ÉTAT D'AVANCEMENT 2015 DU PLAN D'APPROVISIONNEMENT 2014-2023." Consequently, any deal to supply baseload energy year round, similar to Ontario's nuclear plants, would require the construction of new generation in Quebec. This new generation would be more expensive than existing power because it would factor in the cost associated with new generation and transmission build, resulting in higher import prices for Ontario.

UNDERTAKING JT2.4

Undertaking

TO RECONCILE ED 18, BOARD STAFF 116, AND GEC 38, AND ADVISE THE DIFFERENCES WHAT COSTS WERE INCLUDED OR EXCLUDED AS BETWEEN THE THREE.

Response

The numbers used in the three referenced documents are different because they were produced to respond to specific questions from the requesting parties. However, they are consistent and are reconciled below.

Exhibit L-6.5-1 Staff-116 (Staff-116) provides the values for the variables in Chart 1 at Ex. F2-2-3. Chart 1 at Ex. F2-2-3 shows the estimated operating costs to enable Extended Operations and operate Pickering in each year of the IR Term as proposed to be recovered in the revenue requirement. These costs include OM&A expenses and capital costs, but exclude fuel costs. As shown in Staff-116, the total planned fully allocated operating costs for Pickering are $1,395M in 2021.

Exhibit L-6.5-8 GEC-38 (GEC-38) asks for Pickering's "total allocated operating costs." As this term is not precisely defined, OPG responded based on a standard industry definition. OPG benchmarks its financial performance against other utilities based on industry accepted (EUCG) metrics including Total Generating Cost (TGC) per MWh. GEC 38 (and by reference Ex. L-6.2-15 SEC-063) provides a derivation of TGC per MWh, and shows the 2021 TGC as $1,526.9M. As established by EUCG, TGC includes Base OM&A, Outage OM&A, Project OM&A, Corporate Support & Administrative costs, component of centrally held costs (excluding OPEB and Pension amounts and IESO Non-energy Charges as noted in Ex. L-6.2-1 Staff-104), fuel costs, and capital costs.

As shown in the reconciliation provided in Chart 1 in GEC-38, OPG started with the total planned operating costs in Staff 116 and made necessary adjustments to arrive at the TGC. Specifically, OPG made the following adjustments:

<u>Additions:</u>

- Fuel costs: TGC includes fuel costs. As noted above, Chart 1 at Ex. F2-2-3 and therefore L-6.5-1 Staff 116 excluded fuel costs (although fuel costs are included in the Business Case Summary supporting Extended Operations at Attachment 2 to that exhibit, as indicated in Ex. L-6.5-1 Staff-118 (b)).
- Pickering portion of Tritium Removal Facility: TGC includes these costs but for purposes of Chart 1 at Ex. F2-2-3 and therefore L-6.5-1 Staff 116, these costs were excluded for the reasons discussed at JT2.05.
- Inventory Obsolescence: TGC includes inventory obsolescence costs but for purposes of Chart 1 at Ex. F2-2-3 and therefore L-6.5-1 Staff 116, these costs were excluded for the reasons discussed at JT2.05

<u>Subtraction:</u>

- Asset User (Service) Fee: These costs are excluded from the TGC per industry standards but are included for purposes of Chart 1 at Ex. F2-2-3.

Exhibit L-6.5-7 ED-18 (ED-18) asked OPG to confirm Environmental Defense's calculations of Pickering Nuclear Station's operating and fuel costs for 2017, 2018, 2019 and 2020 broken out by sixteen components. OPG noted in its response to ED-18, that Environmental Defence's methodology for allocating costs is inconsistent with OPG's approved allocation methodology (see Ex. F3-1-1) and that certain of the sixteen components such as depreciation, property tax and income tax are not classified as "OM&A," which is why OPG excludes those cost elements from its calculation of total operating costs.

As per GEC-38, TGC in 2021 is $1,526.9M. Chart 1 in ED-18 establishes in the first subtotal an amount of $1,537.6M in 2021. The TGC in 2021 can be reconciled to the $1,537.6M by subtracting the asset service fee of $10.7M (rounded to $11M in Chart 1 of GEC-38), which is excluded from TGC, but included within Environmental Defense's sixteen cost components.

In preparing this undertaking, OPG noted that there is an inadvertent spreadsheet error in Chart 1 in ED-18 for the year 2021. The amount of -$22.7M in the line item designated "Other" was not deducted in the spreadsheet totals. As a result, the $1,654.0M grand total for 2021 should be revised to $1,631.4M. A revised Chart 1 is included below.

The remaining difference between the $1,526.9M in GEC-38 and the $1,631.4M grand total in Chart 1 below is explained by the removal of capital costs of $23.1M, as well as the exclusion of various non-operating cost components listed in the chart below the second subtotal for the reasons set out in JT2.5.

	Pickering Costs							
($M, unless otherwise stated)	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Total Operating Costs - Initial	**1,319.4**	**1,347.2**	**1,364.0**	**1,351.4**	**1,351.4**	**1,391.7**	**1,337.9**	**1394.5**
Add								
Inventory Obsolescence[1]	0.0	0.0	12.4	12.4	12.4	12.4	12.4	12.4
Pickering portion of Tritium Removal Facility[1]	0.0	0.0	10.4	11.2	11.6	10.9	12.2	12.8
Fuel Costs	113.5	120.4	120.2	114.4	115.5	116.5	120.5	117.9
Subtotal	**1,432.9**	**1,467.6**	**1,507.0**	**1,489.4**	**1,490.9**	**1,531.5**	**1,483.0**	**1537.6**
Less								
Capital	119.5	90.9	124.3	85.2	29.8	28.0	23.2	23.1
Subtotal	**1,313.4**	**1,376.7**	**1,382.7**	**1,404.2**	**1,461.1**	**1,503.5**	**1,459.8**	**1514.5**
Add								
OPEB and Pension excluded from Centrally Held Costs	10.7	45.8	48.5	62.7	39.2	25.5	15.7	10.0
IESO Non energy Charges[2]	32.2	51.5	27.6	30.6	28.2	25.7	28.7	22.3
Other[1]	0.0	0.0	-3.7	-68.6	-37.3	-25.8	-30.6	-22.7
Subtotal	**1,356.3**	**1,474.0**	**1,455.1**	**1,428.8**	**1,491.2**	**1,529.0**	**1,473.5**	**1,524.2**
Add								
Depreciation and Amortization _Pickering[2]	140.9	147.3	165.7	199.9	223.2	226.7	233.3	53.1
Depreciation and Amortization- Pickering Generic[2]	44.2	53.5	34.2	38.6	37.1	34.9	36.7	20.4
Income Tax - Pickering[2]	-25.7	-15.2	-8.3	-9.2	-9.2	-9.1	26.9	27.5
Property Tax- Pickering	4.9	4.9	5.0	5.4	5.5	5.7	5.8	6.3
Total								
Planned Operating Costs	**1,520.5**	**1,664.5**	**1,651.7**	**1,663.6**	**1,747.9**	**1,787.2**	**1,776.2**	**1631.4**
Pickering Generation - TWh	**20.1**	**21.2**	**20.8**	**19.1**	**19.2**	**19.4**	**19.6**	**18.8**
Planned Operating Costs- $/MWh	**75.7**	**78.4**	**79.5**	**87.3**	**91.1**	**92.3**	**90.5**	**86.7**

[1] Included in Total Operating Costs- Initial in 2014 actual and 2015 actual
[2] Allocation based on Pickering % of generation

UNDERTAKING JT1.17
ATTACHMENT G

Undertaking

ED INTERROGATORY #28

1. With respect to the first 3 columns in (b) why does Pickering's estimated available capacity in 2020 (3094 MW) equal its installed capacity? That is, why does the IESO assume that the expected forced outage rate is zero? For each column and each year, please state the impact in MW of the expected forced outage rate on Pickering's available capacity at the time of the system peak.

2. With respect to the response to (d), please also quantify the impact of Pickering's extended operation on imports & exports for each year (another form of avoided generation).

3. With respect to sub-question (e), the IESO has misinterpreted ED's question. ED is not seeking Pickering's actual forced outage rate in 2014, but rather the forced outrage rates that the IESO assumed for Pickering when forecasting how much of its capacity would be available at the time of Ontario's system peak for each year of its analysis. Please ask the IESO to provide this information.

Response

The following response has been prepared by the IESO.

1. The Pickering capacity that is available at the time of peak demand is assumed to be the installed capacity, provided that it is not on planned outage or forced outage or in a derated state. The forced outage rate is accounted for within the reserve margin as well as in power system production simulation analysis.

2. Please see table below for the impact of Pickering extended operation on electricity imports and exports.

	Change in Energy (GWh)			
	Case with +65 TWh of Pickering Production		Case with +62 TWh of Pickering Production	
	Imports	Exports	Imports	Exports
2015	0	0	0	0
2016	0	0	0	0
2017	237	-271	237	-271
2018	264	-665	234	-637
2019	324	-932	335	-816
2020	687	-1,740	854	-1,982
2021	-6,596	5,961	-6,447	5,706
2022	-6,610	8,035	-6,392	7,625
2023	-4,667	5,332	-4,400	4,984
2024	-4,851	7,458	-4,708	7,248

3. The IESO accounted for both forced and planned outages in its analysis. The tables below summarize forced outage and planned outage rates used.

For the case with +65 Twh of Pickering Production with the extension

Pickering to 2020

Forced Outages	2016	2017	2018	2019	2020	2021	2022	2023	2024
P1 & P4	7.0%	7.0%	7.1%	7.1%	7.2%	n/a	n/a	n/a	n/a
P5 - P8	4.0%	4.0%	4.0%	4.0%	4.0%	n/a	n/a	n/a	n/a

Planned Outages (Days)	2016	2017	2018	2019	2020	2021	2022	2023	2024
P1	34	143	69	119	43	n/a	n/a	n/a	n/a
P4	108	57	121	-	40	n/a	n/a	n/a	n/a
P5	-	145	-	109	-	n/a	n/a	n/a	n/a
P6	-	121	-	131	-	n/a	n/a	n/a	n/a
P7	118	-	122	-	-	n/a	n/a	n/a	n/a
P8	143	-	117	-	40	n/a	n/a	n/a	n/a

Pickering to 2022/2024

	2016	2017	2018	2019	2020	2021	2022	2023	2024
P1 & P4	7.0%	7.0%	7.1%	7.1%	7.2%	7.2%	7.2%	n/a	n/a
P5 - P8	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.5%	5.0%

Planned Outages (Days)	2016	2017	2018	2019	2020	2021	2022	2023	2024
P1	34	192	43	129	43	97	43	-	-
P4	108	43	131	-	111	34	42	-	-
P5	-	148	-	182	-	147	-	101	-
P6	-	158	-	207	-	151	-	99	-
P7	118	-	221	-	106	34	140	-	-
P8	143	-	137	-	157	34	141	-	40

Filed: 2008-04-09
EB-2007-0905
Exhibit L
Tab 1
Schedule 1

For the case with +62 Twh of Pickering Production with the extension

Pickering to 2020

Forced Outages	2016	2017	2018	2019	2020	2021	2022	2023	2024
P1 & P4	7.0%	7.0%	7.1%	7.1%	7.2%	n/a	n/a	n/a	n/a
P5 - P8	4.0%	4.0%	4.0%	4.0%	4.0%	n/a	n/a	n/a	n/a

1

Planned Outages (Days)	2016	2017	2018	2019	2020	2021	2022	2023	2024
P1	34	143	69	119	43	n/a	n/a	n/a	n/a
P4	108	57	121	63	69	n/a	n/a	n/a	n/a
P5	-	145	-	109	-	n/a	n/a	n/a	n/a
P6	-	121	-	131	-	n/a	n/a	n/a	n/a
P7	118	-	122	-	-	n/a	n/a	n/a	n/a
P8	143	-	117	-	40	n/a	n/a	n/a	n/a

2

Pickering to 2022/2024

	2016	2017	2018	2019	2020	2021	2022	2023	2024
P1 & P4	7.0%	7.0%	7.1%	7.1%	7.2%	7.2%	7.2%	n/a	n/a
P5 - P8	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.5%	5.0%

3

4

Planned Outages (Days)	2016	2017	2018	2019	2020	2021	2022	2023	2024
P1	34	192	43	128	43	138	43	-	-
P4	108	43	130	43	153	30	83	-	-
P5	-	148	-	182	-	168	-	135	-
P6	-	158	-	207	-	167	-	134	-
P7	118	-	221	-	127	30	160	-	-
P8	143	-	137	-	177	30	161	-	75

5

4. As a starting point, the IESO adopted OPG's cost estimates in the IESO assessment of Pickering extended operations. The IESO subsequently considered the potential for higher costs/lower Pickering performance by way of sensitivity analysis.

UNDERTAKING JT1.17
ATTACHMENT H

Undertaking

ED INTERROGATORY #29

1. With respect to response (b), for each year please state how much of the difference in MWs between Pickering's "installed" and "available capacity" is due to expected forced outages.

2. Part (d) requested the avoided generation that the IESO estimates would be caused by Pickering operating to 2022/2024. The IESO stated as follows: "Not applicable, as the simulation run of Pickering operates to 2020 is not available." This response does not explain why a response could not be calculated or provided. Please provide a response to that part of the interrogatory.

3. Part (e) requested the IESO's *current* forecast of the Pickering forced outage rate from 2016 to 2024. The reference provided in response does not include that information. Please provide the requested information.

4. No response was provided to part (f). Please provide a response.

5. No response was provided to part (l). Please provide a response. This is relevant. If Ontario's incremental peaking requirements, assuming Pickering is not extended, have changed, then this will impact the economics of the proposed Pickering extension. Whether or not a Pickering simulation is available, the IESO will have up-to-date estimates of our incremental capacity requirements if Pickering is not extended.

6. No response was provided to part (m). Please provide a response. The IESO analysis has assumed that the cost of the replacement capacity is equal to the cost of building new gasfired peaker plants. But it is highly relevant to know if there are lower cost options to meet our capacity needs.

7. The last line of the interrogatory asked that the IESO "please state your methodology for calculating Pickering's available capacity (MW) at the time of Ontario's peak demand." No response was provided to this part of the interrogatory. Please provide a response.

Response

The following response has been prepared by the IESO. OPG has inserted evidence references in square brackets.

1. As indicated earlier in ED IR #28 [Ex. JT1.17(g)] part 1, the Pickering capacity that is available at the time of peak demand is assumed to be the installed capacity, provided that it is not on planned outage or forced outage or in a derated state. The forced outage rate is accounted for, however, and influences the size of the required

reserve margin. The forced outage rate is also accounted for in production simulation analysis.

2. The change in generation production as a result of Pickering Extended Operations is summarized in the tables below.

The following table summarizes the avoided generation (MWh) by fuel type as a result of Pickering's extended operation in the plus 65 TWh of Pickering Production case. Blue and positive numbers represent increase in production and red and negative numbers represent decrease in production as a result of Pickering's extended operation.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Gas	0	0	332,680	274,744	470,923	456,172	-6,756,544	-6,473,855	-4,730,629	-4,167,951
Hydroelectric	0	0	19,589	61,943	99,731	303,070	-373,796	-183,024	-106,101	-228,202
Wind	0	0	30,636	19,706	21,952	213,356	-42,286	0	0	-11,202

The following table summarizes the avoided generation (MWh) by fuel type as a result of Pickering's extended operation in the plus 62 TWh of Pickering Production case. Blue and positive numbers represent increase in production and red and negative numbers represent decrease in production as a result of Pickering's extended operation.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Gas	0	0	332,680	209,640	351,228	763,473	-6,424,056	-6,111,821	-4,473,760	-4,108,400
Hydroelectric	0	0	19,589	61,943	83,710	287,308	-357,001	-182,338	-99,313	-219,580
Wind	0	0	30,636	19,706	16,050	140,642	-28,515	0	0	-11,202

Please see response to ED IR #28 [Ex. JT1.17(g)] part 2 for the impact of Pickering extended operation on electricity imports and exports.

3. Forced outage and planned outage rates assumed in the IESO study are summarized in the response to ED IR #28 [Ex. JT1.17(g)] part 3.

4. See response to part 7 of this interrogatory [Ex. JT1.17(g)].

5. The replacement capacity assumed is assumed to be equivalent to the change in capacity requirements between Pickering operation to 2020 and 2022/2024. These are summarized in the table below.

	Increase in Capacity Requirements Pickering to 2020 relative to 2022/2024 (MW)
2015	0
2016	0
2017	0
2018	0
2019	0
2020	0
2021	2,316
2022	2,301
2023	2,064
2024	1,090

100% of this capacity was assumed to be replaced. This represents the capacity that would need to be replaced to meet NPCC resource adequacy criteria.

6. The cost of replacement capacity is benchmarked to be that of a new-build SCGT at $130/kW-yr. Gas is used as a proxy resource here. This would be the benchmark price for other resources such as demand response or firm capcity imports.

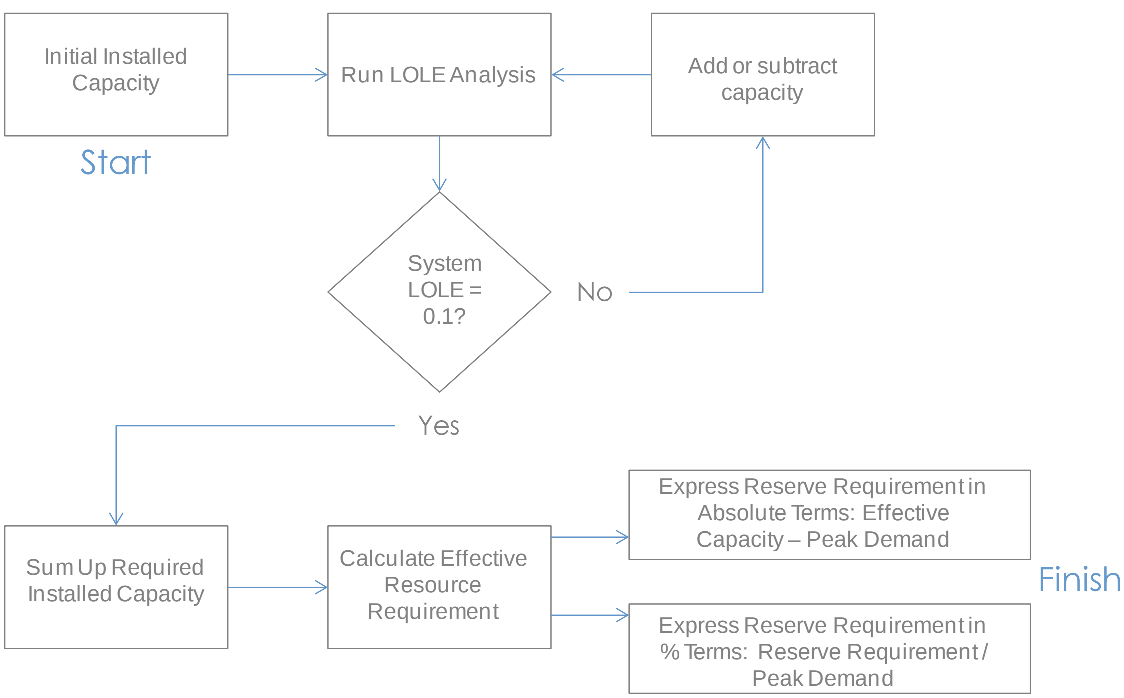
7. The "capacity contribution" or "effective capacity" of a supply resource is an approximation of its power output capability during peak demand periods and can be expressed as a percentage of a resource's installed capacity. Capacity contributions vary among resource types and can be estimated through a variety of methods.

   For planning purposes, the IESO estimates the capacity contributions through a variety of approaches, including by incorporating values submitted to the IESO by electricity generators, analyzing historical generator performance and using statistical methods to assess resource contributions during various percentiles of peak demand or other hours.

   Data and methods used to estimate capacity contributions evolve over time as more data is acquired and as methodological improvements are made. The following table provides indicative overall values, which in practice differ by generator, location and season. More information about these values is available at the Ontario Planning Outlook at http://www.ieso.ca/Pages/Ontario's-Power-System/Ontario-Planning-Outlook/default.aspx:

	Indicative Capacity Contribution (% of Installed Capacity Available at Time of Peak Demand)	
	At Summer Peak	At Winter Peak
Nuclear	99%	90%
Natural Gas	89%	95%
Waterpower	71%	75%
Bioenergy	89%	89%
Wind	11%	28%
Solar PV	33%	5%
Demand Response	83%	66%

Capacity contribution estimates are used in two main ways: they are part of the iterative loss of load expectation and resource requirement assessment process shown in the schematic below and they are used in a variety of supply-demand balance visualizations to allow for approximate but efficient portrayal.



Board Staff Interrogatory #10

Issue Number: 3.1
Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:
Ref: Exh C1-1-1, Chart 1

Chart 1, from page 1 of Exh C1-1-1, is replicated below.

Rate Base	2017	2018	2019	2020	2021
Hydro ($B)[1]	7.5	7.5	7.5	7.6	7.7
Nuclear ($B)[2]	3.3	3.5	3.5	7.5	8.0
Total ($B)	10.8	11.0	10.9	15.1	15.6
Nuclear Proportion	31%	32%	32%	50%	51%

1. Reflects OPG's 2016-2018 Business Plan, which includes a projection for 2019-2021 (Ex. A2-2-1 Attachment 1).
2. From Ex. I1-1-1, Table 1, sum of line 5, line 6 and line 7. Nuclear amounts do not include the lesser of unamortized asset retirement costs ("ARC") or unfunded nuclear liabilities ("UNL"). This is consistent with the OEB-approved methodology for determining rate base financed by capital structure, wherein the weighted average cost of capital is applied to OPG's rate base that does not include the lesser of ARC or UNL.

a) Please confirm whether the rate base values shown are: i) beginning of year; ii) mid-year or average of the year; or iii) end-of year.

b) OPG proposes that the equity thickness for the combined hydroelectric and nuclear generating regulated assets be increased to 49% for the whole period of the five- year term, in light of increased risk. The significant capital additions are mainly due to the Darlington Refurbishment Program, which significantly increases the relative percentage of OPG's regulated asset rate base related to nuclear generation. However, from Chart 1, significant additions to the nuclear rate base only begin to occur in 2020, when the nuclear rate base becomes approximately equal to the hydroelectric rate base, and exceeds it only in the last year of the plan 2021. For the first three years of the plan (2017-19), regulated hydroelectric rate base remains more than double the nuclear rate base.

Please explain why OPG is proposing that the 49% equity thickness apply to all years in the five-year plan. On an assumption that there could be increased risk due to the increased risk from significant nuclear capital investments, why wouldn't the increased thickness only apply, if necessary, beginning in 2020 or 2021?

Response

a) The rate base values in Chart 1, from page 1 of Ex. C1-1-1 Attachment 1, are determined using a mid-year average methodology. As discussed at Ex. B1-1-1 page 4: "for large in-service additions or adjustments, where the in-service addition amount of the amount of an adjustment exceeds $50M, the month in which the addition or adjustment is reflected is used, instead of a mid-year average, to improve accuracy."

b) The following response was prepared by Concentric Energy Advisors:

OPG is proposing that the 49% equity thickness apply to all years in the five-year plan for several reasons. As discussed in Concentric's Common Equity Ratio Report (Ex. C1-1-1 Attachment 1, pages 13 and 14) the cost of capital (including the capital structure) is a forward-looking concept from the perspective of investors. OPG requires ongoing access to capital on reasonable terms in order to finance the Company's significant capital spending program over the 2017 to 2021 period and beyond. Investors and credit rating agencies are aware of OPG's elevated capital spending program and shifting rate base between 2017 and 2021. In order to ensure investors and rating agencies that there is regulatory support for cost recovery and credit quality, OPG's rates should reflect the increased risk profile of its elevated capital spending program and its shifting rate base to a higher percentage of nuclear assets relative to hydroelectric assets.

Although the first refurbished Darlington unit will not be brought into service until late in the test period, OPG will be making substantial capital investments over the next five years that will require access to capital on reasonable terms and that will place pressure on OPG's cash flows and credit metrics during this period. In particular, OPG forecasts total capital expenditures of approximately $5.25 billion on the DRP from 2017-2021 (Ex. D2-2-10, Table 1). DBRS has commented specifically on the risk associated with the DRP as follows:

> *DBRS believes that given the complexity and scale of the Darlington Refurbishment, there is significant execution risk as well as the potential for cost overruns. The high capital expenditures (capex) required, albeit spread over a ten-year period, in addition to ongoing maintenance capex (total capex forecast of approximately $2 billion in 2016), are expected to pressure OPG's key credit metrics.*[1]

DBRS also notes that OPG is expected to generate a free cash flow deficit in 2016 due to the large capital expenditure program.[2]

Credit rating agencies have also commented more generally about the credit risk associated with large capital spending programs. For example, DBRS writes:

[1] Ex. A2-3-1, Attachment 1, at 1
[2] *Ibid.*

> *For utilities undergoing significant multi-year capital expansion programs, capital spending may be considered a primary rating factor. This would be particularly relevant for companies with significant nuclear generation development.*[3]

Moody's has commented on the credit risk associated with capital spending plans:

> *Given the long-term nature of utility assets and the often lumpy nature of their capital expenditures, it is important to analyze both a utility's historical performance as well as its prospective future performance, which may be different from backward-looking measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance. In the illustrative mapping examples in this document, the scoring grid uses three year averages for the financial strength sub-factors. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including items such as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.*[4]

In an August 2016 report, S&P explains the importance of regulatory support for large capital projects:

> *When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors*[5]*.*

The proposed 49% equity thickness for OPG is conservative as compared to the authorized equity ratios for the operating companies held by Concentric's proxy group,

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[3] DBRS, Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry, October 2015, at 7.

[4] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, December 23, 2013, at 22.

[5] S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

none of which is a pure generation company like OPG. As discussed in Ex. C1-1-1 Attachment 1, page 32, Moody's views power generation as the highest risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operations, including the risk that incurred costs will either not be recovered in rates or recovered with material delays. In addition, nuclear generation is generally considered to be the highest risk generation source. DBRS explains:

> *Nuclear generation faces higher operating risk than other types of generation because of its complex technology (approximately 57% of OPG's production in 2015). Financial implications of forced outages, especially with older units (e.g., Pickering Nuclear Generating Station), are greater given the high fixed-cost nature of these plants as well as the fact that lost revenues from outages are not recoverable through rates.*[6]

[6] Ex. A2-3-1, Attachment 1, at 2

Ontario Energy Board

EB-2009-0084

Report of the Board

on the Cost of Capital for Ontario's Regulated Utilities

December 11, 2009

- The Board has determined that a split of 60% debt, 40% equity is appropriate for all electricity distributors. [67] Capital structure was not a primary focus of the consultation and the Board notes that the comments made by participants in the consultation largely supported the continuation of the Board's existing policy.

- For electricity transmitters, generators, and gas utilities, the deemed capital structure is determined on a case-by-case basis. The Board's draft guidelines assume that the base capital structure will remain relatively constant over time and that a full reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk. [68]

4.4 Debt Rates

4.4.1 Long-term debt

The determination of the cost of long-term debt was not a primary focus of the consultation and the Board notes that the comments made by participants in the consultation largely supported the continuation of the Board's existing policies and practices.

While the Board agrees with this approach, it is important to note that the determination of the cost of long-term debt has typically received significant interest in the processes to establish electricity distribution and, to a lesser extent, electricity transmission rates. In contrast to the difficulty establishing the utility cost of equity that arises from a lack of transparency, the issues associated with the determination of a utility's long-term debt cost arise from different factors, including the relatively short period of time since the corporatization of electricity distribution and transmission utilities, the relatively short history of rate regulation by the Board, and the presence of significant amounts of affiliate debt.

[67] Ontario Energy Board. Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors. December 20, 2006. p. 5
[68] Ontario Energy Board. Compendium to Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March, 1997. p. 30

GEC Interrogatory #2

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:

Please provide illustrative examples for the portion of each part of the DRP budget that is avoidable if the project is cancelled or curtailed at various stages. Please break this out to indicate the portion avoidable that falls within the amounts included in the current application. Please ensure that one scenario provided indicates what financial commitments would be avoidable if the project was cancelled today and what proportion of those avoidable commitments are included in the approvals sought in this case.

Response

OPG began refurbishment of Unit 2 on October 15, 2016 and has no plans to cancel or curtail the refurbishment at this stage or at future stages. OPG is unable to provide the requested illustrative examples. Any attempt to do so would be speculative, as it would be entirely dependent on assumptions that have no basis in fact. If OPG were to cancel or curtail DRP during the period covered by this application, OPG would inform the OEB and seek direction.

If the DRP were to be cancelled, the costs incurred to the date of cancellation, including accruals for work completed but not invoiced, would not be avoidable. Additionally, certain costs related to procurement commitments and demobilization costs, including costs to place the work in a safe state would not be avoidable.

The project spend to August 2016 was $2.6B (L-4.3-6 EP-18, Attachment 1, p. 2). In addition, as of September 30, 2016, accruals and commitments related to DRP were estimated at $478M (see L-4.3-13 PWU-8).

GEC Interrogatory #64

Issue Number: 1.3
Issue: Is the overall increase in nuclear payment amounts including rate riders reasonable given the overall bill impact on customers?

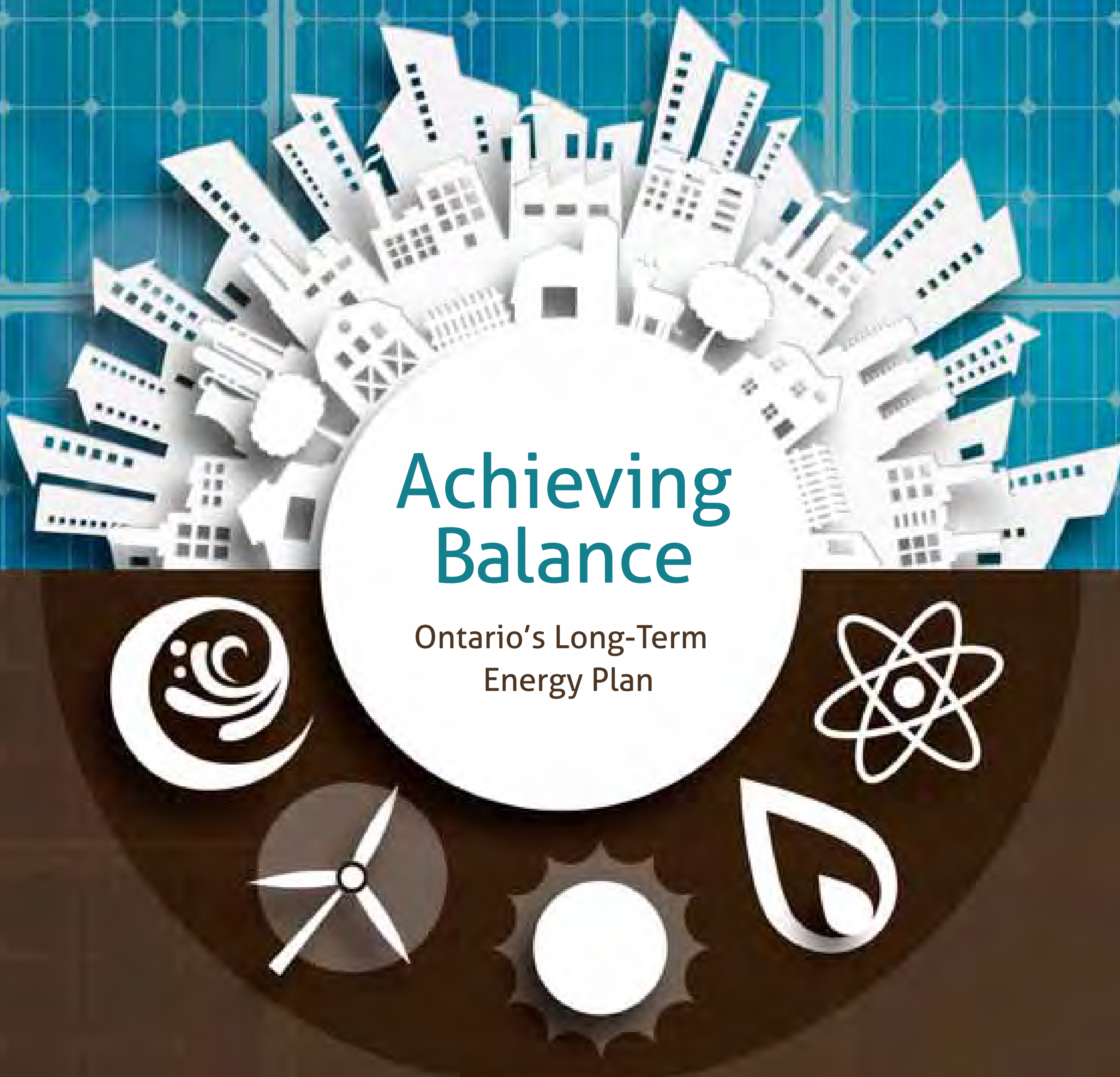
Interrogatory

Reference:

Please estimate the impact on payments and customer rates in each year of the 20 year deferral and recovery period, with and without the smoothing proposal, should the government require the exercise of an off-ramp in regard to the DRP at the completion of Unit 2 refurbishment.

Response

OPG is unable to provide the requested estimate and doesn't believe it is relevant to any issue on the approved Issues List. The costs that would be incurred if an off-ramp were to be exercised would depend on the timing of the decision and the specific direction from the Government regarding the future operation of Darlington. Any attempt to calculate 20 years of payment amounts without this information would be speculative, as it would be entirely dependent on assumptions that have no basis in fact. In the event the Government exercises an off-ramp during the period covered by this application, OPG would inform the OEB and seek direction.



Achieving Balance

Ontario's Long-Term Energy Plan

Ontario

Workers complete installation of a mock calandria in the Darlington Energy Centre. It will be used to test tooling and train workers before beginning refurbishment work inside the reactor vaults of the Darlington Nuclear Generating Station

30 universities and six major research centres, many of them in Ontario. The nuclear industry generates $2.5 billion in direct and secondary economic activity in Ontario every year. Retaining this nuclear expertise is crucial.

The province's nuclear generating stations at Darlington, Bruce and Pickering have historically provided about half of the province's electricity supply. The 2010 LTEP forecast that new capacity would need to be built at Darlington. New nuclear capacity is not needed at this time because the demand for electricity has not grown as expected, due to changes in the economy and gains in conservation and energy efficiency. The decision to defer new nuclear capacity helps manage electricity costs by making large investments only when they are needed.

Ontario continues to have the option to build new nuclear reactors in the future, should the supply and demand picture in the province change over time. The ministry will work with OPG to maintain the licence granted by the Canadian Nuclear Safety Commission, to keep open the option of considering new build in the future.

The government will ensure a reliable supply of electricity by proceeding with the refurbishment of the province's existing nuclear fleet taking into account future demand levels. Refurbishment received strong, province-wide support during the 2013 LTEP consultation process. The merits of refurbishment are clear:

- Refurbished nuclear is the most cost-effective generation available to Ontario for meeting baseload requirements.
- Existing nuclear generating stations are located in supportive communities, and have access to high-voltage transmission.
- Nuclear generation produces no greenhouse gas emissions.

Ontario plans to refurbish units at the Darlington and Bruce Generating Stations. The refurbishment has the potential to renew 8,500 MW over 16 years. The province will proceed with caution to ensure both flexibility and ongoing value for Ontario ratepayers. Darlington and Bruce plan to begin refurbishing one unit each in 2016. Final commitments on subsequent refurbishments will take into account the performance of the initial refurbishments with respect to budget and schedule by establishing appropriate off-ramps.

The nuclear refurbishment sequence shown in Figure 14 will be implemented subject to processes designed to minimize risk to ratepayers and to government. For example, appropriate off-ramps will be implemented should operators be unable to deliver the projects on schedule and within the established project budget.

The nuclear refurbishment process will adhere to the following principles:

1. Minimize commercial risk on the part of ratepayers and government;
2. Mitigate reliability risks by developing contingency plans that include alternative supply options if contract and other objectives are at risk of non-fulfillment;
3. Entrench appropriate and realistic off-ramps and scoping;
4. Hold private sector operator accountable to the nuclear refurbishment schedule and price;
5. Require OPG to hold its contractors accountable to the nuclear refurbishment schedule and price;
6. Make site, project management, regulatory requirements and supply chain considerations, and cost and risk containment, the primary factors in developing the implementation plan; and
7. Take smaller initial steps to ensure there is opportunity to incorporate lessons learned from refurbishment including collaboration by operators.

OPG ACTIONS TAKEN/PLANNED IN ALIGNMENT WITH LTEP PRINCIPLES

2013 LTEP – Nuclear Refurbishment Principles	**OPG Actions Taken/Planned in Alignment with LTEP Principles**
Minimize commercial risk on the part of ratepayers and government	• Locked down project scope well in advance of starting construction; • Fully developed engineering and planning of the work so that it is 100 per cent complete prior to the start of construction; • Built a full-scale mock-up of the Darlington reactor and vault and used them to fully test the tools and determine tooling durations in order to build a reliable schedule. All workers will be trained using the tools in the mock-up prior to working in the plant; • In phases, developed a Release Quality Estimate that incorporates a high-confidence budget and schedule for the work; • "Unlapped" Unit 2 from subsequent units so that the focus can be on planning and construction of a single unit to ensure its success while documenting lessons learned from the first unit and applying them to work processes on subsequent units; • Utilizing target price contracts for the execution phase that are based on developing cooperation, transparency, and risk sharing with key vendors; • Utilizing fixed price contracts for certain execution phase scope that is well defined and where risk transfer to a third party is appropriate; • Negotiated various off-ramps and stages into contracts; and • Established a robust risk management process to directly identify and administer commercial risks.
Mitigate reliability risks by developing contingency plans that include alternative supply options if contract and other objectives are at risk of non-fulfillment	• Decision to "unlap" Unit 2 from the other unit refurbishments, which predated the LTEP, was intended to mitigate performance risk and allow the DRP team to focus on refurbishing the first unit prior to commencing subsequent units. If the first unit is not successful, off-ramps are in place; the second unit refurbishment will not commence until the first unit is successfully returned to service. • Risk assessment and appropriate contingency and mitigation plans for each execution work package have been developed. • OPG's investment in the reactor mock-up is being used to perform full integration and commission testing of tools needed for refurbishment; lessons are being learned on the mock-up,

	not on the unit. The results of the mock-up testing have been incorporated into the tooling performance guarantee, which sets the target schedule and price, with the RFR vendor.
Entrench appropriate and realistic off-ramps and scoping	• OPG has engaged in a deliberate process with numerous off-ramps for the definition phase including Board of Directors oversight and annual releases of funds. • Each contract has off-ramp provisions allowing OPG to terminate, with or without cause; OPG would be accountable to reimburse contractors only for any reasonably incurred costs. • Scope review process in place to minimize scope of work performed in refurbishment period to address things that must be done to extend life or that can only be done in drained/defueled state. • OPG has fully examined the scope of the Unit 2 refurbishment project and optimized the work based on OPG's regulatory commitments and/or analysis of the best time to perform the work.
Require OPG to hold its contractors accountable to the nuclear refurbishment schedule and price	• OPG, in implementing all of its contracts, is highly focused on achieving value for money; there are incentives and disincentives related to achieving the cost and schedule set out in the contracts. • Contracts with major contractors have been developed and vetted utilizing a deliberate, staged and gated process with requirements for budget, schedule, scope, and risk identification at each gate. • Contracts have specific negotiated incentives and disincentives that are calculated toward promoting the contractor's (and OPG's) responsible management of the work. • OPG is implementing a detailed, integrated Level 3 schedule that will encompass all of the contractors' and OPG's work, as well as a rolled-up Level 2 Control and Coordination Schedule that is used as a higher level interfacing tool. • OPG has implemented cost control systems that are geared toward holding contractors accountable. These systems include earned value and budget controls, as well as validation of progressive project plans, through a gated process. • OPG performs analysis of all pricing and checks estimates for contractors' work. • OPG's senior management have established separate regular steering committees with each of the major contractors' executives which provide senior level leadership with a forum to discuss progress, potential and real issues impacting performance and commercial issues.
Make site, project management,	• RQE fully considered all of the factors listed in advance of execution of the work.

regulatory requirements and supply chain considerations, and cost and risk containment, the primary factors in developing the implementation plan	• Taking lessons from Pickering A, the DRP team completed the identification of all regulatory requirements well in advance of final design and construction. • OPG has completed the design and proving of the RFR tools. • Procurement of all long lead materials commenced well in advance of the start of the first unit refurbishment with all deliverable dates confirmed to be well in advance of the need dates. Mitigation plans are in place for any material that is not on hand well in advance of the need date. • OPG has implemented, in accordance with Project Management Institute standards and Association for Advancement of Cost Engineering best practices, project controls and risk management programs, as well as a continuous improvement focus, to refine these tools as the outage nears. • OPG has retained external oversight and engaged other corporate functions in providing input and assurance that the DRP team is meeting its commitments.
Take smaller initial steps to ensure there is opportunity to incorporate lessons learned from refurbishment including collaboration by operators.	• To fully incorporate lessons learned from the refurbishment of the first unit (Unit 2), the start of refurbishment work on the second unit (Unit 3) has been delayed until the completion of the first unit. While Unit 2 is underway, lessons learned will be captured and incorporated into Unit 3 planning. • OPG has filled key positions in its project management team with individuals having direct experience with prior CANDU refurbishments. • OPG has contracted with SNC/Aecon, whose subsidiary CANDU Energy (formerly AECL) has been associated with each of the prior refurbishments. • OPG and its contractors have studied lessons learned and operating experience from prior projects and incorporated those into the DRP. • OPG routinely collaborates with other CANDU operators directly and through the CANDU Owner's Group. OPG established a Memorandum of Understanding with Bruce Power to support collaboration.

GEC Interrogatory #8

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:

Please describe what differences exist between off ramp mechanisms for the Darlington life-extension and the life extension of the Bruce reactors.

Response

The 2013 LTEP refurbishment principles included establishment of realistic off-ramps and applied to both Darlington and the Bruce station.

For OPG's Darlington Station:

The Ontario Government can request OPG to stop the Darlington Refurbishment Program (DRP) at any time. OPG's contracts have built in off ramps with specific criteria, including paying out certain costs associated with accruals, demobilizations, and materials. The appropriate clauses are embedded into the contracts developed between OPG and its contract partners.

For the Bruce Station:

OPG has no access to information on off ramps for the Bruce station other than what is available publicly in the Amended Bruce Power Refurbishment Implementation Agreement (December 2015). Based on the Agreement posted on the IESO's website, OPG provides this summary:

- Both Bruce Power and the IESO have back out provisions, or "off-ramps", which can be leveraged in the agreement. The off ramp provisions govern situations where the parties may disagree as to whether refurbishment of a given unit should go ahead in light of predicted cost or schedule overruns.

- Where the cost of refurbishing any given unit exceeds either the price or duration thresholds set by the IESO, IESO may elect to proceed, or halt the refurbishment of a given unit, or of that unit and all yet to be refurbished units.

- IESO may also make such election where any given refurbishment is predicted to take more than six months longer than the locked-in planned refurbishment durations.

- Where the cost exceeds Bruce Power's cost thresholds (which are 50% over the unit threshold base amounts), IESO still elects whether to proceed with the project, but following that election, Bruce Power may elect whether or not it will refurbish the unit in question, or to cease refurbishing any further units. Bruce Power would have to demonstrate that the economics of the project are “significantly impaired” to evoke this clause and can only do so at certain key junctures.

- In general, where one party elects not to proceed with the work, but the other overrides that decision, the party that overrides shall compensate the other for any cost overages.

Board Staff Interrogatory #50

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Reference:
Ref: Exh D2-2-3, Chart 1

Interrogatory

a) Describe all "off ramps" for each major work bundle. What is the governing process for OPG to determine whether to exercise the off-ramps? How will this decision be communicated to all interested parties? What are the cost categories that will be payable to the contractors upon execution of each of the off-ramps?

b) Describe what information OPG will gather, who will receive the information, when the information will be provided, and how the decision will be made whether to the exercise the off-ramp during or after the completion of Unit 2. Provide the same information for all of the other units and the process OPG will use to assess whether to exercise the off-ramps throughout the project.

c) Describe the governing process regarding the off-ramp for when a prime contractor is substantially below expectation. What does "substantially below expectation" mean? What information will this determination be based on? Who will have access to that information, when will it be provided, and who will make that decision?

d) What actions must the contractors take to recover in the event of a project schedule delay for which the contractor is responsible?

Response

a) OPG has incorporated both a termination for convenience and a termination for default clause in each of its major work bundle contracts. This allows OPG to take an "off ramp" at any time and terminate its contracts:

Termination for Default: If the contractor defaults, OPG will be entitled to terminate the agreement and exercise a number of self-help remedies. Termination for default would permit OPG to make a claim against the contractor for full contractual damages (subject to a percentage cap formula that is linked to the total contract price and certain other amounts).

Termination for Convenience: The agreement permits OPG to terminate the agreement for convenience at any time. Certain types of direct damages (but not full contractual damages) will be payable by OPG to the contractor in such circumstances. Examples of direct damages under the contracts (with some variation between the contracts) are:

- work that has been performed to the date of the termination and for which OPG has not yet made payment;
- an equitable portion of any fees which would have otherwise been payable on the next milestone date;
- any contractor costs incurred in providing any work in progress; and
- reasonable extra direct damages suffered by the contractor arising from the termination (such as out of pocket costs for demobilization).

Each circumstance will be dealt with as appropriate based on the facts. There is no special governance process required other than compliance with the contractual terms. Formal communications will be made in accordance with the contract terms; additional communications will be made as appropriate. Prior to terminating any contract, the OPG Project Manager will request a review by OPG's Senior Management team, which includes Finance, Law and Supply Chain.

Upon decision to terminate for convenience, OPG is to provide written notice to the contractor, as set out in the contracts.

b) As discussed in L-4.3-1 Staff-44, beyond being guided by the 2013 LTEP principles for nuclear refurbishment, OPG has no insights into what factors the Government of Ontario would consider in making a decision to direct OPG to take an off-ramp.

Internally, if Unit 2, or any other Unit, was forecasting to be over budget beyond a certain threshold, OPG would be required to issue a superseding business case summary. The superseding business case summary would include information such as updated cost estimates, LUEC, and alternative proposals. The option to take an off-ramp may be one of many considered alternatives. Approval of any superseding business case summary would be sought from OPG's Board of Directors.

c) If a contractor is performing "substantially below expectation", OPG likely would terminate the agreement for default as opposed to termination for convenience.

Performance that is "substantially below expectation" will be determined on a case-by-case basis, but will include evaluation of the contractor's performance on safety, quality, schedule and cost aspects of the work being undertaken as well as their actions, or lack of action, taken to recover the performance gap.

d) OPG expects contractors to be on plan for their work. Recovery plans are required if a contractor deviates from plan and a milestone is at risk of being missed. Steering Committees consisting of senior management from both OPG and the contractor provide oversight on all aspects of contractor performance. OPG expects all defective parts of the project to be corrected at the contractor's cost. In some contracts, a schedule incentive/disincentive regime is in place to encourage the contractors to be on or ahead of schedule.

EP Interrogatory #35

Issue Number: 11.7
Issue: Is OPG's proposed off-ramp appropriate?

Interrogatory

Reference:

Has OPG prepared any plan for off-ramping the DRP? At what cost or delay in refurbishing Unit 2 would the company considering scrapping the refurbishment of later units?

If the company has any documents related to this question, please provide them.

Response

OPG has not prepared any plan for off-ramping the Darlington Refurbishment Program nor has OPG established a cost threshold or schedule delay where the company would consider cancelling the refurbishment of later units (please see L-04.3-1 Staff 44). Consistent with the principles in the 2013 LTEP, OPG has built appropriate clauses into its contracts that would allow OPG to exercise an off-ramp (please see L-04.3-8 GEC-8).

ONTARIO ENERGY BOARD

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and --

MR. POCH: No, you provided with unit 2 on the assumption you are going to proceed with the subsequent units.

MR. KEIZER: Right. And there is nothing factual or otherwise that supports your supposition.

MR. POCH: I am responding to your concern. If I can get the answer to this it would be helpful. If we could wind back the clock and it was going to be, you know, 4.8 just for unit 2 and you weren't going to be able to -- and you knew at the start you were never going to go past that, would you have proceeded? Would that make sense to do that project for 4.8, standalone?

MR. REINER: If -- we set out to do a four-unit refurbishment, and all of the investments that were made in planning in the prerequisite projects and the infrastructure projects are geared towards a four-unit project and running the plant for an additional 30 years beyond the refurbishment time period. So that's investments in safety improvements, that sort of thing.

If a decision had been made early on to not do four units and only do two, it would have taken us down a different path of planning, and there isn't an exercise that we could do to tell you how would that change the cost. It would be a very different scenario.

MR. POCH: You can't say if it would have made sense. It would --

MR. REINER: Yeah.

GEC Interrogatory #9

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:

If an offramp is exercised after unit 2 completion, how long does OPG estimate the remaining units would continue operating without refurbishment? What would be the annual revenue requirement impact of such a scenario?

Response

In the event that an off-ramp is exercised after the refurbishment of Unit 2 and the remaining three units were not to be refurbished, OPG would operate the remaining Darlington units for as long as they can continue to be safely operated and licensed to operate by the CNSC. This would require that all life-limiting components, in particular the fuel channels, continue to meet prescribed technical fitness-for-service requirements. Based on current assessments, the following would be the approximate shutdown dates:

Unit 3	early to mid- 2020
Unit 1	mid-to-late 2022
Unit 4	late 2023 to early 2024

The technical fitness-for-service assessments process is an on-going process and dates are subject to change.

OPG cannot provide the annual revenue requirement impact of this scenario. Such an exercise would be completely speculative and require OPG to make a large number of assumptions in many areas of its business, in addition to utilizing the nominal shutdown dates shown above. For example, the shutdown of the majority of the Darlington units in this time period, given the planned timing of the shutdown of the Pickering units, would require OPG to shrink its nuclear program from 10 operating units to 1 operating unit over a period of only a few years. The resultant major downsizing of the company would create fundamental changes to OPG's business. Downsizing costs, decommissioning plan changes, changes to labour strategies, potential changes in regulatory requirements, and changes in financing and cash flow needs, as examples, would all have to be understood and be factored into a revised revenue requirement calculation.