David I. Poch Barrister tel. (613) 264-0055 fax (613) 264-2878

1 October 2016

Ontario Energy Board
2300 Yonge St., 27th Floor
Toronto, ON
M4P 1E4

Attn: Ms Kirsten Walli
Board Secretary

By electronic filing and e-mail

Dear Ms Walli:

**Re: EB-2016-0152 OPG Payments – GEC IRs**

Attached please find GEC's interrogatories to OPG. Documents referred to that are not on the record will be uploaded to the RESS seperately.

Sincerely,

David Poch

Cc: OPG

1649 Old Brooke Road, Maberly, Ontario K0H 2B0 e-mail: dpoch@eelaw.ca

# GEC IRs to OPG

## Issue 3.1 - Capital Structure

1. C1-1-1 att.1 Concentric Report
   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.

**Issues 2.2 & 4.3 (DRP Rate Base & Capital)**

2. 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.

3. During its September 23rd presentation OPG indicated that it considered the price impact of alternate contracting approaches. Please provide the percentage impacts that were found to be associated with differing approaches for each major contract or work grouping included in the DRP.

4. Exhibit D2-2-11 Attachment 3 Page 9 of 122

   "It is typical for megaprograms, such as the DRP, to be managed on a planned duration that is less time than reflected in the high-confidence schedule."

   And at p. 10 "The Facilities and Infrastructure Projects (F&IP) and Safety Improvement Opportunities (SIO) were not necessarily completed per the initial planned schedule and estimate…"

   a) Please provide details of the various percentage schedule delays and percentage cost overruns in the F&IP and SIO projects relative to the high confidence schedule and estimate and the planned schedule and estimate.

   b) Please provide an analysis of the degree of adherence to date to the high confidence and the panned schedules for each major work component of the DRP. Please do so with reference to the highest level schedule (as described at page 31 of the Pegasus evidence) that existed at the time of OPG's prior OEB application and with respect to the initial version of the level 5 schedule.

   c) Please provide a complete history of the DRP's expected unit completion dates and outage duration schedules showing initial assumptions and changes to date.

5. Pegasus Report D-2-2-11 att. 3

   a) How many nuclear projects has Pegasus been retained to review?

b) How many times has Pegasus given evidence or provided analysis in regard to a nuclear project where Pegasus was retained by a project proponent or its counsel? How many times for parties opposing a nuclear project?

c) How many times have you found a nuclear project plan, planning approach or cost estimate to be largely reasonable, and how many times unreasonable?

d) Where you have found a nuclear project plan, planning approach or cost estimate to be generally reasonable, how many of the projects have ultimately been able to adhere to the cost estimate and plan timetable in place at the time of your review?

e) For each nuclear project that Pegasus has reviewed, please list the deviations from budget and completion time compared to the estimates in place at the time of the Pegasus review.

6. Please confirm that OPG in effect seeks a prudency ruling in advance on the $4.8B in DRP costs included in this application as coming into service by 2020 such that only variances therefrom will be subject to subsequent Board review.

7. Please provide all documents from the province describing the offramp mechanisms for the Darlington life-extension.

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

9. 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?

10. Please provide a table showing the refurbishment schedules for the Bruce and Darlington nuclear stations from the 2010 and 2013 Long Term Energy Plan directives and the current refurbishment schedule for the Bruce and Darlington nuclear stations. Please explain the differences and rationale for changes between the current and past refurbishment schedules.

11. GEC wishes to examine the historical accuracy and trends in OPG's (and Ontario Hydro's) cost estimates as reflected in LUEC estimates:

a) In 2016, the Office of the Information Commissioner ordered OPG to release the 2009 Levelized Unit Energy Cost spreadsheet for the Darlington refurbishment that was provided to its board of directors in 2009. (See: PA-12-394 attached.) Please provide the most recently updated comparable LUEC spreadsheet for the Darlington station post refurbishment. Please explain any differences.

b) Please provide all available past LUEC estimates for Darlington and the equivalent value in 2016 dollars (see for e.g. the NB Power undertaking attached). In each case please indicate whether the LUEC includes the stranded debt that OPG was relieved of. In each case please indicate whether the LUEC includes the DRP.

c) Please indicate and what similar historical analyses have been presented to OPG's Board and to the various review entities that OPG has retained for the DRP and provide these.

d) Please provide the LUEC cost for the Darlington nuclear station in 2016 dollars as actually experienced (without avoidable DRP costs). Please include costs with and without the applicable stranded debt.

12. In past submissions to the board, OPG has provided cost comparisons of the Darlington life-extension to alternatives, such as combined cycle natural gas. (see for e.g. EB-2010-0008, Exhibit D2-2-1, Attachment 4; EB-2013-0321, D2-2-1, Attachment 5, Updated 2014-02-06) No updated alternative comparisons were provided in the current application. Among other considerations, GEC expects that trends in such comparisons could inform a consideration of the likelihood of the government exercising the off-ramps.

    Please provide updated cost comparisons to the Darlington life-extension.

13. If not already filed, please provide copies of all of the quarterly oversight reports from Burns & McDonnell Canada and Modus Strategic Solutions Canada since 2014.

14. Exhibit D2-2-8 Attachment 1, page 28
    OPG states it has benchmarked the Darlington life-extension against CANDU projects at Point Lepreau and Bruce units 1 & 2. Has OPG reviewed and assessed Hydro-Quebec's cost estimates for rebuilding the Gentilly-2 reactor? Please provide cost estimates for the Gentilly-2 life-extension that OPG reviewed.

15. Did the contracts Bruce Power and New Brunswick Power signed with Atomic Energy of Canada Limited transfer more or less risk away from the utilities than OPG has obtained? Please explain.

**Issues 4.2, 4.3, 6.1, 6.4 & 6.5 (Impacts of Emerging Nuclear Regulatory Compliance Costs)**

16. Please provide a detailed list of plant modifications and their cost that OPG *has completed* in response to new regulatory requirements imposed by the CNSC in response to the Fukushima disaster. Please provide a detailed list of plant modifications and their cost that OPG *expects to complete* in response to new regulatory requirements imposed by the CNSC in response to the Fukushima disaster and confirm that these costs have been captured in the current application. Has the CNSC indicated whether it has finished adding regulatory requirements flowing from the Fukushima disaster?

**Issue 6.5 Pickering Extended Operations**

17. Exhibit F2, Tab 2, Schedule 3, attachment 1, pages 17 and 18:
These pages of the IESO's updated Pickering life extension analysis appear to indicate that Pickering life extension is not cost effective given the gas price projections offered and are only cost effective if a probabilistic assessment of the past distribution of gas costs is utilized. Please confirm, or provide OPG's alternative understanding of the IESO's report.

18. Exhibit F2, Tab 2, Schedule 3, attachment 1: Please confirm that IESO's analyses indicate that early shutdown of Pickering (i.e. 2018) offers the highest likelihood of reducing electricity costs. Please indicate whether OPG agrees with this analysis.

19. Exhibit F2, Tab 2, Schedule 3, attachment 1, pages 76 and 77: Please identify which Darlington lapping scenario reflects OPG's current DRP proposal.

20. Exhibit F2-2-3, Attachment 2: What gas price forecast underlies OPG's cost-effectiveness analysis? Please compare the gas price forecast used to the corresponding current Henry Hub futures prices.

21. In a March 23, 2016 article in Queens Park Briefing (See: *Pickering nuclear plant extension still a work in progress*, copy attached) OPG is reported to have issued the following comment on the Pickering life extension: "OPG says the component condition assessments are scheduled to be completed by this September, and the fuel channel life management work is slated to finish in the third quarter of 2017. This work could ultimately confirm the Pickering nuclear plant can live long and power. It's just not done yet." The article also notes: "There are regulatory hurdles remaining as well. OPG's

current operating licence for Pickering expires at the end of August, 2018. … Chiarelli said the life-extension plan would be contingent on the relicensing efforts. The government says OPG will ask it for a "final" approval to keep Pickering running after the company checks off all the regulatory boxes.”

a) Please confirm the accuracy of the statements.

b) Please confirm that a final decision on the Pickering service life will not occur until fuel channel life management work is completed and a relicensing decision is issued by the CNSC.

22. Please describe what planning OPG has undertaken in the event it does not receive approval from either the OEB or the CNSC to fund or operate Pickering until 2024. Please provide details of the impact on OM&A and on total revenue requirement in each year from 2017 to 2024 of such decisions if in 2017 or 2018 as applicable.

23. In 2014, Canada’s three reactor operators wrote to the Canadian Nuclear Safety Commission complaining that increased regulatory requirements have resulted in incremental one-time costs measured “in the hundreds of millions as well as ongoing year over year costs to maintain the capability measured in several tens of millions.” (See: A-2015-00037 Regulatory Framework Costs.pdf, attached). Please provide a breakdown of these increased one-time and ongoing costs due to increased CNSC regulatory requirements.

24. In 2014, OPG told the CNSC in regard to the 2013 licence for the Pickering Nuclear Generating that “….a total of eleven new or revised CSA Standards and CNSC Regulatory Documents were adopted in the licence, and currently approximately twenty new or revised CSA Standards and CNSC Regulator Documents (REGDOCs) are proposed for inclusion in the 2015 Darlington licence on its renewal. Each of these new regulatory documents have resulted in increased requirements and costs.” (See: A-2015-00037 Regulatory Framework Costs.pdf, attached)

    Please provide a breakdown of the anticipated additional costs resulting from the additional regulatory requirements in the 2013 Pickering and 2015 Darlington operating licences. Where do these costs appear in the costs filed before the OEB in this proceeding?

25. FOI Pickering Action plan 2015 15-058.pdf (copy attached) lists safety related initiatives at Pickering and notes that ‘whole site based safety goals’ are in development with tentative completion dates of phases A, B and C in 2015, 2016 and 2017. (More specifically, “Phase A results/status will be provided to the CNSC in the February 2016

update”). Please provide a copy of the 2016 update on the Pickering risk improvement plan as required under licence condition 5.1 of PROL 48.01/2018 and any available cost estimates for safety improvements that may flow from the study.

26. Please provide copies of the condition assessments completed in 2016 for the Pickering nuclear station.

27. Please provide any documents showing the CNSC’s acknowledgement that OPG wishes to continue operating Pickering until 2024. Please provide all documents detailing the CNSC’s expectations for submissions, including the period safety review, before the 2018 licence renewal hearings.

28. In 2013 and 2014, the CNSC instructed OPG to develop probabilistic risks assessments that considered the risk of all the reactors and waste facilities at the Pickering nuclear station.

    a. Has OPG embarked on this analysis?

    b. Is a similar analysis required for Darlington?

    c. Have or will these analyses change the core damage and large release frequency estimates for the Pickering and Darlington sites? Please provide any available results.

    d. What are the potential cost implications of increased risk estimates? Please explain.

29. Please confirm that the province has committed to hold public consultations on modernizing Ontario’s offsite nuclear plans post Fukushima and consider more severe accidents and confirm that the province has yet to consult the public or update offsite emergency measures post Fukushima.

30. How much does OPG provide to municipalities and the province of Ontario to maintain offsite emergency measures around the Pickering and Darlington nuclear stations?

31. Has OPG estimated what additional costs it may incur if the government of Ontario expands the current 10 kilometer evacuation zone (referred to as the Primary Zone) around Darlington and Pickering to 20 km or more? If so, please provide the cost estimates.

32. In 2014, the CNSC amended its emergency preparedness guidance to require potassium iodide (KI) pills be delivered to all residents within the 10 km primary zone and made available to anyone who wants them within the 50 km secondary zone by the end of 2015.
    (a) How much has OPG spent to meet this regulatory requirement? Please break down costs between the pre-distribution in the 10 km primary zone and availability within the 50 km secondary zone.

    (b) Is the cost of maintaining this programme included within the LUEC for the Darlington life-extension?

    (c) Has OPG estimated how much it would cost if a decision is made to require KI pre-distribution in the event that the province decides to expand the primary zone beyond 10 km? If so, please provide these estimates.

    (d) How often will OPG need to re-distribute these KI pills to meet regulatory requirements moving forward?

33. In Table 4 of Attachment 2 to Exhibit F2-2-2, OPG lists "level of concern" for fuel channel risks as high, medium and low.

    Please provide a likelihood range for the levels of concern marked low, medium and high.

34. In Table 3 of Attachment 2 to Exhibit F2-2-2, OPG lists "level of concern" for confidence in operation to 2022 to 2024.

    Please provide a likelihood range for the levels of concern marked low, medium and high.

35. Exhibit F2-2-3, Attachment 2, pg. 9.
    OPG states that "steam generators and feeders do not present a significant hurdle for proving fitness-for-service of the units." However, media reports indicate that recent inspections of Unit 4 "showed significant steam generator tube thinning in a number of tubes since the last outage inspections in Steam Generators 11 and 12, winter 2014 and fall 2011 respectively." (See: *pickering-nuke-plant-extension-to-cost-307m-may-prove-uneconomical-opg.pdf*, attached)

a. To what extent has this newly discovered thinning changed OPG's assessment of the risk of extending the operation Pickering until 2024?

b. Will this thinning of the steam generator tubes require increased inspections and monitoring moving forward? If so, how will it impact OPG's production forecasts and operation and maintenance costs?

36. Exhibit F2-2-3, Attachment 2, pg. 9.
OPG's current licence requires "OPG confirm, in writing, by June 30, 2017 the planned end-of-life date for Pickering." However, a government representative has said that OPG won't receive final government approval for the life-extension until after the CNSC hearings. (See: *pickering-nuke-plant-extension-to-cost-307m-may-prove-uneconomical-opg.pdf*, attached)

In the event OPG doesn't receive final government approval to operation Pickering until 2024, will OPG submit plans for closing Pickering in 2020 and 2024 as part of its licence application to the CNSC?

37. Exhibit F2-2-3, Attachment 2, pg. 14.
OPG states that an updated Periodic Safety Review, which evaluates the station against modern standards, will be required in advance of the 2018 re-licensing hearings. A briefing note with respect to OPG's decision to forgo refurbishing the Pickering B reactors in 2010 said "The CNSC requirement to review as built plant standards versus modern standards every ten years results in the potential for significant plant upgrades in the future." It states that the continued operation of Pickering in a targeted population growth area "carries the potential for significant regulatory sanction in response to public intervention." (See: 2010 Pickering Closure Briefing Note - FOI(1).pdf, attached)

a. Please describe when and how safety upgrades and enhancements will be identified and gain CNSC approval?

b. Has OPG identified any plant upgrades that may be required in response to Periodic Safety Review? If so, please describe them and their cost.

c. Please describe how cost benefit decisions are made regarding possible plant upgrades. Please provide copies of any CNSC or OPG policies that guide such decisions.

d. OPG’s “Technical and Economic Assessment of Pickering Extended Operations beyond 2020” states there is a medium risk that the results of this updated assessment may require physical modifications to the plant. Please define medium risk and quantify the potential costs. Has this assessment of media risk changed since this document was produced in October 2015?

e. Please provide a list reports or analysis OPG must submit to CNSC staff before the 2018 licence renewal hearings to meet the requirements for a Period Safety Review. What percentage of these submissions has been completed?

f. Please explain why “Management is confident that a list of reasonable and practicable safety enhancements can be reached with the CNSC staff in view of the 4 years of additional operation that is sought”? Please explain how “the 4 years of additional operation that is sought” would impact decisions on safety enhancements. How does the length of additional operation affect the list?

g. Did the CNSC impose additional (i.e. unplanned by OPG) licence conditions or safety enhancements during the 2013/2014 Pickering licence renewal? If so, please describe these conditions and their associated costs.

h. Did OPG reach an agreement with the CNSC regarding safety enhancements when it proposed to operate Pickering to 2020 before the 2013 licence renewal hearings. If so, what was that agreement?

38. Please provide Pickering’s total allocated operating costs between 2015 and 2024.

39. Please provide Pickering’s projected non-fuel operating costs between 2015 and 2024.

40. Please provide Pickering’s non-fuel operating costs by year since it began operating.

41. Exhibit F2-2-3, Attachment 2 page 5 says “data was provided to the IESO in December 2014 and again in October 2015 to facilitate the completion of an independent system economic value analysis.” Please provide the information OPG provided to the IESO in December 2014 and October 2015.

42. Exhibit F2-2-3, Attachment 2 page 5 says the value of operating Pickering beyond 2020 ranges from $0.5 billion to $0.6 billion. In contrast, in its 2013 application, EB-2013-0321, in F2-2-3, Schedule 3, OPG stated it estimated the net present value of operating Pickering to 2020 to be “approximately $520 million (2012 PV dollars).”

a. Please convert each of these estimates to 2016 dollars.

b. Using actual electricity demand since 2013 and current forecasts until 2020, please provide an updated estimate of the net present value of operating Pickering until 2020 using the same methodology used in EB-2013-0321 F2-2-3, Schedule 3 (i.e. holding other factors constant).

43. In EB-2013-0321 F2-2-3, Attachment 2 OPG filed the Ontario Power Authority's assessment of the prudency of operating Pickering until 2020. It stated: "On balance, the OPA's assessment of system cost impacts suggests an expected cost advantage to Pickering continued operation (in the order of approximately $100 Million). This advantage predominately reflects expected costs savings from reduced natural gas-fired energy production and lower replacement capacity requirements. Based on evaluation to date of the broader uncertainties, the OPA estimates a range of up to approximately $1.3 billion in potential net-benefit from Pickering continued operation to $0.76 billion in potential net-cost (dis-benefit). These estimates represent illustrative bookends and explore combinations of factors that together would increase or decrease the cost impacts of Pickering continued operations."

In EB-2013-0321, F2-2-3, Schedule 3, OPG's 2012 assessment of the Pickering continued operation estimates the net present value to be "approximately $520 million (2012 PV dollars)."

In contrast, EB-2010-0008, Exhibit F2-2-3, Attachment 2 states: "Depending on the amount of gas-fired generation or similarly-priced imports replaced by Pickering NGS generation, the overall system benefit could be up to 1.6 B$ (104 TWH multiplied by 15 $/MWh) due to the reduction of system costs."

a. Please provide a table comparing the demand forecasts used in the OPA's reviews of operating Pickering until 2020 filed in the past cases against actual demand and current forecasts.

b. Based on actual demand and current demand forecasts until 2020, is the continued operation of Pickering until 2020 a net system benefit or dis-benefit according to the OPA's earlier assessments?

c. Please define "system benefit" as used in these assessments. In answering this question please describe any differences between OPG and the OPA/IESO's definition of system benefit and explain if and how OPG and/or the OPA/IESO's definitions of “system benefit” have changed since the earlier assessments.

44. Has the decision to delay the refurbishment of a Bruce reactor from 2016 until 2020 changed the system benefit or dis-benefit of operating Pickering until 2020. Please explain.

45. Please provide a table showing how much of Pickering’s output has been surplus generation since 2010 and how much is forecast to be surplus until 2024.

46. What work is being delayed or could be delayed until such time as the Canadian Nuclear Safety Commission approves the safety case for operating Pickering until 2024.

47. Based on regulatory guide:
CNSC Regulatory guide *REGDOC-2.3.3, Periodic Safety Reviews*, (http://nuclearsafety.gc.ca/pubs_catalogue/uploads/REGDOC-2-3-3-Periodic-Safety-Reviews-eng.pdf ) says the following documentation must be submitted to the CNSC:

- PSR basis document
- reports on the review of each safety factor( safety factor reports)
- global assessment report (GAR)
- integrated implementation plan (IIP)

Please provide a timeline for the submission of these documents. If the documentation has been submitted, please provide copies. Please indicate whether CNSC has accepted any submitted documentation.

48. Regulatory guide *REGDOC-2.3.3, Periodic Safety Reviews* says “It is expected that the required effort to carry out a subsequent PSR of an NPP will often be considerably less than for the first…”.
Is this the first or second Periodic Safety Review for the Pickering A and B nuclear stations? Is OPG carrying out two separate PSRs for the “A” and “B” nuclear stations or one for the entire site?

49. CNSC Regulatory guide *REGDOC-2.3.3, Periodic Safety Reviews* says that a Periodic Safety Review should review a stations probabilistic risk assessments.
    a. Has OPG completed the probabilistic risk assessments that will be reviewed as part of the Periodic Safety Review required to continue operating Pickering until 2024?
    b. If so, please indicate when these probabilistic risk assessments were completed and whether they have been accepted by the CNSC.
    c. Please provide a table with the core damage and large release frequencies for the probabilistic risk assessments available.

d. Please provide the latest version of *N-PROG-RA-0016, Risk and Reliability Program.*

50. Please provide a list of CNSC Action Items relevant to the Pickering nuclear station that are currently under review.

51. The OPG cost benefit analysis presented in *P-REP-09013-0002, Pickering NGS – Beyond Design Basis Containment Integrity*, which dates from January 2014, recommended not installing a Containment Filtered Venting System (CFVS) in part due to the "the short remaining operating life of the station." OPG, however, has committed to install a CFVS at Darlington.

    a. Has the decision not to install a CFVS been revisited, and if so changed, in light of OPG's decision to extend Pickering's operational life again to 2024?

    b. If not, how long would OPG need to continue operating Pickering for the CFVS to be viewed as a reasonable upgrade?

    c. Has the CNSC accepted OPG's decision not to install a CFVS in light of its request to operate the station until 2024?

    d. Please provide a list of other safety enhancements or upgrades that OPG decided against installing prior to the 2013 relicensing hearings due to the plan to operate Pickering to only 2020.

52. Please provide the latest version of copy of *N-REP-31100-10055, Report on Technical Basis for Fuel Channels Life Cycle Management Plan*, which dates from 2011.

53. Please provide an updated table with information equivalent to *Table 1-1, Fuel Channel Life Limiting Mechanisms Units 5 – 8*, which is found in Attachment 1, OPG Letter, G. Jager to D.A. Desjardin and M. Santini, "Assurance of Structural Fuel Channel Fitness for Service for the Target Service Life of Pickering NGS, CD# P-CORR-00531-03724.

54. Re Pickering SOP:

    a. Please provide the latest version of the Pickering Sustainable Operations Plan (SOP), P-PLAN-09314-00001, which presents strategies and plans to support the operation of Pickering until end of commercial operation.

    b. Please indicate whether the latest SOP also considers extended operations until 2024.

c. If an alternative plan has been produced to govern extended operations until 2024, please provide a copy of that document.

55. Exhibit F2-2-3 Attachment 2

OPG states a partial release of 52M to cover the incremental Pickering work program costs in 2016 and 2017. Does this partial release include the costs of the Periodic Safety Review to support OPG's licence application and the extending of the operation of Pickering until 2024?

56. Exhibit F2-2-3 Attachment 1, page 36 (IESO's presentation evaluating the economic case for extending Pickering's operations until 2024.)

(Note: On page 48 of OEB staff's interrogatories, OPG is asked to consult with the IESO as necessary to respond to interrogatories related to the IESO's analysis of the Pickering Extended Operations. GEC makes the same request here.)

a. IESO states that Pickering's closure would present challenges related to the deployment of replacement supply. However, the government's 2013 Long Term Energy Directive directed OPG to plan for Pickering's closure in 2020 and potentially as early as 2017. What planning and procurement did the IESO undertake in response to the 2013 LTEP directive in order to secure adequate replacement supply to replace Pickering in 2020?

b. What is the IESO's current plan to secure replacement supply if OPG doesn't gain approval from either the CNSC or the OEB to extend Pickering's operational life until 2024?

c. In light of the province's "Conservation First" policy, did the IESO's cost analysis of Pickering's extended operations consider the additional cost effective conservation potential outlined in its June 2016 "Achievable Potential Study: Short Term Analysis" and how cancellation of the continued operations could affect conservation potential? If so, please provide details.

**Issue 6.1 Nuclear OM&A**

57. In 2015, the Nuclear Liability and Compensation Act received royal assent. The Act increases operator liability from $75 million to $ 1 billion.

a. Please provide estimated increases in accident insurance premiums between 2015 and 2021 to comply with the NLCA.

b. Please indicate if the increased premiums have been included in the evaluations of Pickering continued operations and in the DRP estimates filed.

**Issue 6.1 and 9.3 Nuclear New Build OM&A and Deferral**

58. The government's 2013 Long Term Energy Plan directive instructed OPG to maintain the approvals to permit the potential future construction of new reactors at Darlington.

a. Please provide a breakdown of how much OPG has or will spend to maintain its approvals to build new reactors since 2011 through 2016.

b. What costs will OPG incur to maintain approvals during 2017 through 2021?

c. Where do these costs appear in the application (i.e. in what component, rider or deferral account)?

**Issue 8.2**

59. Exhibit F2-1-1 Attachment 1 page 4 Table 1
How would the revenue requirement for Decommissioning & Nuclear Waste Management change if Pickering shuts down in 2018, 2020 or 2022/2024.

**Issues 9.7, 11.3 & 11.6 (Rate Smoothing)**

60. If not already done, please provide a copy of the September 23rd slides so they will appear in the record.

61. Please provide 20 year versions (covering the full deferral and recovery period) of slides 5, 6 and 9 of the rate smoothing presentation made on September 23rd. Please add a row with OPG's projected revenue requirement in each year.

62. For the 20 year deferral and recovery period, please add lines to each of the two approaches illustrated on Slide 9 of the September 23rd rate smoothing presentation showing the absolute and percentage difference in average monthly customer bills

between current bills and projected smoothed and unsmoothed bills in each year (as opposed to the year over year impact).

63. Please confirm that the customer impacts on Slide 9 of the September 23rd rate smoothing presentation do not include the impacts on customer total bills of expected coincident changes in generation costs incurred by the system overall (for example due to replacement generation and carbon fees). If OPG has considered this or has information from others that have considered this context, please provide.

64. 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.

65. 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 for a 25%, 50% and 100% cost overrun on the DRP and a 1 year, 2 year and 3 year delay in unit 2 return to service and logical combinations of these (as we assume a delay would also entail increased costs).

66. Please quantify the impact on nuclear payments and customer bills with and without rate smoothing if in this application we assume that Pickering life extension will not obtain CNSC approval or otherwise will not proceed and the implications if this unexpectedly arises subsequent to rates being set.