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2300 Yonge Street
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May 29, 2017
Our File: EB2016152

<u>Attn: Kirsten Walli, Board Secretary</u>

Dear Ms. Walli:

<u>Re: EB-2016-0152 – OPG 2017-2021 – SEC Redacted Public Final Argument</u>

We are counsel to the School Energy Coalition ("SEC"). Enclosed, please find SEC's redacted public version of its Final Argument. An underacted confidential version will be filed separately and distributed to the Applicant and OEB Staff only.

In redacting the information for this version we have erred on the side of caution. SEC requests that OPG review the redaction sections and advise what, if any, additional information can be placed on the public record. For ease, we have highlighted in grey the sections of the Final Argument that we have redacted in the public version.

Yours very truly,
Shepherd Rubenstein P.C.

Original signed by

Mark Rubenstein

cc: Wayne McNally, SEC (by email)
OPG and Intervenors (by email)

EB-2016-0152

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Ontario Power Generation pursuant to the *Ontario Energy Board Act* for an Order or Orders approving payment amounts for the generation of electricity for the years 2017 through 2021

FINAL ARGUMENT OF THE SCHOOL ENERGY COALITION (Public Version)

May 29, 2017

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1 OVERVIEW

1.1 *Introduction*

1.1.1 On May 27, 2016 the Applicant Ontario Power Generation Inc. ("OPG") filed an Application with the Ontario Energy Board (the "Board") to set just and reasonable payment amounts under section 78.1 of the *Ontario Energy Board Act* for the generation of electricity for the period commencing January 1, 2017. The Application seeks increases of $6 billion in its revenue requirement over five years[1] an increase of over 33% from existing rates, and a five-year capital program totaling more than $7.4 billion[2]. For a typical customer, such as a school, the Application proposes nuclear rates that, over ten years, would increase by 184%[3].

1.1.2 The biggest issues in the proceeding are, of course, the Darlington Refurbishment Program ("DRP"), and the Pickering Extended Operations which are being proposed essentially to support the DRP.

1.1.3 However, of significant importance are several other key issues:

- For the first time OPG has its future nuclear liability costs in a fully funded state.
- OPG continues to be challenged by compensation levels that are unreasonable, and are indicative of the same excesses that the Board has criticized in the past.
- The expansion of nuclear generation, and the construction risks of the DRP, are being presented to the Board as a basis to seek hundreds of millions of additional dollars from ratepayers through higher cost of capital.
- This is Canada's first ever five year IRM application for regulated generation[4].
- OPG's rate smoothing proposal would defer significant revenues, creating a ten year rate trajectory that includes an immediate and severe increase, followed by substantial and continuing increases and potential volatility over a decade.

1.1.4 OPG's Argument-in-Chief was filed on May 3, 2017. This is the Final Argument of the School Energy Coalition ("SEC").

1.1.5 The ratepayer groups who intervened in this proceeding have worked together throughout the hearing to avoid duplication, including exchanging drafts or partial

[1] K23.1, p.2, accepted by OPG Tr:23.4; Percentage accepted by OPG Tr.23:6
[2] $5,177M DRP, $950M hydroelectric, and $1,297M nuclear.
[3] Nuclear payment amounts of $168.35/MWh in 2026, compared to $59.29/MWh in 2016.
[4] And perhaps the first in North America.

drafts of their final arguments. We have been assisted in preparing this Final Argument by that co-operation amongst parties. Where we are in full agreement with the submissions of other parties, we have not repeated their arguments here, but have adopted their reasoning to the extent possible.

1.1.6 We also note that the Final Argument prepared by OEB Staff was filed on May 19, 2017. In some cases we agree with their conclusions, and where we have we have so stated in the body of these submissions. We understand that other parties are doing so as well. In other cases, we oppose the positions OEB Staff have taken. In those cases we deal with our opposition specifically in the reasons below.

1.1.7 The scope of this proceeding necessarily required prioritization by intervenors. As a result, we have not made submissions on every issue on the Issues List. Where SEC indicates that it does not have submissions on any issue, that should not be interpreted as agreement with the Application or any aspect of it, nor agreement with the position of any other party to this proceeding. Where we agree, we say so explicitly. Silence is just silence.

1.1.8 SEC attempted to make the numbering of Sections and Subsections in this Final Argument consistent with the numbering in the approved Issues List, but was unable to do so. We have instead marked the sections to show the issues they address.

1.2 ***Overriding Issues***

1.2.1 OPG's Final Argument, like its evidence throughout this proceeding, appears to be driven by a theme of "complexity". This is all very complicated, they say, but they have mastered the complexities and produced solutions that work. The Board, in OPG's view, should make sure that it delves deep into the issues, and gets the details right.

1.2.2 The other theme in this proceeding, and in SEC's view the one that should be the Board's main focus, is "outcomes". At its essence, this Application is about asking the customers to pay more for less. The Board, in keeping with its mandated role as a proxy for the competitive market, has to assess the extent, if any, to which that result is fair and reasonable.

1.2.3 ***Complexity.*** How many times in this proceeding did we hear OPG witnesses emphasize that their particular area of the evidence was very complicated? Whether it was their ROE experts, or their operating personnel, or their planners, or their regulatory staff, in each area there was a focus on the details, and how those details cannot be understood with any simple principles.

1.2.4 Even where OPG was emphasizing that they have everything under control, such as in the DRP evidence, the underlying assumption was still that the thing they have under control is inherently too complicated for the average person to understand. The "back up the truck" approach to DRP evidence, for example, while certainly justified in this case, placed a focus on the mass of details. The Final Arguments of the parties reflect this.

1.2.5 SEC does not disagree that many, maybe most, of the issues in this proceeding are highly complex. There are a lot of details. It is often challenging to grasp each and every nuance of those details.

1.2.6 Further, SEC is not for a minute suggesting that the Board should be unconcerned with those details, or should not pay sufficient attention to those details.

1.2.7 However, it is also true that the Board must still guard against a "forest vs. trees" problem. This is true in every rate case, of course, but it is particularly true here, where the volume of details is literally unprecedented in OEB history.

1.2.8 SEC believes that, in a case like this, the key role of the Board is to push through the complexities and details, and identify the essential principles at play on any issue. Sure, the details matter, but in almost every case it will be one or two principles that drive the fair resolution of each issue. The details will normally be secondary – pitfalls to be avoided rather than drivers of the overall result.

1.2.9 SEC therefore believes it is our role, in preparing this Final Argument, to assist the Board in pursuing that specific goal: the identification and application of core principles to the issues arising in this proceeding. Our analysis should be interpreted against that backdrop.

1.2.10 ***Outcomes.*** A theme that should have increased emphasis in this proceeding is "outcomes". The Board expected OPG, in this proceeding, to file an application that focused on outcomes valued by its customers, consistent with the RRFE. On the other hand, OPG is constrained by the reality it currently faces, and so proposes a five-year IRM period in which customers pay more, and get less.

1.2.11 This is not the place to expound on the concept of outcomes, whether as set out in the RRFE or as used by the Board more generally. However, in the context of this Final Argument, SEC understands outcomes to be a reference to the Board's longstanding role as a market proxy. The RRFE, and the market proxy concept, both require that each time a utility asks its customers to pay any amount (a rate increase, for example), the Board, as proxy for the customers, asks what the customers are getting for that payment.

1.2.12 The truth is that, at least to some extent (or at least in theory), the reason for the negative ratepayer outcomes from OPG in the short term is that the benefits of higher rates today will be enjoyed down the line, when the DRP has been completed. During the next five years, the impacts of the DRP, says OPG, will be stations offline, increases in operating costs, and continuing to produce high cost power from Pickering.

1.2.13 While that is partly true, it may also be true that the size and "scariness" of the DRP are being used to justify other increases in costs that are not really required for DRP, or can be delivered with greater efficiency.

1.2.14 Even if the Board concludes that ratepayers must bear some negative outcomes, just due to the inevitable impact of the circumstances now facing OPG, that does not mean the additional $6 billion OPG is seeking in the next five years is a proper reflection of those negative outcomes.

1.2.15 SEC therefore submits that the second theme on which the Board should focus is how much of the negative outcomes OPG is proposing for ratepayers are absolutely necessary. This is not just the Board's normal role in identifying the "reasonable" level of costs, or the "prudent" course of action. When the dollars are this high, and the justification for those dollars is the special circumstances of OPG, the Board, just like customers in the marketplace, should, in our view, apply a bias against all negative outcomes. And, it should reject all those negative outcomes that are not both inevitable, and essential to OPG's future.

1.2.16 ***Conclusion***. It is understandable that OPG would focus on complexity, which is an inherently utility-centric view of the situation, but is something they have to wrestle with every day. The Board cannot ignore that, although it can and should engage its normal role of distilling those complexities into principles on which good decisions can be based.

1.2.17 More important, outcomes are an inherently customer-centric view of the situation. SEC submits that, in a fundamental way, it is outcomes that should be the primary guide the Board follows in its deliberations on the issues in this proceeding.

1.3 ***Summary of Submissions***

1.3.1 This section provides a brief summary of the positions taken and recommendations made by SEC in this Final Argument.

1.3.2 ***Equity Thickness.*** There are two aspect to this: change in risk, and comparison to other utilities. SEC believes that on both measures, no change in equity thickness is warranted.

1.3.3 When the evidence of the experts is boiled down to its essence, the only material increase in risk OPG faces today is from the Darlington Refurbishment Project.

1.3.4 However, none of that risk is fairly included in determining equity thickness. To the extent that the ratepayers should bear that risk (i.e. where cost overruns or delays are prudent), they will bear those risks directly through the CRVA, and OPG will not. To the extent that the cost overruns or delays are imprudent, then as a matter of law and policy the ratepayers should not bear those costs, either at the time they arise, or in advance through an increased in the cost of capital.

1.3.5 This reality is reflected in the fact that the only objective observers of OPG risk, the rating agencies, make clear – after describing the execution issues DRP will present – that they have no expectation that OPG's rating will decline in the foreseeable future.

1.3.6 The fact is that, at 45%, OPG's equity thickness is already very high for Canada, being the highest in Ontario and one of the highest in Canada. US utilities typically have 10% higher equity ratio compared to Canada, yet it is rare that a US utility would have a 55% equity.

1.3.7 SEC therefore submits that the current 45% equity thickness is already at the top of any reasonable range, and should not be increased.

1.3.8 ***Darlington Refurbishment Project.*** The Darlington Refurbishment Project is the largest single project the Board will likely ever approve. SEC's main submissions regarding the DRP are as follows:

(a) ***Approvals***. The Board's review is limited by O.Reg 53/05[5]. That limits the Board authority to reviewing the cost of the project. It must accept the need. The regulation also restricts the Board's ability to approve, in this proceeding, the prudence of the forecast spend. Under the regulation, the Board can only determine prudence after the project has been completed. The Board should therefore simply approve the underlying costs, with the proposed modifications, only on an interim basis so as to include them in payment amounts. In the alternative, if the Board believes it can approve the project costs, subject to the CRVA, on a final basis it should not do so as one single project, but for multiple projects by area (i.e. bundle), and unit.

(b) ***Costs.*** A number of individual adjustments should be made to the costs included in the revenue requirement:

(i) OPG should be required to update the cost of the project to the most recent information available,

[5] Ontario Regulation 53/05, Payments Under Section 78.1 of the *Ontario Energy Board Act, 1998* S.O. 1998, c. 15, Sched. B ("O.Reg 53/05")

(ii) A contingency of P50, not the proposed P90, should be used for ratemaking purposes, and

(iii) Definition phase spending should be properly allocated across all 4 units, not just the first unit (Unit 2).

(c) ***Monitoring & Reporting.*** There are clear warning signs that the project is already at some risk. OPG's performance executing the F&IP and SIO projects is not a good omen for the remainder of the refurbishment. The Board must ensure that there is constant pressure on OPG to get this project right, and to provide all stakeholders (the OEB, ratepayers, the public) with timely and detailed information.

1.3.9 ***Nuclear Capital Rate Base & In-Service Additions.*** SEC proposes that a number of adjustments be made to the rate base and in-service additions forecasts for the test period. They include:

(a) Update the rate base continuity to incorporate 2016 actuals.

(b) Reduce the forecast in-service additions in each year of the test period by 12.5% to account for OPG's history of being over-budget and behind schedule on its capital projects. The Board should also make further reductions to account for the lack of efficiency and productivity initiatives in the test period.

(c) Make specific disallowances of $23M for the imprudent over-spending on the Auxiliary Heating System and Operations Support Building Refurbishment projects.

1.3.10 ***Nuclear OM&A & Benchmarking.*** OPG's proposed nuclear OM&A is unreasonable in light of both the lack of productivity initiatives built into the budget, and its worsening cost and reliability benchmarking. OPG's level of staffing is still a concern and, contrary to the view of the company, it is not at all clear that they have met the benchmark levels. The Board should make corresponding reductions.

1.3.11 ***Pickering Extended Operations.*** The Board has an obligation to ensure that costs that it approves are for activities that are needed and are reasonable. A review of the economic analyses undertaken by the IESO and OPG in 2015 that underlie the justification for extending Pickering until 2022/24 are no longer valid. The net benefits that are forecast are likely to disappear completely if the models were re-run based on updated and more accurate assumptions. The Board should deny the costs to extend (and operate) Pickering as proposed because they will lead to a system disbenefit, and higher customer bills.

1.3.12 ***Compensation.*** The Board should send a message to OPG that 'enough is enough', and ratepayers should no longer be responsible for compensation above the benchmark. Additionally, the benchmarking that was undertaken is inadequate and underestimates OPG's actual total compensation against peer comparators. SEC proposes that the Board should make reductions to the compensation budget of at least [redacted] a year, in aggregate [redacted], which represents only the amounts of reductions that can be precisely quantified.

1.3.13 ***Common Support Costs.*** OPG both benchmarks very poorly, and over-forecasts its common support costs. The Board should reduce OPG's corporate support costs that are allocated to the nuclear business by 2.5% a year, or $55.7M over the test period.

1.3.14 ***Nuclear Liabilities.*** The Board should reduce the amount included in rates for nuclear liabilities by $728M, from $1,808M as proposed by OPG, to $1080M, the amount determined by the Province to be payable by current customers under ONFA. There are three reasons for this change:

(a) OPG proposes to use outdated numbers to include $304.8M more in rates than even their own accounting calculations show is appropriate. This appears to be a straw man, and the Board should reject it as not a serious proposal.

(b) The Province has made a formal determination, in ONFA, balancing the intergenerational equity related to nuclear liabilities. The Board should not overrule that policy decision without compelling evidence that it would not be in the public interest, and that a different balance to achieve intergenerational equity is manifestly better[6].

(c) No part of the additional $728M that OPG proposes to collect will ever be used to cover the costs of nuclear liabilities, so the ratepayers would be paying this additional amount for no benefit, either now or in the future.

1.3.15 ***Rate Smoothing.*** The Board should reject the rate smoothing proposal from OPG, since it:

(a) Results in unacceptable levels of rate volatility in 2017, and

(b) Fails to properly forecast future WAPA over the next five years.

1.3.16 Instead, the Board should establish a smoothing mechanism, as required by O.Reg 53.05, that targets

[6] This should not be left up to accounting bodies. If the Board determines the Province is wrong, it should do so on its own analysis. There is no evidence that the accounting organizations are better placed to determine intergenerational equity than either the Province or the Board.

(a) a zero increase in WAPA when the new rates are implemented, and

(b) 2.5% per year in each of the remaining years, but

(c) with a higher increase where otherwise the nuclear payment amount would have to go down.

The smoothing amounts should be forecast now, including all known rate riders (including riders to recover any revenue shortfall) and forecasts of future rate riders, and should be adjusted in accordance with the formula when there are any changes to the nuclear or hydroelectric payment riders.

1.3.17 Further, SEC submits that, if the rate smoothing mechanism is to be finalized during the payment amounts order process, the Board should ensure that parties are given full opportunity for discovery and participation in the substantive aspects of that phase**.**

1.3.18 ***Hydroelectric IRM***. SEC submits that the price cap methodology proposed by OPG is appropriate, subject to the following changes:

(a) ***Inflation Factor***. The I in the I-X formula should be composed of:

(i) AWE for the 14% of revenue requirement that is OM&A–Compensation, the same as OPG has proposed but with a corrected weighting.

(ii) 0% Inflation for the 25% of revenue requirement that is the Gross Revenue Charge, since it is known to be NOT subject to inflationary cost pressures.

(iii) GDP IPI for the remaining 61% of revenue requirement.

(b) ***Productivity.*** Based on 0.29% TFP, as proposed by PEG and supported by OEB Staff.

(c) ***Stretch Factor***. SEC accepts the proposal of OPG that a 0.30% stretch factor is appropriate, given that OPG's hydroelectric performance appears to be in the middle of the range.

(d) ***2017 PCI Escalator***. The result of the above recommendations is an escalator for 2017 of 0.76%.

1.3.19 ***Capacity Refurbishment Variance Account – Hydroelectric.*** SEC accepts the revised CRVA methodology proposed by OPG in Ex. N3-1-1, but submits that the threshold for total capital expenditures funded in IRM rates is not the $749.1M of depreciation, but the $1,006M net amount funded by all capital components of rates, assuming the 0.76% PCI escalator SEC has proposed.

1.3.20 ***Hydroelectric Capital Variance Account.*** SEC has proposed that the Board allow no change to OPG's equity thickness. If the Board does order a change, then SEC submits that the proposed HCVA is inappropriate. OPG should either:

(a) Wait until its next rebasing to adjust its equity thickness, something that the Board has always done only in a cost of service proceeding, or

(b) Update its ROE from 9.33% to 8.78% at the same time as it starts to receive the benefit of a higher equity thickness, and include that adjustment in the HCVA as well in the same way as equity thickness.

1.3.21 ***Nuclear Rate-Setting & Mid-Term Review.*** The OPG proposed rate-setting framework for its nuclear assets does not meet the Board's expectations for a Custom IR application in a number of areas. The Board should make the following adjustments:

(a) ***Stretch Factor Amount.*** Based on OPG's own benchmarking information of its nuclear assets as a whole its stretch factor should be 0.6%. If the Board determines that OPG's general methodology of creating a production weighted stretch factor based on the results of each individual nuclear station, then using update benchmarking information, the stretch factor should be no less than 0.45%.

(b) ***Stretch Factor Application.*** The stretch factor, which is derived from total cost benchmarking information, should be applied to all aspects of OPG's proposed nuclear revenue requirement, with the exception of the DRP. The Board should apply the stretch factor to all aspects of OM&A and nuclear capital.

(c) ***Production Adjustment at Mid-Term Review.*** The Board should not allow OPG to adjust its production forecast during the 5 year test period. Doing so would be contrary to the RRFE and the Rate Handbook, and does not constitute an exceptional circumstance.

(d) ***Nuclear ROE Variance Account.*** For similar reasons, the Board should not approve the proposed variance account to collect the difference between the current ROE built into the test period revenue, and actual ROE. This is contrary to the RRFE and the Rate Handbook, and indirectly does what O.Reg 53/05 appears to be attempting to limit.

1.3.22 ***Effective Date.*** OPG had a responsibility to ensure that it filed this Application

– the biggest and most complex rate application in Canadian history – sufficiently in advance of its proposed effective date to allow a full review of the proposals it contains. OPG should not be allowed to avoid that responsibility. If it was in fact simply unable to file in a timely manner for a January 1, 2017 effective date, it should have filed for a January 1, 2018 effective date.

1.3.23 SEC submits that the effective date for new payment amounts should be the first day of the month following the Board's payment amounts order.

1.3.24 ***Clawback Proposal.*** OPG has proposed that it be allowed to claw back all lost revenue arising from any effective date later than January 1, 2017 through the Rate Smoothing Variance Account. SEC submits that the RSVA was not intended for this purpose, and the Board should be proactive in ensuring that it can't be used to subvert the Board's decision. To achieve that result, the Board should determine that revenue requirement for OPG from January 1, 2017 to the effective date should be equal to

(a) actual volumes for both hydroelectric and nuclear for that period, multiplied by the payment amounts previously authorized for that period; plus

(b) the cost of service based revenue requirement for 2017 ultimately determined by the Board, multiplied by the number of days from the effective date until December 31, 2017, divided by 365.

2 GENERAL (Issue 1)

2.1 ***Response to OEB Directions (Issue 1.1)***

No additional submissions.

2.2 ***Economic and Business Planning Assumptions (Issue 1.2)***

No additional submissions.

2.3 ***Increase in Nuclear Payment Amounts (Issue 1.3)***

The components of this issue are dealt with at length in the other parts of this Final Argument. On the general question of the level of payment amounts, please see also Section 1.2 above.

3 CAPITAL STRUCTURE AND COST OF CAPITAL (Issue 3)

3.1 *Introduction – Equity Thickness (Issue 3.1)*

3.1.1 SEC submits that, despite all the complexities presented in this proceeding on the issue of equity thickness, the reality is much simpler. In our submission, the Board's decision comes down to two points:

(a) In the end the only material change in risk for OPG at this time is the execution risk relating to DRP and Pickering Extended Operations.

(b) The DRP/PEO risk is realized through cost overruns or delays, which can only be of two types:

(i) Prudent, in which case they will be borne by the ratepayers through the CRVA, and not by either OPG or its financiers (debt or equity); or

(ii) Imprudent, in which case they cannot, in law, and should not, as a matter of policy, be borne by the ratepayers, whether at the time they arise or in advance, through a higher cost of capital.

3.1.2 SEC therefore submits that there are no circumstances in which the changes in risks currently faced by OPG are both actual business risks the company faces, and risks that should at any time be borne by the ratepayers**.**

3.2 *The Experts*

3.2.1 SEC submits that, after cross-examination by multiple parties, the evidence of Brattle and Concentric, the experts on equity thickness, is no longer either credible or useful. The Board still has to address the issue, and still has to be concerned with the underlying factors driving the issue: risk, credit metrics, etc. However, it must do so with little expert guidance.

3.2.2 In part, this is because both experts come from a pro-utility focus. They each make their living arguing on behalf of utilities in front of regulators that ROE should be increased, or equity thickness should be increased[7]. The Board did not have a truly independent expert on cost of capital providing evidence in this proceeding, and it has an evidentiary gap because of that. As will be seen in the following sections, the results of their studies reflect the basic biases of their client base[8].

3.2.3 In the following sections, SEC will seek to point out areas in which the Board can glean some limited information from the experts, but will also identify other sources of

[7] Tr.18:114-5; Tr.19:58
[8] To no-one's surprise, perhaps, neither expert even looked at the impact of their proposed change in equity thickness on the ratepayers who would have to pay it: see Tr.18:111; Tr.19:85.

information on the record that can form the basis for the Board's determination.

3.2.4 In SEC's submission, the evidence shows that the business risk of OPG has not changed in any material way, so an increase in equity thickness is not warranted. Further, SEC submits that the current 45% equity thickness is at the high end of the reasonable range, and may not even fully reflect the lower levels of equity that the Board and other Canadian regulators have historically allowed for Canadian regulated utilities as compared to U.S. regulated utilities[9].

3.3 ***Change in Risk***

3.3.1 It is common ground that the Board does not change the Board-approved equity thickness used to calculate revenue requirement unless the evidence before them demonstrates a material change in the utility's business risk.

3.3.2 Concentric, in its report, identified six areas of increased business risk[10]. The risks identified by Brattle were a subset of that list, so in cross-examination the Concentric list was used[11]. There is also a useful list of risks in the 2017-2019 OPG Business Plan, some of which are on the Concentric list[12].

3.3.3 The experts do not agree on either the existence or materiality of each risk, and the business plan is different still. SEC has prepared the following table to try to identify the differences[13]:

[9] SEC have reviewed the Energy Probe analysis in its Final Argument of the impact of the standalone principle, which is in addition to the points we are raising. While it is clear that OPG is simply not financeable on a true standalone basis – see Tr.19:91, 98-99, 119, and other references – it was not necessary for us to address this sub-issue given the approach we took to the analysis.
[10] C1-1-1, Attachment 1, p.5; Also see K18.4, p.2
[11] Tr.18:121 et seq.; Tr.19:88 et seq.
[12] N1-1-1, Attachment 1, p.3; Also see K18.4, p.3
[13] Reasons for each yes or no are described in the text that follows the table.

Comparison of Risks					
Risk	***Concentric***		***Brattle***		***In the BP?***
	Increased?	***Material?***	***Increased?***	***Material?***	
Change in hydro/ nuclear asset mix	Yes	Yes?	Yes	No	No
Darlington Execution Risk	Yes	Yes	Yes	Yes	Yes
Pickering Ext. Ops./aging	Yes	No	Yes	Yes?	Yes
Longer term and hydroelectric IRM	Yes	No	Yes	No	No
Pension/OPEBs recovery risk	Yes	No	No	No	No
Rate smoothing recovery risk	Yes	No	No	No	No

3.3.4 We note that both experts identify a proxy group, but that is not strictly speaking a change in business risk. We deal with the proxy groups in Section 3.4 below.

3.3.5 ***Nuclear vs. Hydroelectric Asset Mix.*** Both experts state that, in their experience, a higher percentage of nuclear correlates to a higher level of business risk. In Concentric's case, it was unclear whether they believe this is a material change in risk[14]. In Brattle's case, it was clear that, in their view, while this is a risk[15], it is not a big risk[16].

3.3.6 It is also true that this risk is not in the OPG Business Plan, where management is required to list the risks facing the business. Concentric was at a loss to explain why this was not identified as a risk by OPG management[17].

3.3.7 SEC put to both experts the fact[18] that, in their own proxy groups, there is no correlation between nuclear/hydroelectric asset mix and equity thickness. While Concentric accepted that fact was true[19], both experts argued that it was faulty methodology to seek to draw a single correlation out of a data set to demonstrate the existence of a relationship, or lack thereof. Both asserted that to study that question would require a review of other relevant factors[20].

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[14] Tr.18:121
[15] Tr.19:105
[16] Tr.19:88
[17] Tr.Tr.18:121-2
[18] K18.4, p.27
[19] Tr.18:149
[20] See Tr.19:108

3.3.8 Both were therefore asked repeatedly whether they had any studies, or could provide any sources, for their assertion that risk (and therefore presumably required equity thickness) increases as the percentage of nuclear assets increases. Neither was able to provide or refer to any such studies[21], both of them implying that no such studies exist.

3.3.9 Further, SEC notes that, from the point of view of percentage of production from nuclear vs. hydroelectric in the test period, that is actually moving in favour of hydroelectric, and will continue to do so once Pickering is closed. Concentric agrees that fact affects risk[22].

3.3.10 SEC submits that the Board has no credible evidence that increasing the percentage of nuclear assets is a material increase in business risk. The only actual evidence is

(a) the proxy groups, which goes the other way, and is in any case challenged by the experts, and

(b) the OPG Business Plan, which does not identify this as a risk worth talking about in the plan.

3.3.11 For these reasons, SEC submits that the shift in asset mix should be rejected by the Board as an increase in business risk for OPG.

3.3.12 ***Darlington Execution Risk.*** Both experts agree that this is the major risk currently faced by OPG, and the key material increase in risk[23]. It appears to be the only material change in risk[24]. For example, after a discussion about various risks and their impact on her recommendations, in which Dr. Villadsen downplayed the importance of all of the other risks, she described this execution risk as follows[25]:

> *"MR. SHEPHERD: All right. So really when it comes down to it -- and tell me whether this is right -- you're saying this is a utility that is going into a big capital program, that's inherently riskier, and, all other things being equal, they need more equity to support that level of risk; is that fair?*
> *DR. VILLADSEN: That's fair."*

3.3.13 This is also, of course, highlighted in the 2017-2019 Business Plan as a key risk[26], one

[21] Tr:18:146, 151, 154; Tr.19:105
[22] Tr.18:159
[23] Tr.18:124; Tr.19:88, 90
[24] Although Brattle lumps it together with Pickering: Tr.19:88
[25] Tr.19:125-6
[26] K18.4, p.3. The BP, for example, refers to "significant write-offs" and "reputational risk" if the company does not bring the project in on time and on budget.

that has been in fact described at various times in this proceeding as one on which the company's future is riding.

3.3.14 Thus, there appears to be unanimity that the DRP is a very risky project. SEC agrees, and frankly it would be shocking if anyone who had heard the evidence in this proceeding did not agree.

3.3.15 The question with the DRP, which we deal with below, is the extent to which the DRP risk is a <u>business risk</u> of OPG or not.

3.3.16 ***Pickering Extended Ops/Aging.*** Both experts identify this as a risk, and Brattle lumps it into the same bucket with DRP for the purposes of assessing materiality[27]. Concentric, on the other hand, says this risk did not have any material impact on their equity thickness opinion[28].

3.3.17 In the Business Plan, OPG management raises as a risk, not the execution of the project, but the potential costs of failure to get approval for the extension of Pickering operations[29]. Concentric agreed with this assessment[30].

3.3.18 The eventual conclusion of Concentric was that the change in risk with respect to Pickering is that it is three years older[31]. Once this Board determines whether Pickering Extended Operations can go ahead, the remaining aspects of the risk are gone.

3.3.19 SEC asked OPG to show that they considered Pickering Extended Operations to be a sufficiently material risk that they flagged it to the Government. The only thing they could point to was the 2016-2018 Business Plan, which talked about both Pickering and Darlington, and said[32]:

> *"Early identification of age-related degradation of station components and discovery of unexpected conditions require a timely risk management and continuing maintenance focus."*

3.3.20 There was no mention, either in the undertaking response, or in the 2016-2018 Business Plan, of any communication to the Government or the OPG Board of Directors that Pickering aging would put pressure on OPG's credit metrics or capital formation.

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[27] Tr.19:88
[28] Tr.18:141
[29] K18.4, p.3
[30] Tr.18:139
[31] Tr.18:140
[32] K18.1

3.3.21 SEC therefore concludes that, on the evidence before the Board, there has been no material increase in risk related to Pickering NGS.

3.3.22 ***Hydroelectric and Nuclear IRM and Term.*** While both experts have identified this as a risk for OPG, both appear to agree that it is not a material risk.

3.3.23 In the case of Concentric, it accepts that the Board does not consider the entry into an IRM ratemaking model as a factor that increases business risk[33]. Concentric also acknowledges that OPG has not identified IRM as a risk in their 2017-2019 Business Plan[34].

3.3.24 Brattle expressly acknowledges that this is a low risk[35], and it did not change their view on the appropriate equity thickness[36]. Brattle also notes that regulators don't generally increase equity thickness or ROE when a utility enters IRM[37].

3.3.25 SEC therefore submits that, on the evidence before the Board, there is no material increase in business risk arising out of OPG's entry into the five year IRM program.

3.3.26 ***Pension/OPEBs Cost Recovery.*** While Concentric identifies this is a risk, both experts make clear that it is of little consequence. Dr. Villadsen says it is not important[38], and would not impact her opinion[39], and Concentric says it is only an issue if there are insufficient assurances from the Board with respect to eventual recovery[40]. The 2017-2019 Business Plan says the same thing[41].

3.3.27 SEC agrees with the consensus that there is no material risk associated with pensions and OPEBs cost recovery[42].

3.3.28 ***Rate Smoothing Cost Recovery.*** The same conclusion arises with respect to rate smoothing. Dr. Villadsen does not treat it as a separate risk, since it is a function of the substantial capital spending plan[43]. Concentric, on the other hand, does treat it as a risk, but admits that if the eventual rate smoothing approved by the Board is not worse than the plan original proposed by OPG (which had $1.4 billion of deferred revenues),

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[33] Tr.18:161
[34] Tr.18:123
[35] Tr.19:89
[36] Tr.19:125
[37] Tr.19:97
[38] Tr.19:89
[39] Tr.19:125
[40] Tr.18:124
[41] K18.4, p.3
[42] Unless, of course, the Board in its decision expresses doubt as to whether this differential is recoverable from ratepayers eventually.
[43] Tr.19:89

there is no incremental risk[44].

3.3.29 Rate smoothing is not identified in the 2017-2019 Business Plan[45].

3.3.30 SEC therefore submits that, on the evidence before the Board, there is no increase in business risk related to rate smoothing recovery.

3.3.31 ***The DRP "Business Risk".*** SEC submits that the evidence is very clear. The only material risk that anyone has identified is the execution risk with respect to the Darlington Refurbishment Project. Therefore, the only determination the Board has to make is whether that risk is in fact a business risk of OPG, and one for which the Fair Return Standard requires that OPG's equity thickness be increased.

3.3.32 SEC submits:

- ***(a)*** The risks associated with the DRP are not risks that will be borne by OPG, but will be borne instead by ratepayers.

- ***(b)*** To increase the equity thickness, and therefore rates to those who will ultimately bear the cost of any execution risks, is charging the ratepayers twice for the same cost.

3.3.33 As the Board heard extensively in this proceeding, OPG is protected from downside risk on the DRP in multiple ways, two of which are critical.

3.3.34 First, the CRVA and other deferral and variance accounts protect OPG from any cost overruns or delays that are prudent and/or necessary. They don't bear the normal risks of the project, those things that a reasonable planner could not have foreseen. Those risks are borne by the ratepayers, and the Board has no discretion to relieve the ratepayers of that risk, or shift it to OPG. The Board is bound by regulation.

3.3.35 Second, to the extent that OPG is imprudent, and thus incurs additional costs, its borrowing is from the province, its shareholder. The cost of imprudent spending will be borne by the public at large.

3.3.36 SEC submits that with respect to risks that result from prudent actions, the ratepayers will bear those anyway. To increase equity thickness to cover the current implied cost of those risks would be to ask the ratepayers to pay for those risks twice, once now when they are inchoate, and once later when they are actualized.

3.3.37 That is not what is intended by the use of equity thickness. The point of increasing the

[44] Tr.18:123
[45] K18.4, p.3

equity thickness is to assign a cost for risk to the customers reflecting amounts that the shareholders eventually will bear in the future. Since that is not the case here, any part of the execution risk that involves prudent actions should not be included in equity thickness today. We, the customers, will pay for it – every single dollar - if and when it happens.

3.3.38 With respect to the risk that management will be imprudent, SEC submits that it would be inequitable to ask the ratepayers to bear that risk. Under O.Reg.53/05, it is clear that the government does not contemplate assigning the costs of imprudent spending to the ratepayers (e.g. via the CRVA). It should be no more appropriate to assign the risks of those costs to the ratepayers. Otherwise, the Board would simply be asking the ratepayers to bear imprudent costs, just indirectly.

3.3.39 SEC therefore submits that, with respect to the only increased risk that the evidence has identified, it is inappropriate to ask the ratepayers to pay anything with respect to that risk. If it arises due to prudent actions, it will in any case be borne by the ratepayers through the CRVA. If it arises due to imprudent actions, it should be borne by the shareholder, and not the ratepayers, whether before or after it is realized.

3.4 ***Proxy Groups***

3.4.1 Each of Concentric and Brattle did a comparison to a proxy group of U.S. companies. In both cases, the proxy groups were shown to be useless for the Board[46].

3.4.2 With respect to Concentric, it turns out that the equity thickness that was used in the analysis for each of the proxy companies was not the actual equity thickness of the company. It was the equity thickness approved by the utility's regulator[47]. Concentric didn't even look at the actual equity ratios of the companies[48]. Thus, all the Concentric proxy group tells the Board is how other regulators, all in the U.S. (which allows higher equity – see below), have decided to assign equity thickness. If the Board has a desire to follow the pack, this information would help you do that.

3.4.3 Further, having measured the wrong thing, Concentric then notes that their proxy group is not really comparable to OPG[49], because there are no companies that are comparable to OPG[50]. The companies in the proxy group are integrated utilities that are primarily in the wires business, and have different business risks from OPG.

[46] We note that, in the addition to the points we have made in the analysis that follows, SEC has reviewed CME's analysis of the proxy groups, and we note that analysis contains additional useful information, and comes to the same conclusion.
[47] Tr.18:164
[48] Tr.18:166
[49] Tr.18:172
[50] Tr.18:173

3.4.4 SEC submits that there is no value provided to the Board from the Concentric proxy group.

3.4.5 With respect to Brattle, they do measure actual equity thickness rather than approved, and they agree that is the more appropriate approach[51].

3.4.6 On the other hand, Brattle has only eight companies in its proxy group, because they excluded the three with the lowest equity thickness[52]. Their justification for that varied. For example, in the case of the largest, Bonneville Power, it was because it borrows from the government rather than on the markets[53] (just like OPG).

3.4.7 SEC submits that the Brattle proxy group is too small to be of value to the Board, and is skewed by the removal of three companies that are more like OPG than some of the others left in the group.

3.5 ***Canadian vs. U.S. Utilities***

3.5.1 SEC put to Concentric their own analysis of the difference between Canadian and U.S. regulators in allowed ROE and equity thickness[54]. The comparison, which Concentric does annually, has consistently[55] shown, for at least the last ten years, that Canadian equity thickness is about 10% lower than U.S. equity thickness for comparable sectors. The only reason the analysis is restricted to distribution and transmission companies is that there are no regulated generators in the U.S.[56]

3.5.2 Concentric made no adjustment to its opinion for the consistent difference between Canadian and U.S. equity thickness[57]. The explanation they give, in cross-examination, is not credible and appears to be just trying to avoid the issue[58].

3.5.3 Dr. Villadsen, when asked about the difference between equity thickness in Canada and the U.S., said that U.S. comparators are the only ones available for OPG, so "we use the best benchmarks we can find"[59]. She too did not adjust her opinion for the longstanding difference between equity thickness in Canada and the U.S.

3.5.4 SEC submits that failure to consider the structural differences in Canadian and U.S. regulated utilities – differences that have existed for a very long time – is a fatal flaw

[51] Tr.19:62
[52] Tr.19:111
[53] Tr.19:112
[54] K18.4, p.28-31
[55] Tr.18:171
[56] *Ibid*
[57] Tr.18:175
[58] Tr.18:175-6
[59] Tr.19:113

to both studies. Both studies are purporting to make adjustments of a few percentage points, while ignoring a 10% or more difference between their empirical data and the jurisdiction in which they seek to apply it. This is like saying that prices, in "dollars", are higher in Hong Kong than in Canada, while ignoring the fact that the Hong Kong dollar and the Canadian dollar have different values.

3.5.5 The interesting secondary impact here is that the expert studies, which reach unadjusted conclusions of 48% and 49%, may have inadvertently provided the Board with some directional information. Adjusted for the ongoing 10% difference between jurisdictions, their conclusions would be 38% and 39%, which would suggest that the 45% already approved for OPG is very high.

3.6 ***Rating Agencies***

3.6.1 Brattle actually looked at credit metrics as part of their analysis. Concentric did not. However, both were unwilling to consider the opinions of the rating agencies as having any relevance to OPG's business risk[60].

3.6.2 DBRS, after highlighting the significant execution risk associated with the DRP, decided to affirm OPG's rating with a Stable outlook[61].

3.6.3 S&P, after analyzing OPG in some detail, said it was "highly unlikely" that it would downgrade OPG in the next twenty-four months[62]. In fact S&P said that it would only consider a change in rating if OPG's AFFO to debt ratio went below 9%. It is common ground among the parties that there is no reasonable risk of this happening during the test period[63].

3.6.4 The only truly independent analysis before the Board related to the risks of OPG, viewed from a financing perspective, is the analysis of the two rating agencies. Neither appears to be concerned. Nothing in either of their reports suggests that they have identified a material change in business risk.

3.7 ***Equity Thickness - Conclusion***

3.7.1 SEC submits that, on the evidence before the Board, there has been no material change in OPG's business risk that would justify an increase in equity thickness. The only material increase in risk is one that is borne solely by the ratepayers, and not in any way by OPG. This conclusion is confirmed by the rating agencies, which have not changed the OPG rating to reflect any change of risk, and have not identified any potential for a change in rating in the future.

[60] Tr:19:116; Tr.18:183-4
[61] 3.1-Staff-017, Attachment 2, p.1
[62] 3.1-VECC-008, Attachment 2, p.4
[63] See, e.g. Tr.18:189

3.7.2 Further, SEC submits that if the equity thickness is increased because of the DRP, the effect is to make the ratepayers pay twice for the same risk.

3.7.3 Aside from the change in risk, SEC submits that the head-up comparison by the two experts to proxy groups does not assist the Board, except indirectly perhaps. The proxy groups are not appropriate benchmarks for OPG, and the experts essentially admit as much. They claim they are the best they can do, but that doesn't really help the Board. Further, the proxy groups are U.S. companies, and yet the experts have made no adjustment for cross-border regulatory differences. As a result, even if the proxy groups were proper benchmarks, they would show that the existing OPG equity thickness is too high, not too low.

3.7.4 SEC therefore submits that the Board should leave the equity thickness at 45%.

3.8 ***Return on Equity (Issue 3.1)***

This is a settled issue.

3.9 ***Cost of Debt (Issue 3.2)***

Subject to implementing the impacts of the Board's decision on equity thickness, this is a settled issue.

4 DARLINGTON REFUBISHMENT PROJECT (Issues 2.2, 4.3, 4.5, 6.4, 10.4)

4.1 *Overview*

4.1.1 In this proceeding, OPG is seeking approval for $5.17 billion in capital additions, and $126.9 M in OM&A, in the test period for the DRP.[64] The entire DRP, from initial project approval until the end of the execution phase, will span 15 years, at a forecast cost of $12.8 billion. The execution phase, the refurbishment of the four Darlington reactors alone, will take 10 years.[65]

4.1.2 The approvals sought in this application are for the capital additions and related project OM&A costs during the test period (2017-2021) as well as for 2016.[66] This includes a number of discrete support projects (F&IP and SIO), as well as the first refurbished reactor, Unit 2.

4.1.3 The DRP is the largest and most complex individual project the Board has ever been asked to review and approve. It is the most expensive and likely the most complex project OPG itself has ever undertaken. Reviewing the significant amount of information in the evidence has been a serious challenge, but an important one considering the size of the amounts at issues. While OPG is only seeking approvals for the test period, the DRP is an integrated project that spans not just the one unit that it forecast to be back in service, refurbished, in this test period, but the entire four units of the Darlington generating station.

4.1.4 Adding to the backdrop of this project is OPG's own history, and the nuclear industry's own history of megaproject cost overruns.

4.1.5 The Government of Ontario, through amendments to O.Reg 53/05, has required the Board to accept the need for the DRP.[67] Because of this, the Board cannot conduct its normal assessment of a capital project. It cannot determine, based on the cost and the risk of cost overruns, if OPG should undertake the project. What the Board can and must do is ensure that the costs of the project are reasonable, and considering the history of cost overruns of megaprojects, the planning and managing of the DRP are being done with the utmost level of care and scrutiny.

4.1.6 The Board heard during the oral hearing that the total cost of the project really is already forecast to be more than $12.8 billion. OPG has forecast an additional $800M in management reserve it will spend for low probability, high impact risks that are hard to predict, but are not included in the project budget.[68] In addition, OPG has reclassified $327M in capital and $533M in OM&A costs that it had previously

[64] A1-2-2, p.4-5
[65] D2-2-8, Attachment 1, p.23
[66] A1-2-2
[67] O.Reg 53/05, s.12(v)
[68] Tr.3:40; 4.3-AMPCO-103, p.2

included within the scope of the DRP project, to nuclear capital.[69] Together, OPG is more accurately expecting to spend an additional $1.65 billion. This $12.8billion has really already become a $14.55 billion project.

4.1.7 As discussed in detail below, there are already warning signs that the performance of various contractors is putting the successful execution of the project at risk. Further, OPG's largest contracts are target price, which means that ratepayers are on the hook for a disproportionate amount of any cost overruns.

4.1.8 SEC is providing overall comments related to the DRP project, and what specific approvals should be granted, specifically:

- ***Approvals Sought***. The Board is legally restricted in what it can approve in this Application with respect to the DRP as required by O.Reg 53/05. It cannot review the need for the project, and it cannot determine the prudence at this point either. It can only review the prudence of the DRP after its completion.

  Even if the Board does believe it has the ability to approve the proposed DRP costs on a final basis, subject to the CRVA, the Board should not do so on a global basis as is being proposed. The Board should ensure that the method of any approvals it does decide to provide at this time is suitably disaggregated. The DRP is most accurately not one but hundreds of different individual projects. The Board should not approve the DRP as one single project. If approved at all, it should be by area (i.e. bundle), and unit.

- ***Baseline Costs, Contingency & Definition Phase Allocation***. OPG's baseline costs should be updated to the most recent information available. The Board should also only allow inclusion of a P50 contingency as opposed to the proposed P90. Further, the Board should ensure that the definition phase planning costs are properly allocated across all 4 units of the refurbishment, instead of only the first unit (Unit 2).

- ***Significant Reporting and Monitoring Is Required.*** The nature, complexity, and sheer magnitude of the DRP requires much more extensive public/regulatory reporting and monitoring than OPG is proposing. There are significant warning signs that the project is already at some risk. OPG's performance executing the F&IP and SIO projects is not a good omen for the remainder of the refurbishment. The Board should ensure that there is constant pressure on OPG to get this project right, and to provide all stakeholders (the OEB, ratepayers, the public) with early warning if things are going wrong.

[69] JT 1.16; 4.3-AMPCO-105

4.2 ***O.Reg 53/05 Restrictions***

4.2.1 Unlike most capital projects undertaken by OPG that are reviewed by the Board in the setting of just and reasonable rates under section 78.1 of the *Ontario Energy Board Act*, the DRP has specific legal restrictions on its review.

4.2.2 Most notably, and not controversial, is the meaning of section 12(v) of the O.Reg 53/05. It requires that the Board "shall accept the need for the Darlington Refurbishment Project in light of the Plan of the Ministry of Energy known as the 2013 Long-Term Energy Plan and the related policy of the Minister endorsing the need for nuclear refurbishment".[70] The Board's role is thus limited to what is the reasonable amount ratepayers should have to pay for the project.

4.2.3 The Board is also restricted by section 6(4)(ii) of O.Reg 53/05, which requires that the Board ensure recovery of prudently incurred costs and firm financial commitments for the DRP, if OPG's Board of Directors did not approve them before the Board's first payment amounts order:[71]

> 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 <u>were prudently</u> <u>incurred</u> and that the financial commitments <u>were prudently made.</u> [emphasis added]

4.2.4 This provision is the basis for the Board's capacity refurbishment variance account, and it applies also more generally to all capacity refurbishment expenditures.

4.2.5 But the section also restricts when the Board can make the prudence determination. Subsection (ii) provides that the Board shall ensure recovery "if the Board is satisfied that the costs were prudently incurred and that the financial commitments were

[70] O.Reg 53/05, s.12(v)
[71] *Ibid*

prudently made." Both of these references are clearly in the past tense.

4.2.6 At this time, almost all the costs that OPG is seeking approval for are forecast costs.[72] They have not been incurred, so no prudence determination can legally be made. The clear language requires the Board to approve the costs only after they have been incurred, not beforehand as is normally the case in forward test year applications.

4.2.7 The section does make a distinction between "prudently incurred" costs, and "prudently made" financial commitments. SEC accepts that insofar as the Board can determine which of the forecast costs are "firm financial commitments", those could legally be approved in this proceeding, at least with respect to the assets which are to be in-service in 2017 through 2021. Most of the DRP forecast costs do not come within this category, and the evidence before the Board does not allow the Board to identify this category of costs.

4.2.8 This is not to suggest that it would be good rate-setting policy to exclude any forecast DRP costs from the payment amounts. If the Board were to include no costs, then payment amounts would not reflect the underlying costs to produce electricity.

4.2.9 SEC therefore submits that, to make the regulation's language consistent with good regulatory policy, the Board should at this time include the reasonable forecast costs, as determined by the Board, in payment amounts as a placeholder, with the final determination on their prudence occurring after the fact, as required by the regulation.[73]

4.3 ***Nuclear Megaprojects Sobering Performance Record***

4.3.1 The evidence in this proceeding regarding the history of megaprojects is sobering. They always go over-budget and run behind schedule.

4.3.2 OPG's CEO Mr. Lyash testified that megaprojects, "in general have a high risk of going over budget and over schedule, nuclear or otherwise."[74]

4.3.3 Mr. Roberts put it succinctly it in his expert report:

> *"Universally across all segments of the construction industry, it is difficult to successfully complete a mega-project or mega-program. Because the*

[72] SEC agrees with OPG that there is no distinction between prudence and reasonableness (Argument-in-Chief, p.35) citing *ATCO Gas Pipelines Ltd. v. Alberta Utilities Commission*, [2015] 3 SCR 219, para 35. The same has been said of the *Ontario Energy Board Act* specifically, where the Divisional Court commented that "'[p]rudent'means 'reasonable'" (Canadian Union of Public Employees (Power Workers' Union), Local 1000 v. Ontario (Energy Board), 2012 ONSC 1080, para 40)

[73] For the remainder of this analysis of the DRP, when we refer to Board 'approvals', we are referring to the approvals for the purpose of setting payment amounts, not a determination of prudence.

[74] Tr.1:99

vast majority of megaprojects are not completed on time and within budget, researchers have called the "'iron law of mega-projects': over budget, over time, over and over again".[75]"

4.3.4 Nuclear megaprojects, including refurbishment projects, are just as bad if not worse than megaprojects in general. In Canada, Pt. Lepreau and Bruce Power have had significant cost overruns just in the last decade. The refurbishment of the single unit facility at Pt. Lepreau was forecast to cost $1.4 billion and take 1.5 years; it ended up costing $2.4 billion and took 4.5 years.[76] Meanwhile the Bruce Power A restart project was forecast to cost $4.25 billion and take 5 years; it ended up costing $7 billion and took 7 years.[77]

4.3.5 OPG's own experience with Pickering A Return to Service and the Niagara Tunnel, not to mention its predecessor Ontario Hydro's track record with construction of Darlington, should give all stakeholders of this project deep pause.

4.3.6 OPG's return to service for all four units of Pickering A was originally forecast, when approved in 1999, to cost $840M and be completed by the end of 2002. [78] Unit 4 alone ended up costing over $1.25 billion and took 7 months longer than the original schedule for the entire project.[79]

4.3.7 OPG's Niagara Tunnel project was the most recent megaproject, and was originally forecast to cost $985M and be completed by June 2010. It ended up costing close to $1.5 billion and entered service more than 2 and half years late.[80]

4.3.8 Internationally, nuclear refurbishment and construction megaprojects have also had significant cost and schedule overruns, with significant issues recently at the Votgle Nuclear Generating Station in Georgia[81], and the Watts Bar Nuclear Generating Station in Tennessee[82].

4.3.9 The Board must ensure that, even after determining what amount is reasonable to approve, it keeps an eye on OPG's progress in executing the projects to ensure that OPG remains focused on ensuring an on-budget and on-schedule completion. As Mr. Roberts commented in his report "[s]uccesses in delivering mega-projects and mega-programs are rare." Even the best of intentions of OPG are not sufficient to ensure

[75] M1, p.47
[76] 4.3-SEC-033, Attachment 3, p.10
[77] See 4.3-SEC-033, Attachment 3, p.4
[78] Schiff Hardin & White: Report on Findings - *Root Cause Analysis of Pickering A Unit 4 Return to Service*, December 12, 2003 (M1-4.3-SEC-1, Attachment 15, p.3)
[79] *Ibid*
[80] 4.3-SEC-021
[81] 4.3-AMPCO-102, Attachment 2; M1, p.51
[82] 4.3-SEC-033, Attachment 3, p.15; M1, p.52

ratepayers are protected from cost and schedule overruns. Even if the Board subsequently disallows costs that are imprudently incurred, the scale of potential overruns is so large that the resulting effect on the ratepayers, or on the shareholder, i.e. the taxpayer, will be very significant.

4.4 ***Project Costs***

4.4.1 **_Baseline Costs._** OPG is seeking approval of costs, including the amount that will be in-service for Unit 2, based on the November 2015 Release Quality Estimate ("RQE") which was approved by its Board of Directors.[83] OPG has a more updated forecast, which was approved by its Board of Directors in August 2016.[84] This Unit 2 Execution Estimate ("U2EE") was still forecasting the total project cost will remain at $12.8 billion, but provides a more accurate bundle-by-bundle cost estimate, and a more specific Unit 2 cost estimate.[85]

4.4.2 While the total DRP project cost of $12.8 billion has not changed, SEC submits the Board should use the updated U2EE, and specifically the Unit 2 cost summary, as the more appropriate basis for approvals.[86] Even though the amount is slightly higher, it provides a more accurate forecast of the costs that will be incurred for Unit 2.

4.4.3 **_Contingency Costs._** OPG has budgeted $1.71billion[87] in contingency ($2.01 billion including interest and escalation[88]) for the entire DRP, and $684.1M[89] ($689.5M with interest and contingency[90]) for Unit 2.

4.4.4 OPG has set the contingency amount for the project based on a P90 confidence level.[91] The amount of contingency was determined by identifying project and program risks, and quantifying their probability of occurrence and their cost impact if they did materialize.[92] OPG then used a Monte Carlo simulation to forecast the required contingency for each confidence interval, i.e. the probability level that the project will come in on budget.

4.4.5 Using that analysis, OPG determined that it would be appropriate to set the confidence

[83] D2-2-18, p.1,9
[84] 4.3-Staff-055, Attachment 1
[85] *Ibid*, Appendix 2A-3A
[86] *Ibid*, Appendix 3A
[87] D2-2-8, p.7
[88] 4.3-Staff-055, Attachment 1, p.11
[89] D2-2-8, p.9; Technical Conference Transcript Vol.1, p.44. The amount is rounded.
[90] 4.3-Staff-055, Attachment 1, p.13. There is a discrepancy in the Unit 2 RQE contingency in the prefiled evidence which states the amount is $694.1M (D2-2-8, p.9) and the RQE number provided in U2EE amount noted at $689.5M. This was noted at the hearing but never addressed (Tr.2:38-39). The new U2EE estimate reduces the amount to $677.5M (Tr.2:39).
[91] Tr.1:32
[92] 4.3-AMPCO-076, Attachment 1,4;

level for the amount of contingency at the P90 level. This means that OPG believes that, with the included amounts for contingency, the project is has a 90% probability of coming in at or below budget.[93]

4.4.6 SEC submits that including a contingency amount that makes it 90% likely the project will come in at or below budget is inappropriate. The appropriate contingency amount is a P50 level, which recognizes that there is an equal chance the project will come in below or above budget, depending on whether risks materialize.

4.4.7 OPG's position is that the P90 is an appropriate confidence level for a project this complex.[94] Yet, it chose not to apply the same logic and standard to its own contractors who had target price contracts.

4.4.8 In OPG's single largest DRP contract, the Retube and Feeder Replacement ("RFR") contract with the Aecon/SNC-Lavalin Joint Venture (the "Aecon SNC JV"), the contingency budget included in the target cost used a similar method as the OPG's RQE contingency amount.[95] Risks were identified and a Monte Carlo simulation was conducted.[96] A P50 contingency amount was chosen.[97]

4.4.9 When asked in Interrogatory AMPCO 44 why P50 was selected for the RFR target contract contingency amount, OPG responded that to do otherwise would not be appropriate:

> *"P50 means that, all other things being equal, there is an equal probability of the final result being better than or worse than the calculated outcome. <u>It would not be appropriate, when negotiating a contract, for either party to aim for higher than P50, as that would imply that one party was attempting to achieve greater certainty at the expense of the other party taking on more risks. P50 is also a standard analysis based on AACE International Recommended Practice No. 18R-97.</u> A P50 analysis was established by OPG prior to the RFP process and agreed to by the contractor during the RFR negotiations." [emphasis added]*[98]

4.4.10 SEC agrees with OPG's responses to the interrogatory. It would not be fair for one party to have a greater degree of risk than the other. The same rationale applies to the relationship between OPG and its ratepayers. A P90 would represent, in OPG's own words, "that [OPG] would be attempting to achieve greater certainty at the expense of [ratepayers] taking on more risks."

[93] Tr.1:32
[94] Argument-in-Chief, p.56-57
[95] D2-2-3, Attachment, p.2
[96] 4.3-AMPCO-033, Attachment 1, p.7
[97] Tr.3:44; 4.3-AMPCO-044(b)
[98] 4.3-AMPCO-044(b)

4.4.11 Indeed, OPG recognizes that using a P50 is a standard approach that is recognized by the AACE Practice No. 18R-97[99], the same standard that it has used for the purposes of determining its own project budget.[100] Both Dr. Galloway and Mr. Roberts said AACE was the industry standard.[101]

4.4.12 When confronted with that at the oral hearing, OPG tried to explain away this difference by saying a contractor is in a different position from the ratepayer.[102] But it is clear there are a lot of similarities between the contractor in a target price contract and ratepayers. OPG's response to why it would not accept a P90 from a contractor was quite revealing. Mr. Reiner stated the dangers of managing to a P90 level with the contractors:

> *"MR. REINER: ... If you manage to a P90 level inside the contractor space, we may not get that kind of visibility into those issues. So the place that we opted to land with the contracts is to create that transparency, create that tension that recognizes there is a 50 percent likelihood this could go over budget so we always have visibility and focus on the issues that are being managed."*[103]

4.4.13 These are exactly the same concerns ratepayers have with OPG managing the project to a P90 level. A P90 does not provide transparency to ratepayers, nor does it create that "tension" (as OPG calls it) that requires OPG to ensure that it is executing the project as best it can. Ratepayers should be able to expect OPG to manage to the P50 budget, the same performance level OPG expects its contractors to achieve.

4.4.14 The $1.71 billion (or $2.01 billion with interest and escalation) understates the amount of total contingency that is built into the total DRP budget. It only represents the amount of contingency that OPG holds itself, but not the amount that is built into the contracts it has with its various vendors. There is an additional $371M built into the RFR execution phase contract, and $28.4M in the Turbine Generator EPC contract.[104] In addition, there are contingency amounts in the Stream Generator EPC, Turbine Generator Engineering Support and equipment Supply contract.[105] But, since those contracts were bid on as fixed price inclusive of any contingencies, OPG has no visibility to what percentage of the fixed price the vendor has allocated to contingency[106].

[99] 4.3-AMPCO-044(b)
[100] D2-2-11, Attachment 3, p.23
[101] M1, p.17, see footnote 33
[102] Tr.3:44-46
[103] Tr.3:46
[104] 4.3-AMPCO-72(f); Tr.3:42
[105] Tr.3:42; 4.3-AMPCO-72(f)
[106] 4.3-AMPCO-72(f);; Tr.3:42

4.4.15 While some parties may argue that including no contingency is appropriate, SEC does not support that approach. Prudent management should include a level of contingency. SEC does agree with the OPG's view that at least some of the contingency will be used, since you cannot mitigate all risks. The question is the level of appropriate contingency to be built into the budget and be approved.

4.4.16 Dr. Galloway aptly explained that the selection of the confidence level for contingency "primarily is reflective of the risk appetite of the owner."[107] But this Application is not about a conservative budgeting exercise for OPG's shareholder. It is about setting the contingency level that best reflects the reasonable cost of the project that ratepayers are being asked to pay. Rate-setting and project planning are not the same thing.

4.4.17 SEC submits that the Board should reduce the contingency that it approves to the P50 level. For Unit 2, based on OPG's own calculation, which is simply pro-rating the difference of the P50 and P90 contingency levels for the entire project, it yields a reduction in forecast costs of $116M.[108] The revised contingency amount for Unit 2 would be $578M inclusive of interest and escalation.[109]

4.4.18 ***Definition Phase Allocation Unreasonable.*** SEC has concerns with OPG's proposal to allocate the entirety of the definition phase planning costs to Unit 2, even though they were incurred to plan all four units of the refurbishment.

4.4.19 By the end of 2015, OPG had spent $2.2 billion on definition phase spending.[110] Those costs can be best broken down into two general but separate categories.

4.4.20 The first is self-contained projects, such as the RFR Mock-up, the SIO and F&IP projects.[111] Those costs are forecast to go in-service when they are individually complete.

4.4.21 The second is the more traditional refurbishment planning costs, such as engineering, budgeting, working with the contractors to prepare, getting necessary parts, and training etc.[112] This second category of planning costs represents about $1 billion of the $2.2 billion of total definition phase costs.[113]

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[107] D2-2-11, p.25
[108] 4.3-CCC-018(b). We note that, to be correct, this figure should be recalculated using a new Monte Carlo simulation. The figure would likely be lower than the pro-rated figure provided by OPG, since probability curves are not usually linear.
[109] *Ibid*
[110] D2-2-4, p.2
[111] Tr.3:21
[112] Tr.3:22
[113] *Ibid*

4.4.22 OPG's proposal is to allocate the $1 billion in planning costs entirely to Unit 2.[114] OPG's position is that allocating the planning costs to Unit 2 is appropriate since the work was all required for refurbishment of that unit.[115]

4.4.23 This is not credible. If OPG had undertaken a one unit refurbishment, those planning definition phase costs would have been less. While not 75% less, it would have been some significant amount less than was planned. This is because OPG explicitly planned the project as an integrated 4 unit refurbishment:

> *"MR. REINER ….Now, had somebody said to OPG, "We only want you to refurbish one unit, not four units; that's all the long term energy program requires," there might have been a different approach in planning. I would say there likely would have been a different approach taken.*
>
> *But that's not what we were asked to do. We were asked to develop a plan for the refurbishment of the entire facility. And our plan and the method we went about this is, in our view, a reasonable way of executing a four-unit refurbishment at Darlington."*[116]

4.4.24 SEC submits it is inappropriate to allocate all those costs to the first unit. They should be spread across each of the 4 units. Since there is no simple way to make an allocation, and recognizing that the costs are not split equally[117], SEC recommends the Board only allocate 50% of the definition phase planning costs to Unit 2. The remainder should be allocated among the other 3 units, to be collected from ratepayers when those units go into service. This recognizes that these important definition phase planning costs would not have been incurred if there was only one unit refurbished and as Mr. Reiner testified, "a different approach" would have been taken. It also recognizes that additional planning costs will be incurred for the three remaining units.[118]

4.5 ***Not One Giant Project But Many Large Projects***

4.5.1 The DRP is not like any other project that the Board has previously approved. While the overarching goal of the project is to refurbish the Darlington generation station to extend its operating life, it is not a single project. More accurately, it is a collection of many different projects. The DRP is made of 501 discrete projects, categorized into 7 different bundles or groupings.[119]

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[114] *Ibid*
[115] Tr.3:23
[116] Tr.3:24
[117] We note that, in any comprehensive cost allocation method, costs would be allocated to all the activities causing them.
[118] J3.2
[119] 4.3-AMPCO-033(b)

DRP Projects		
	Project Bundle Grouping	# of Projects
1	Retube and Feeder Replacement	17
2	Turbine Generator	27
3	Balance of Plant	234
4	Fuel handling/Defuelling	26
5	Steam Generator	23
6	F&IP SIO	24
7	OPG Programmatic/Functional	150
	Total	**501**
	Source: L-4.3-AMPCO 33(b) Chart 1	

4.5.2 In this Application, OPG is seeking approval for the capital component of parts of the DRP, to put into rate base the dollar value of various projects as they go into-service.[120] The largest is the projects (or partial-projects) that relate to the in-service additions for Unit 2 in 2020. The total amount in this Application is $5,177.4M.[121]

4.5.3 If there is any overspending or underspending compared to the approved amounts, or difference in the forecast in-service dates, the revenue requirement difference of those changes will be included in the CRVA for review and deposition at a future date.[122]

4.5.4 What is unclear is when the review will take place, and what is the baseline of project costs against which the actuals will be compared. By way of example, will the Board review any overspending/underspending until the end of the test period, as compared to the requested approval of $5.177M, or will it wait until the entire project is complete and compare the actual costs against the total $12.8 billion?

4.5.5 The importance of this is that OPG took the position at the hearing that if the actual total costs (whichever total is looked at) are equal to the approved total costs, there is no further prudence review.[123] This makes sense in the usual circumstances where a project is discrete.

4.5.6 This is not a normal capital project and a different process should be followed due to the magnitude of cost of the DRP. It traverses more than a decade, and over multiple payment amount applications. A problem arises if, for example, OPG incurs additional costs above those approved on Unit 2, but due to imprudent actions, and then underspends on subsequent units, so the total net variance is zero. In that case, OPG is never has to account for its imprudent actions. It would get a free pass. In fact, on OPG's view of the world, the Board and ratepayers would not even have the

[120] A1-2, p.4
[121] *Ibid*
[122] *Ibid*, p.5
[123] Tr.1:114

opportunity to determine if the overspending caused on Unit 2 was imprudent.

4.5.7 SEC submits the ideal approach for the Board is not to approve the total cost of the projects in the years they are brought in-service, but to approve discrete amounts related to each individual project. This would ensure that an overspending in one area cannot simply be offset by underspending in another area, without any review to ensure the former was prudent.

4.5.8 SEC recognizes approving 501 individual projects of the DRP is unreasonable, and may lead to unmanageable prudence reviews upon disposition of the CRVA. The more appropriate and reasonable middle ground is for the Board to individually approve projects as a bundle and by unit, and individually for the F&IP and SIO projects which are very discrete undertakings.

4.5.9 This would ensure that overspending in the Unit 2 RFR bundle is reviewed to ensure it was prudent, and that imprudent spending cannot be offset in other areas. It also would allow for discrete F&IP and SIO project reviews since, as the Board is aware, those projects have been plagued by problems so far.

4.5.10 This approach is similar to what the Board did in the EB-2012-0064 Toronto Hydro ICM Phase 1 Decision. In that proceeding, Toronto Hydro sought approval for hundreds of individual 'jobs' (i.e. what OPG calls a project) which it categorized by what it called 'projects' (similar to what OPG calls a bundle).[124] Instead of requiring reporting on each individual job, the Board required that it be done on a project (i.e. bundle) basis, so that "money cannot be used for a different project or to cover overspending on another project."[125] In contrast, the Board did "permit spending to be moved between the various jobs contained within a project".[126] The benefit of this approach is that it strikes a balance in allowing the Board's review to ensure that imprudence in one area is not being covered up by underspending in another, yet recognizing it is simply impractical to review every single job.

4.5.11 All of the information necessary to reach this level of granularity is already on the record. OPG has already reported, in numerous places, the Unit 2 cost information by bundle[127], and has listed the individual SIO and F&IP projects.[128] Providing a specific breakdown in one place, similar to the table OEB Staff recommended OPG provide in its submissions[129], would still be very beneficial, however. SEC proposes OPG be required to do this in its payment order process, so that parties have chance to review

[124] *Partial Decision and Order* (EB-2012-0064 - Toronto Hydro-Electric System Limited), April 2 2013
[125] *Ibid*, p.75
[126] *Ibid*
[127] For example, based on RQE estimate see D2-2-8, p.9. For U2EE estimate, see 4.3-Staff-055, Attachment 1, Appendix 2A
[128] D2-2-10, Tables 2-4
[129] OEB Staff Submissions, p.58-59, Table 13 and 14

the table to ensure its accuracy and completeness.

4.5.12 Giving any approvals on this basis would also allow a more detailed review of when and how the contingency is being used. Mr. Roberts testified that many regulatory commissions have required, on a quarterly or yearly basis, a line by line accounting of the use of contingency.[130]

4.6 ***LTEP/Off-Ramps***

4.6.1 SEC is concerned that OPG's DRP off-ramps are, in practice, illusory.

4.6.2 The 2013 Long-term Energy Plan ("LTEP") sets out a number of principles OPG is expected to follow with respect to the DRP project. Two important central principles are that OPG must "minimize commercial risk to ratepayers and the government" and that it must "mitigate reliability risks by developing contingency plans that include alternative supply options if contract and other objectives are at risk of non-fulfillment." [131]

4.6.3 One of the primary ways OPG has attempted to meet those requirements is by building into its major contracts off-ramps that allow it to cancel its contracts with vendors for convenience.[132] It has also unlapped the first and second refurbishment units so that they are not both out of service at the same time.[133] The benefit of this is to ensure that there is "full view of unit 2 execution" before the next unit (Unit 3) refurbishment begins[134], and to allow OPG to see how the work progresses before deciding if it will commit to a second and further units. [135]

4.6.4 A problem arises, though, since it is OPG's view that the "most complex period in the schedule" is at the end of the Unit 2 refurbishment.[136] This is where OPG has to "reintegrate the unit back into the operating plant; we move bulkheads; we energize systems; we bring things back into service; and then we do the commissioning and then need to confirm that everything we executed during refurbishment meets the standards and requirements and safety standards for the plant".[137] By this point in the refurbishment of Unit 2, it will have already had to make the decision to go forward with the next unit. The decision to move forward with the second unit (Unit 3) will need to be made long before it begins the most complex part of the refurbishment of Unit 2. If serious problems do arise, which is most likely in this part of the refurbishment, it will be too late for OPG to cancel the contracts or not continue with

[130] Tr.7:53
[131] Government of Ontario, *Achieving Balance – Ontario's Long Term Energy Plan*, December 2013 ("LTEP"), p.29
[132] D2-2-1, Attachment 2, p.1
[133] *Ibid*
[134] Tr.1:109
[135] Tr.1:171
[136] Tr.1:16
[137] *Ibid*

the next unit.

4.6.5 SEC submits this is a concern for ratepayers. OPG has not adequately built in provisions that allow it to trigger an off-ramp. The planning should not only have 'unlapped' units 2 and 3, but also inserted a significant window between the two. This would allow OPG to cancel the contracts with its vendors if problems arise right up until the completion of Unit 2. They did not do that and ratepayers are at risk.

4.7 ***F&IP and SIO Projects Performance***

4.7.1 In addition to the main refurbishment project bundles, OPG has included in the DRP a number of other projects that are being completed under two main categories: the Safety and Improvement Opportunities ("SIO"), and the Facilities & Infrastructure Projects ("F&IP").[138] The SIO projects are those that were required as part of the CNSC approval process. The F&IP are projects that OPG believes are prerequisites to the unit refurbishments.[139] These two categories of DRP work are significant. The SIO projects were forecast to cost $201.8M[140], and the F&IP project, $432.7M[141], between 2016 and 2021.

4.7.2 These two project groups present significant warning signs regarding the ability of OPG to execute the refurbishment on-time and on-schedule. The poor performance of many of these projects, that are prerequisites to the unit refurbishments, is concerning.

4.7.3 In fact, it would be an understatement to say that OPG has had problems with the SIO and F&IP projects. Of the projects that remain classified as DRP projects, the total variance from the original full project release is 53.8%, with some significant projects costing more than double their originally forecast amounts.

[138] D2-2-10, p.4
[139] *Ibid*, p.7
[140] *Ibid*, p.4, the sum of the amounts in line 15 and 16
[141] *Ibid*, p.7, the sum of the amounts in line 30 and 31

Project Name	Original Full Release Cost ($M)	EB-2016-0152 Cost ($M)	Variance
Facilities & Infastructure Projects			
D20 Storage Facility	110	381.1	246.5%
Water & Sewer Project	40.6	57.7	42.1%
Darlington Energy Complex	105.4	105.4	0.0%
R&FR Island Support Annex	40.7	40.7	0.0%
Refubishment Project Office	99.9	99.9	0.0%
Electrical Power Distribution System	16.8	20.8	23.8%
GM Office Facility	9.3	9.3	0.0%
Vehicle Screening Facility	3	6.6	120.0%
Safety Improvement Projects			
Third Emergency Power Generator	88.2	120.4	36.5%
Containment Filtered Venting System	80.6	80.3	-0.4%
Powerouse Steam Venting System	5.6	5.6	0.0%
Shield Tank Over Pressure Protection	13.5	13.5	0.0%
Emergency Service Water Buried Services	7.9	14.6	84.8%
Total	**621.5**	**955.9**	**53.8%**
Source: L-4.3-2 AMPCO-30, p.3			

4.7.4 Since some of these projects are not in-service yet, and continuing to have problems, it is likely the costs will increase further.

4.7.5 In OPG's March 2017 report to its Darlington Refurbishment Committee (a committee of its Board of Directors), it provided revised cost forecasts for a number of these projects. OPG now forecasts increased costs for each of the: the Third Emergency Power Generator, the Containment Filtered Venting System, and the Shield Tank Over Pressure Protection projects.[142] A total additional increase of $59.5M, or 10% for the projects originally forecast cost of $292.3M.

[142] J2.10, Attachment 1, p.16

F&IP and SIO Projects (March 2017 Update to DRC)				
Project Name	Original Full Release Cost ($M)	EB-2016-0152 Cost ($M)	March 2017 Report to DRC ($M)	Variance
D20 Storage Facility	110	381.1	381.1	0.0%
Third Emergency Power Generator	88.2	120.4	140	16.3%
Containment Filtered Venting System	80.6	80.3	101	25.8%
Shield Tank Overpressure Protection	13.5	13.5	32.7	142.2%
Total	292.3	595.3	654.8	10.0%
Source: J2.10, Attachment 1, p.16				

4.7.6 While it has not forecast a change in the D20 Storage facility cost yet, OPG knows it is still having significant enough problems that it removed it from the approvals being sought in this application.[143] OPG warns, in that same update to the Darlington Refurbishment Committee, that with respect to that project the "in-service date and estimate are at risk".[144] This is years after issues first arose which required the original contractor (Black & Macdonald) to be replaced by the Aecon SNC JV.[145]

4.7.7 This is consistent with the findings of the March 2017 Modus/Burns McDonnell Report, which continues to find problems with the F&IP projects. In addition to the D20 Project, the Third Emergency Power Generator and the Containment Filter Venting System "continue to miss targeted schedule dates and cost projections."[146] Thus the most recent forecasts of cost overruns on these projects - $362M, or 124% - is likely not the end of the bad news in this area.

4.8 ***Third Emergency Power Generator***

4.8.1 The Board should be very concerned about the escalating cost overruns of the Third Emergency Power Generator project. It is being managed by OPG's Project and Modifications group and the same concerns detailed in sections 5.3 and 5.5 of this Final Argument, apply equally. Originally forecast when approved by OPG to cost $88.2M[147], by the time the application was filed the amount was revised to $120M and to be completed in 2016.[148] Now, OPG has updated the in-service date to 2017, and update the forecast cost to $140M when completed.[149]

143 N2 Update
144 J2.10, Attachment 1, p.16
145 Tr.3:75
146 J2.10, Attachment 2, p.5
147 4.3-AMPCO-30
148 *Ibid*
149 J.2.10, Attachment 1, p.16; J2.6, Attachment 1

4.8.2 OEB Staff has proposed that the Board only approve the in-service additions for the project ($105.3M[150]) and not the updated $140M amount, and allow the difference to be recorded in the CRVA for review after the project is fully complete and a full prudence review should be conducted.[151] SEC agrees with this approach <u>but</u> believes the only amount that should be approved is the originally estimated amount of $88.2M. This would result in approval only of $73.5M.[152]

4.8.3 OEB Staff's approach would assume that the cost-overruns up until the $120M forecast were prudent. There is no basis to make that conclusion, in fact, similar to evidence regarding other projects that have now been moved out of the DRP project, those cost overruns are imprudent. Further, since OPG itself is proposing a similar review for the D20 project which has also had significant cost overruns, the Board can review both at the same time since they share similar issues (i.e. both managed by the P&M group).

4.9 <u>*It All Comes Down to Execution*</u>

4.9.1 OPG's expert, Dr. Galloway of Pegasus Global Holdings Inc., and the OEB Staff's expert, Mr. Roberts of Schiff Harden LLP, in many ways had similar evidence.[153] They both concluded that with respect to the planning of the DRP, OPG has met applicable industry standards. Both had high praise for the way OPG has gone about planning for this megaproject.[154]

4.9.2 This should not be much of a surprise. OPG has been planning for this project for about a decade and has spent over $2.2 billion dollars on definition phase work up until the end of 2015.[155] As the voluminous evidence shows, almost every conceivable independent third party has been retained to review some aspect of the planning, or been appointed to sit on some peer review board. OPG appears to have tried their best to put in place project controls, a risk management framework, and a schedule that will ensure completion on time and on budget.

4.9.3 All of this is a very positive sign. But it is only that. In no way does good planning guarantee successful execution.

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[150] D2-2-10, Table 2; OPG pre-filed evidence forecast $105.3M of in-service additions for the project in 2016. The project has in fact been delayed until 2017 (se J2.6, Attachment 1).
[151] OEB Staff Submissions, p.44
[152] D-2-10, Table 2 shows that at the time of the pre-filed evidence $120M was the forecast cost with $105.3M to go in-service in 2016 to align with the forecast completion date. No other amounts were forecast to go in-service during the test period. This would appear to indicate that $14.7 ($120M-105.3M) has been approved and gone in-service in the previous application. If this is correct than the incremental amounts that should go into-service in 2017 (new updated forecast as of J2.6, Attachment 1) is $73.5M which represents the difference between the original execution BCS amount of $88.2M and the $14.7M that has already been approved.
[153] D2-2-11, Attachment 2; M1
[154] Tr.7:14; Tr.6:30
[155] D2-2-4, p.2

4.9.4 As Mr. Roberts described it, "a project like this is really two halves of a coin. You have the planning phase and you have the execution phase."[156] Sufficient, even best practice, planning will only provide some comfort. Mr. Roberts put it best when he testified that "no amount of planning has a guarantee of successful completion to stay within budget for Unit 2 refurbishment and the overall DRP."[157] Planning is about creating a better opportunity to be successful in the execution phase.[158]

4.9.5 Even determining if the planning was sufficient can only truly be answered after the fact. The nature of these projects is that unless the third-party experts like Dr. Galloway and Mr. Roberts are going through each risk in the risk register, determining if they have all been identified and proper mitigation plans are in place, and reviewing the engineering designs and specifications, all you are getting is a review of the general planning process.[159]

4.9.6 This makes sense. However, it will not tell you if all aspects of the planning are prudent. Ratepayers and the Board will only know if the planning process was entirely prudent after the project is completed and if issues do arise, they can be traced back to how they were reasonably dealt with (or not) during the planning phase. Neither Dr. Galloway nor Mr. Roberts provided what amounts to an audit of the risk register to determine if each and every risk had been identified and the mitigation plan was appropriate. Issues may arise during execution which OPG should have identified and mitigated, and some that simply could not have been identified. We will only know after they materialize.

4.9.7 With respect to the cost, neither Dr. Galloway nor Mr. Roberts testified that the $12.8 billion amount is the correct forecast of costs.[160] Dr. Galloway looked at the budget planning and found that it was reasonable, but she did not do a line-by-line analysis of the costs.[161] Mr. Roberts was clear that doing so was beyond the scope of his mandate.[162]

4.9.8 Further, neither Dr. Galloway nor Mr. Roberts were asked, and so did not provide, a view on the significant cost overruns of the SIO and F&IP projects.[163] Thus, their views with respect to the definition phase planning for the DRP should in no way be considered an endorsement of the significant problems that have plagued these prerequisite projects.

[156] Tr.7:14
[157] Tr.7:13
[158] *Ibid*
[159] Dr. Galloway testified that she sampled the risk register but did not go line-by-line through it (See Tr.6:33)
[160] Tr.6:31; Vol.7, p.11
[161] Tr.6:32
[162] Tr.7:11,43
[163] Tr.5:33; Tr.7:81

4.10 ***Project Concerns***

4.10.1 ***Staffing.*** One of the major risks to the project's successful execution is the ability of both OPG and its contractors to staff the project. A megaproject like the DRP requires significant staffing resources. SEC is concerned that OPG has been unable to ramp up its required staffing needs for the DRP.

4.10.2 OPG's own resource needs for the project will require it to add an additional 1000 FTEs through 2017-2019.[164] The OPG requirements are just a small number compared to the additional employees that the contractors will require for their work.

4.10.3 In August of 2016, before breaker open on Unit 2, OPG was already behind in the level of staffing required.[165] While it has added FTEs since August, the latest evidence on the record is that by the end of January 2017, it was still 189 employees short, and was actually losing FTEs over the previous months.[166]

4.10.4 Mr. Roberts specifically identified staffing shortages as a critical risk in his report.[167] He reiterated his concern at the hearing.[168] And, when the updated information was brought to his attention, he fairly characterized it as "not good".[169]

4.10.5 These staffing issues are not new. Burns McDonnell/Modus have previously, in late 2015, expressed concerns regarding OPG's staffing resources.[170]

4.10.6 OPG tried to gloss over the staffing issue. While they are still below their plan for meeting the required headcount, they said they are "not at a place where we have a significant shortfall that introduces a complication for us in terms of managing the project."[171] OPG says that the forecasts were based on assumptions at the time and the resource plan is a "living plan".[172] Yet, when they provided the updated resource plan in J3.3, there appear to be essentially no changes to the approved plan.[173]

4.10.7 OPG relies on the ability to retain contractors, through purchased services, to supplement their resources if they are behind.[174] This may be a short-term solution but

[164] 4.3-AMPCO-087, p.3
[165] *Ibid*
[166] J3.3, Attachment 1
[167] M1, p.28
[168] Tr.7:74
[169] Tr.7:76
[170] D-2-2-8, Attachment 2, p.29
[171] Tr.3:31
[172] Tr.3:31
[173] See approved FTE in August 2016 version (4.3-AMPCO-087) numbers compared to those in Undertaking J3.3. The average monthly forecast in J3.3 is about the same as the 2017 monthly average in 2016 version. 2018 forecast monthly average numbers decrease by 11 FTEs.
[174] Tr.3:31

it is clearly not in the long-term interest of the project. If it was, then OPG would not hire additional FTEs for the project, as they are generally more expensive.

[redacted]

4.10.9 OPG has not adequately addressed its increasing resource management issue. It has not adequately staffed the project. Considering that OPG's responsibilities are primarily oversight and project management, there is a ripple effect down through the project if there is inadequate staffing on its part.

4.10.10 ***Contractors.*** [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted] [redacted]

DRP Contractor Value in Current and Previous Applications		
Vendor	**Value for which Approval is Sought in EB-2016-0152 or was received in prior applications ($M)**	**% of Total**
SNC/Aecon	1615	64.34%
Alstom	115	4.58%
GE Hatachi	23	0.92%
ES Fox	609	24.26%
Black & Macdonald	98	3.90%
BWXT/Candu	35	1.39%
BWXT	15	0.60%
Total	**2510**	
Source: J5.4, Chart 1		

4.11 *Major Contracts*

4.11.1 ***Contract Benchmarking.*** The largest of OPG's DRP contracts with its vendors are structured using target pricing mechanisms. The issue about the appropriateness of target pricing, as opposed to other mechanisms such as fixed price contracts, was canvassed thoroughly in the last proceeding.[194] OPG retained experts to review their contracting strategy, and those reports are on the record in this proceeding[195], including a follow-up report regarding the execution of the RFR contract.[196] Ultimately, determining if the negotiated contract is reasonable and cost-effective is very difficult exercise since there are no easy ways that allow the Board to compare the cost of the RFR bundle for the DRP with one done somewhere else. Each facility is unique because of its design, vintage and technology. More importantly, the scopes of work are usually very different.

4.11.2 What the Board can look at is the appropriate profit and overhead that is built into the target price contract compared to a broad benchmark of other nuclear projects. The

[redacted]

[194] See *Decision with Reasons* (OPG - EB-2013-0321), November 20 2014, p.61-64. While the issue was canvassed extensively in the decision, the Board explicitly determined that it would not provide any of the requested approvals for OPG's contracting strategy.
[195] For example, see D2-2-8, Attachment 4
[196] D2-2-11, Attachment 2

best information on the record with respect to that is the benchmarking exercise OPG conducted in 2010. In the lead up to preparing the RFP for the RFR project, OPG retained Faithful+Gould to benchmark, in part, the level of overhead and profit payable to contractors where target pricing had been used. [197]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[197] 4.3-SEC-14, Attachment 1, p.5; Tr.3:94

[redacted]

[redacted]

4.11.1 ***Contract Amendments and Productivity.*** [redacted]

[redacted]

[redacted]

[redacted]

4.11.5 ***Contract Risk.*** The Board should be very concerned about the possibility that OPG's execution of the project may go awry. The Board must do everything that it can do to ensure OPG executes the DRP on budget and on schedule. Unlike other major capital projects that the Board has approved over the years, the scope and cost of the DRP is so much larger, and the risks so much greater, that the potential negative impact for ratepayers is enormous.

4.11.6 OPG has used its contracts as a way to mitigate its own, and thus ratepayers risk, from project execution problems.[206] This is therefore a key area of concern.

4.11.7 OPG's overall contracting strategy is to ensure appropriate pricing models for each major work bundle that create what it believes is a reasonable risk model between itself and the contractor.[207] This means a range of target, fixed firm, and

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[redacted]

[206] D2-2-3, p.1-5
[207] *Ibid*

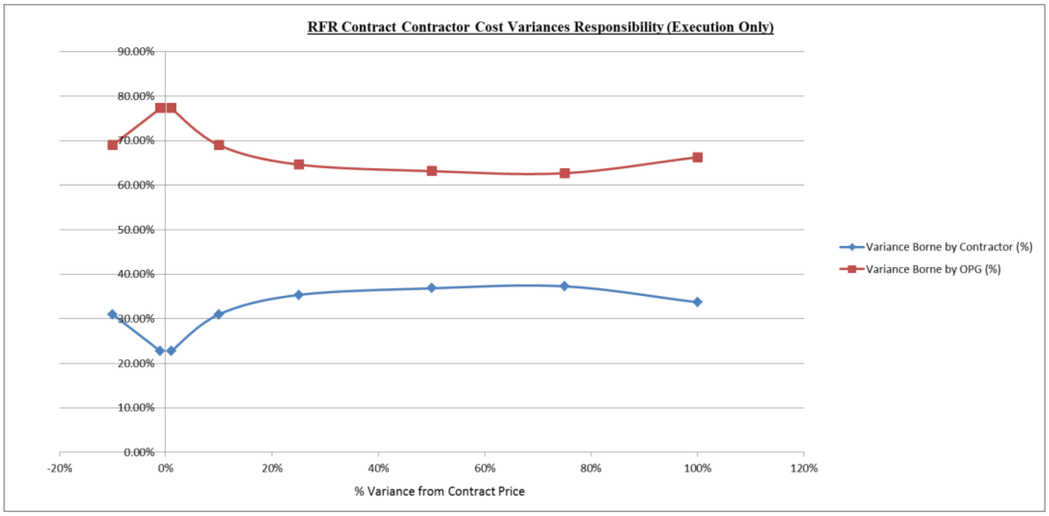
reimbursable/cost plus mark-up contracts. The most complex and uncertain work packages are primarily target price contracts.[208] As was discussed at length in the last payment amounts proceeding, this is because contractors were simply not willing to take on all the project risk through a firm/fixed price contract, or if they were, the cost would have been prohibitive and unreasonable.[209]

4.11.8 These negotiated contracts lead to a situation where, depending on the price and schedule overruns, OPG (and thus ratepayers, if the costs are found prudent) are picking up a disproportionate amount of any cost overruns. The specific contracts are all somewhat unique and have different components, but as demonstrated in the simplistic examples OPG provided in the evidence and in response to a number of interrogatories, ratepayers are paying the majority of cost overruns.

4.11.9 The RFR contract, which is by far the largest single contract, is a perfect example. Depending on the cost overrun amount, it will have different effects on what percentage is the responsibility of the Aecon SNC JV as opposed to OPG, but at no point does that amount ever reach anything close to half. OPG will be responsible for 62.7% to over 77% of the cost, for overruns between a 1% and 100% of the contract cost. [210]

RFR Contract Contractor Cost Variances Responsibility (Execution Only)									
	Cost Variance	Execution Phase Contract Cost ($M)	Contractor Cost ($M)	Cost Variance ($M)	Impact to Contractor ($M)	Impact to OPG ($M)	OPG Costs ($M)	Variance Borne by Contractor (%)	Variance Borne by OPG (%)
10% Savings	-10%	2159	1943	-216	-67	-149	2010	31.02%	68.98%
1% Savings	-1%	2159	2137	-22	-5	-17	2142	22.73%	77.27%
On Budget	0%	2159	2159				2159		
1% Cost Overrun	1%	2159	2181	22	5	17	2176	22.73%	77.27%
10% Cost Overrun	10%	2159	2375	216	67	149	2308	31.02%	68.98%
25% Cost Overrun	25%	2159	2699	540	191	349	2508	35.37%	64.63%
50% Cost Overrun	50%	2159	3239	1080	398	682	2841	36.85%	63.15%
75% Cost Overrun	75%	2159	3778	1619	604	1015	3174	37.31%	62.69%
100% Cost Overun	100%	2159	4318	2159	728	1431	3590	33.72%	66.28%
Source: D2-2-3, p.12-14; L-4.3-6 SEC 16									

[208] See for example RFR definition phase work, Turbine Generator EPC contract and the Fuel Handling contract. (D2-2-3, p.4)
[209] See record related to issue 4.11 in EB-2013-0321, specifically transcripts volumes 14 and 16.
[210] D2-2-3, p.12-14;



4.11.10 A similar breakdown of the responsibility for the Turbine Generator EPC contract, shows that OPG will be responsible for 63% to 74% of the cost overruns.[211]

Turbine Generator EPC Contract Contractor Cost Variances Responsibility								
	Cost Variance	Contract Cost ($M)	Total Contractor Cost ($M)	Cost Variance ($M)	Impact to Contractor ($M)	OPG Cost ($M)	Variance Borne by Contractor (%)	Variance Borne by OPG (%)
10% Savings	-10%	267	250	-26.7	-8.8	-17.9	32.96%	67.04%
1% Savings	-1%	267	264.3	-2.7	-0.7	-2	25.93%	74.07%
1% Cost Overrun	1%	267	269.6	2.7	0.7	2	25.93%	74.07%
10% Cost Overrun	10%	267	293.6	26.7	8.8	17.9	32.96%	67.04%
25% Cost Overrun	25%	267	33.7	66.7	24.1	42.6	36.13%	63.87%
Source: L-4.3-6 SEC 17								

4.11.11 Considering the history of megaprojects, and the way the contracts are structured, the chance of ratepayers being on the hook for very significant cost increases is material. OPG, as compared to its contractors, bears the brunt of those increases. It bears the risk of the cost overruns.

4.11.12 Except, of course, that it does not. The ratepayers ultimately bear the cost risk, not OPG.

4.12 ***Enhanced Reporting Required***

4.12.1 OPG has proposed to report on a number of metrics with respect to the DRP, to the Board, and presumably the public, on an annual basis.[212] It has also been putting up

[211] 4.3-SEC-17
[212] D2-2-9, p.9-10

certain status information on its website on a monthly basis.[213]

4.12.2 SEC submits that this information is wholly inadequate for a project of this size and scope. It does not provide the Board and the public with sufficient information to judge OPG's actual progress, monitor issues that may be arising, and most importantly, continue exerting pressure for the project to be completed on-time and on-budget.

4.12.3 OPG's proposed approach for reporting and monitoring of the DRP to the Board and the public is also out of step with the industry. OPG's view appears to be that simply because OPG has put in place a number of external oversight mechanisms that report to its board of directors and its shareholders, somehow means there should be less independent monitoring at the regulatory level.

4.12.4 Mr. Roberts testified that this view is the opposite of the trend within the industry.[214] Some regulatory commissions go as far as ordering an independent construction monitor to be put in place[215] and something like that is happening on a more frequent basis with many megaprojects[216].

4.12.5 Mr. Roberts provided a useful roadmap for what information OPG should be required to report on for the DRP in Undertaking J7.1. The purpose of the reporting requirements is to ensure that there is an adequate level of transparency for all stakeholders (OEB, ratepayers, general public, and the government):

> *"The overall benchmark of an effective OPG report to the Ontario Energy Board (OEB) and other governmental and/or regulatory stakeholders is that which provides sufficiently detailed and transparent information so that the recipients understand: (1) what is going on at the Darlington site including known and potential risks to budget and schedule; (2) the technical, commercial, schedule, safety, quality or other risk management challenges facing the DRP; and (3) the actions OPG is taking to mitigate risk, respond to issues as they arise, and make project management decisions."*[217]

4.12.6 SEC submits that OPG should be required to report using the guide in J7.1 on a quarterly basis to the Board and to the public. It will give the Board and all stakeholders an early warning signal if problems do occur. Most importantly, it provides the public on-going transparency of the most complex and expensive project OPG has (and likely will) ever undertake.

[213] Examples of that information was provided in K1.2, p.46-47
[214] Tr.7:122
[215] Tr.7:41
[216] Tr.7:67-68
[217] J7.1, p.6

5 NUCLEAR CAPITAL (Issues 2.1, 4.1-4.2, 4.4)

5.1 ***Overview***

5.1.1 OPG is seeking approval of $1,460M in 2017-2021 in-service additions for nuclear capital (excluding the DRP).[218] In addition, OPG is also seeking to add amounts to the opening 2017 rate base[219], including the 2016 (forecast) in-service additions of $497M.[220]

5.1.2 OPG has decided against updating its request for approval of proposed 2016 in-service additions to account for the significant variance from the forecast it filed in the Application,[221] and the actual in 2016. In 2016, OPG was only able to bring into service 58.8% of its forecast capital. It was unable to complete $205M worth of capital work.[222]

5.1.3 SEC has significant concerns regarding OPG's capital plan. It has a history of being over-budget and behind schedule on almost all of its capital work. The Board should make reductions going forward to ensure that OPG has an incentive to ensure that it does the amount of work proposed, and it does so on budget.

5.1.4 In addition, the Board should make specific disallowances to in-service projects that have gone over-budget due to OPG's mismanagement.

5.2 ***Rate Base***

5.2.1 Even though OPG has updated information regarding the annual in-service additions forecast for the test period that differs from the application, it has refused to update the requested relief.[223] The variance is primarily due to the in-service delays of projects forecast to enter service in 2016, in which it was unable to complete $205M worth of work, which represented 41.2% of its forecast [224]

5.2.2 The effect of OPG's position is that ratepayers will be overpaying in rates, and the company will be overcompensated. This is inappropriate.

5.2.3 OPG's position is that the original forecast nuclear operations capital is appropriate since over the 2016-2021 period, the total in-service amounts are materially the

[218] D2-1-3, Table 4
[219] OPG is also seeking approval of the difference between 2014-2015 approved in-service additions and actuals. (See D2-1-3, Table 4 for the variances).
[220] *Ibid*
[221] J21.1
[222] J14.1
[223] J21.1
[224] J14.1

same.[225] This may be the case, but it does not reflect the timing differences of the in-service additions. Timing matters with respect to in-service additions, as the sooner amounts are put into rate base, the greater the cost to ratepayers during the test period.[226]

5.2.4 While the total in-service addition amounts remain about the same, OPG has said there is an increase of about $8M in depreciation and amortization during the test period. OPG says this is due to change in project mix. OPG has filed no evidence to show that it has changed it capital plan since its originally filed evidence, and so there is no evidentiary basis for this. The Board must hold OPG to its own evidence, i.e. the projects it said it would do during the test period. No proposed changes to the project mix have been tested.

5.2.5 The Board should require OPG to update its forecast in-service additions to account for the 2016 actual in-service additions only. It should deny the cascading change that OPG says would occur, since as it has recognized it involves changing the project mix. While this may be a reasonable operational change as a result of having so much 2016 capital work delayed, the new mix was not tested during the proceeding, and should not be relied on by the Board.

5.2.6 Ratepayers should only have included in rates, amounts that are in-service. OPG's opening 2017 rate base should exclude the $205M of phantom 2016 additions.

5.3 ***Capital Plan***

5.3.1 OPG is forecasting to execute a very significant nuclear capital plan during the test year even when you exclude the DRP. It is forecast to bring into-service, on average, $291.9M per year over the test period, an increase of 36% compared to the previous 3 years (last payment amounts proceeding test period and 2016).

	Nuclear Operations Capital								
	2013	2014	2015	2016	2017	2018	2019	2020	2021
In-Service Additions ($M)	203.7	148.6	204.1	292	389	315.2	239.3	300.4	215.6
Source: J14.1									

5.3.2 SEC is concerned that OPG will not be able to execute on its capital program. Not only did OPG spend less than 60% of what it planned to spend in 2016, but the test period capital would be the largest ever spent on nuclear capital over a similar period of time.[227] Considering that OPG will be bringing in-service work that it could not complete as planned, it will likely create a domino effect where resources to do the 2016 work will push other projects from 2017 into 2018, and then other 2018 work

[225] J21.1
[226] OPG recognizes this by stating the total rate base during the period will be $31M higher based on its revised forecast (See J2.1).
[227] J14.1

will be pushed to 2019. Since the work is made up of larger projects, the effect likely will not be uniform shifts from year-to-year.

5.3.3 The larger concern is that if OPG brings into service the forecast amounts for which it seeks approval, it will not be for the same amount of work. OPG has a track record in its nuclear capital projects of being over-budget and behind schedule.

5.3.4 ***Always Over-budget.*** OPG's capital projects are, more often than not, over-budget. A review of all the nuclear capital projects that have gone in-service between 2014 and 2016 show that OPG's are 11.7% above the forecast cost set out in the first execution phase[228] business case summary ("BCS"). The problem is most significant in OPG's largest capital projects, its tier one category (greater than $20M), which are 41.8% higher than its first execution BCS.[229]

5.3.5 Based on how OPG presents its evidence, at first glance nobody would know the significant cost increases that have been occurring in its capital projects. OPG presents its variance analysis on the basis of what it calls its approved cost. Since OPG requires someone to approve all costs higher than forecast before they are spent, either by way of management, an over-variance approval, or a superseding BCS, the approved cost will always come in at or above the final in-service cost.[230] It is why OPG was able to respond to an interrogatory by saying "[t]here are no projects with actual or forecast costs that exceed approved costs".[231]

5.3.6 It is shocking that OPG does not appear to realize how misleading this is.

5.3.7 Comparing OPG's in-service capital costs to the budget in its first execution case BCS, tells a very different story. Over the last three years, OPG's final project capital costs are significantly higher than originally forecast.

Nuclear Operations In-Service Additions 2014-2016							
Projects	**Total Cost -First Execution Case BCS ($M)**	**Final Approved Cost ($M)**	**Actual/Forecast In-Service Cost ($M)**	**Variance to Final Approved Cost ($M)**	**Variance to First Execution Case BCS ($M)**	**Variance to Final Approved Cost (%)**	**Variance to First Execution BCS (%)**
Tier 1	163.6	250.9	232.1	-18.8	68.5	***-7.49%***	***41.87%***
Tier 2	171.4	199.9	172.3	-27.6	0.9	***-13.81%***	***0.53%***
Tier 3	119.9	126.5	103.8	-22.7	-16.1	***-17.94%***	***-13.43%***
TOTAL	**454.9**	**577.3**	**508.2**	**-69.1**	**53.3**	***-11.97%***	***11.72%***
Source: JT 2.16							

5.3.8 While OPG does not present its evidence in that fashion, it admits that this is how it

[228] The execution phase is the phase 4 of 5 of the nuclear project lifecycle. The last phase is project closeout and post implementation review. The first three are all related to planning: Project Identification, Project Initiation, and Project Definition. (See D2-1-1, p.3-4)
[229] Tr.14:59-60; JT2.16
[230] 4.4-SEC-46; Tr.14:57-58
[231] 4.4-SEC-46

tracks its own performance internally. It compares a project's final costs to its first execution BCS.[232] Based on the evidence of projects that have gone in-service during the previous test period, and up to December 31, 2016, OPG's performance has been poor. This poor performance is especially acute with its larger projects (tier 1) which ended up costing on average 41.87% more than the original execution phase BCS.

5.3.9 ***Always Behind Schedule.*** Not only are OPG's capital projects over-budget, they are behind schedule. Of the 24 nuclear capital projects above $5M identified in the last payment amounts application (EB-2013-0321) and forecast to go into-service in that test period (2014-2015), 21 were delayed, and only 4 were completed by the forecast in-service date.[233] On average, each went in-service, or was forecast to do so, 17 months after its originally scheduled.[234]

5.3.10 Of those 25 projects that were approved in the last payment amounts proceeding, all but one were in the execution phase at the time of the application and forecast. The only project that was in the early definition phase was only one month delayed.[235]

5.3.11 Considering that the last application had a test period of only 2 years, the Board can have absolutely no confidence in OPG's ability to forecast projects that will be completed over the much longer 5 year Application test period. When asked directly about this, OPG pointed to its new improved gating process in which it will be "looking at the schedule and ensuring the schedule that's laid out reflects the risks and the doable plan going forward."[236] OPG says, it will provide for a higher "confidence level that the projects that are started and the projects that are progressing forward will come in on the dates that we forecast going forward."[237]

5.3.12 SEC submits that this is not realistic. OPG's forecasting of in-service dates is not just slightly off. On average, it is wrong by almost a year and half. Simply having OPG improve the review process at each stage of project development is not going to correct what appears to be fundamental problems executing capital projects.

5.3.13 The effect of OPG's inability to bring projects in-service creates more than just a cascading affect from year to year, i.e. projects that come into-service late in one year, move into the next, forcing an equal amount of projects into the next year. If that were the case, we would expect the OPG forecast of in service additions over the longer term to be accurate.

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[232] Tr.14:60
[233] See D2-1-3, Table 7. 21 projects were late, 3 were early, and 1 was on-time.
[234] Tr.14:86; D2-2-3, Table 7. The average for all 25 projects is 16.9486 months.
[235] D2-1-3, Table 7. See Operation Support Building Refurbishment which has had its own extensive problems regarding cost.
[236] Tr.14:87
[237] *Ibid*

5.3.14 But this has not been the result to date. OEB Staff's submissions calculate the variance over the last 7 years between approved/budgeted nuclear operations to actuals as a difference of $190M.[238] OPG brought in 12.5% less capital than it has budgeted or were approved by the Board over those 7 years.[239]

5.3.15 ***Gated Process Will Not Solve All Issues.*** OPG has pinned most of the blame for its budgeting and scheduling issues on problems it previously had with properly determining which estimate class the project was in.[240] Its new gated process is supposed to correct for this by ensuring there is a more rigorous review of each class estimate. OPG plans on doing this, in part, by setting up a new organization within the company called the Centre of Excellence.[241]

5.3.16 SEC notes that the use of a gated process is not something new; it simply has never been properly implemented. OPG said it first began using the concept in 2012.[242] Its evidence in the last payment amounts proceeding, dated as far back as early 2013, references OPG having a 'Nuclear Projects Gated Process'.[243] It simply had not implemented it properly. In 2016, its own internal audit group found that the issue has been that the gating process outlined in OPG's own documents[244] has not been fully implemented.[245]

5.3.17 But even the new, more rigorous process OPG plans to bring to bear on its capital projects will only affect <u>some</u> of the projects that are expected to go in-service in the test period. The Centre of Excellence is only expected to be fully operational by mid-year 2017.[246] The new gated process only began to be implemented in mid-2016, and only with a few larger projects.[247] Of the 35 tier 1 projects ($20M or greater) identified in the evidence that have an approved BCS, only 4 have gone through the new gated process.[248] Since the gated process is focusing right now on the larger projects, it is doubtful if any tier 2 or 3 projects have gone through the new gated process. This is <u>after</u> OPG management told its internal auditors that it would have the process in place by Q1 2016.[249]

5.3.18 The impact of inaccurate cost and schedule forecasts is significant. OPG's internal

[238] OEB Staff Submissions, p.20, Table 8
[239] *Ibid.* 12.5% = -$190M over the total approved budged of 1532M.
[240] Tr.14;65; Tr.14:105
[241] Tr.14:99; J15.3
[242] Tr.15:18
[243] See for example EB-2013-0321, D2-2-1, Attachment 4-2, p.7
[244] 'Nuclear Projects governance' and 'Project Management Manuel' (See J7.3, Attachment, p.11)
[245] J7.3, Attachment 1, p.11
[246] Tr.1:20
[247] Tr.14:110
[248] J15.7 identified 4 projects that have gone through the new process of those identified in the 35 projects contained in 4.2-AMPCO-17, Attachment 1.
[249] J7.3, Attachment 1, p.11

audit identified it as a high risk issue.[250] The impact includes inaccurate cost-benefit analysis which results in going forward with the project but picking what may not be the best option.[251] It also may result in deferrals or cancellations of other projects downstream due to insufficient allocation of resources.[252] Moreover, it will lead to unnecessary cost increases and schedule delays due to insufficient oversight and control at the correct stages of project execution.[253]

5.3.19 This means that the vast majority of projects whose costs and schedules have been forecast and included in the applied for in-service additions, will not be correct. The Board can expect projects to continue to be over-budget and behind schedule. This means OPG will either overspend compared to its budget or, more likely, do fewer projects. Neither scenario is good for ratepayers.

5.3.20 Internal audits show imprudent spending and OPG's project management issues go even deeper. The internal audit group controls audit of OPG's Project Modification Group, that has responsibility over most nuclear capital projects and OM&A[254], found, in addition to the gating problems, issues with its ability to measure cost and schedule performance.[255] The audit found that of the 13 projects sampled, 5 did not meet the requirements for project changes being approved in BCS or the Project Change Request Authorization Forms.[256] OPG estimates that the impact is potential cost and schedule increases, as the information is needed for Cost and Schedule Control Baselines which are the "primary control mechanism to manage and control cost and schedule performance on a project"[257]

5.3.21 Another nuclear oversight audit of its project management conducted a year earlier (2015) by OPG's internal audit group showed a host of other issues.[258] It found that the P&M group was not executing key project management oversight activities despite clear deficiencies in project management, contract management, and filed engineering at Pickering, Darlington and Nuclear Waste.[259] These issues have caused "project delays, cost overruns, quality issues, and some safety concerns."[260] The audit also found that the project management staff "do not have sufficient training and familiarity with good project management practices and fundamentals".[261] This also

[250] *Ibid*, p.7
[251] *Ibid*
[252] *Ibid*
[253] *Ibid*, p.11
[254] The Project & Modifications Group is responsible for management and execution of project OM&A and most capital projects for Darlington, Pickering, and the Western Waste Facility (See Tr.14:96-97)
[255] J7.3, Attachment 1, p.9
[256] *Ibid*
[257] *Ibid*
[258] JT1.8, Attachment 2
[259] *Ibid*, p.3
[260] *Ibid*
[261] *Ibid*, p.7

contributed to project cost increases and schedule delays.[262]

5.3.22 Burns & McDonnell/Modus, in the Q2 2014 report, made what can only be described as disturbing findings regarding OPG's P&M Group. The findings included:

(a) In a self-assessment by OPG's own staff, their views of P&M managers included comments such as "[d]evelopment and use of Risk Register is seen as purely administrative and not adding value for the Project Managers."[263]

(b) Risk management training was not just insufficient but had gotten worse.[264] They commented that "risk management training is virtually non-existing in the P&M organization in distinct contrast to several years ago when quarterly workshops were regulatory conducted."[265]

(c) P&M did not actively manage risks, "[based] on [Burns & McDonnell/Modus] observations, it appears that all P&M's identification of risks is a 'check-the-box' activity due to the fact that having a list of risks is a pre-requisite to obtaining funding release.[266]

(d) P&M has an improper bidding and estimate process. Burns & McDonnell/Modus found in interviews with OPG staff and contractors that "initial BCS estimates were poorly characterized as <u>part of a deliberate management strategy directed by the former VP of P&M</u>" [emphasis added].[267] It found that the ability to execute the work was given essentially no consideration:

> *"P&M gave only token consideration to determining which contractor had a better approach for executing the work. P&M chose the "low bidder" even though the other contractor's qualifications and project approach were viewed more favorably. Thus, P&M created the conditions for a perfect storm of cost and schedule overruns. Because the work is largely based on a cost-reimbursable target price with no caps on size, P&M's artificial beating down the contractors' prices in the bid phase was a Pyrrhic victory: P&M's actions did not reduce cost and only served to deprive senior management of realistic cost projections for this work. The budgets for these and other F&I projects were*

[262] *Ibid*
[263] 4.3-Staff-72, Attachment 4, p.8, Citing NR Management System Oversight group (SA RF13-00855 dated January 20 2014)
[264] 4.3-Staff-72, Attachment 4, p.8
[265] *Ibid*
[266] *Ibid*
[267] *Ibid*, p.7

> *nothing more than paper barriers that were easily surmounted as the design work continued to generate more complex (and expensive) work."*[268]

(e) P&M did not effectively react to problems when they materialized, and did not accurately and timely report the extent of cost overruns, schedule delays and scope increases to senior management.[269] This had the effect of depriving management of the ability to, among other things, "stop the design changes that led to these increases", "[s]top the project entirely and resort to one of the other evaluated options, or "mitigate the impact of the schedule delays and overruns."[270]

(f) P&M failed to establish accountability standards for the contractors.[271]

5.3.23 The issue is not simply one of an inaccurate baseline cost, as OPG argues, and that the final costs reflect the true costs (i.e. had the project been properly estimated originally).[272] The opinions of OPG's own internal audit group and its own independent oversight contractors Burns & McDonnell/Modus are that the inaccurate baselines and project management problems in the P&M group have caused increased costs that otherwise would not have been incurred if the correct baseline had been used. Inaccurate baseline costs cause a range of problems including, but not limited to, hampering proper project management[273], causing the misallocation of resources[274], and in some cases leading to unqualified contractors being chosen[275].

5.3.24 OPG's own witness recognized that not having the proper baseline can lead to cost increases that otherwise would not have occurred:[276]

> *"MR. RUBENSTEIN: And I understand that's what you're doing on a go-forward basis. I am just trying to understand, I read this as these documents said you were to have this process, it just wasn't implemented with AISC; is that correct?*
>
> *MR. LAWRIE: Some projects didn't have all the documentation they should have had.*

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[268] *Ibid*, p.7-8
[269] *Ibid*, p.7
[270] *Ibid*, p.11
[271] *Ibid*, Attachment 4, p.7
[272] Argument-in-Chief, p.28
[273] 4.3-Staff-72, Attachment 4, p.11; JT1.8, Attachment 2, p.7
[274] J7.3, Attachment 1, p.11
[275] 4.3-Staff-72, Attachment 4, p.7-8
[276] Tr.14:111-112

> *MR. RUBENSTEIN: And if we look at the impact, the impact of when this occurs is potential for cost increases and schedule delays due to insufficient independent oversight and control of project activities and objectives.*
>
> *MR. LAWRIE: There is risk without having a solid base line, yes.*
>
> *MR. RUBENSTEIN: So how do we know that the table you showed me before, with the superseding business cases, projects going in-service or have already gone in-service, this isn't the reason why there's the cost increases, that OPG just didn't implement the process that its own documents said it should have.*
>
> *MR. LAWRIE: As I mentioned earlier, these wouldn't directly contribute to increased cost of a particular pump installation, or the cost increase to a particular design. What it would do is give us a late indication that the project is performing off plan, not having a solid base line to compare current performance to.*
>
> *MR. RUBENSTEIN: I would assume earlier indication allows you to minimize cost issues, correct?*
>
> *MR. LAWRIE: It has an opportunity to minimize impact.*
>
> *MR. RUBENSTEIN: And because you didn't do that, the costs may have been higher than they otherwise would have been.*
>
> *MR. LAWRIE: It's possible". [emphasis added]*

5.3.25 The problems with the P&M group do not just have an effect going forward. They are also a key reason that projects have gone over-budget. While Burns & McDonnell/Modus was doing oversight for the DRP, and specifically at that time for the F&IP projects, the P&M group primarily managed non-DRP nuclear capital work.[277] In that report, Burns &McDonnell/ Modus examined five separate projects and found that each exhibited, to differing extents, the issues identified.[278] One of those included the now re-classified Auxiliary Heat System project.[279]

5.3.26 The issues identified, and the various audit reports, are more than just ordinary issues that arise in capital projects. They are a clear indication of imprudence by OPG. They are a good explanation of why OPG's capital projects are significantly over-budget and behind schedule. OPG's view that even with the final costs over forecast, and the

[277] J8.3, Attachment 1, p.3; Tr.14:96-97
[278] 4.3-Staff-72, Attachment 4, p.7
[279] *Ibid*

significant shortcomings detailed, "[t]he actual work that's performed is value added work, those are the prudently incurred costs."[280] Such a position is simply contrary to the evidence in this proceeding. It is clear that the incremental costs for a number of projects that went into service over-budget since the last test period are imprudent, and should not be recovered from ratepayers. SEC discusses the specific projects in section 5.5.

5.3.27 ***Contractor Issues.*** [redacted]

5.3.28 ***Work Management Benchmarking.*** Two new industry benchmarking metrics are scope stability[285] and schedule adherence.[286] These metrics measure OPG's work management, and are benchmarked with other participants by the Institute of Nuclear Power Operators ("INPO").[287]

Work Management Benchmarking (Annual Avg. %)							
Scope Stability	2012	2013	2014	2015	2016	Top Quartile	OPG Target
Darlington	79	74.5	65.25	72.25	73.75	92	80
Pickering	57.75	57	63.5	68.25	68	92	75
Schedule Adherence	2012	2013	2014	2015	2016	Top Quartile	OPG Target
Darlington	88.75	89.25	86.25	86.75	88.25	95	95
Pickering	88	86.5	86	87.25	88	95	91
Source: J14.5							

5.3.29 OPG's results show that while Pickering has improved, Darlington's scope stability has generally gotten worse over the years. Not only are these results way below the top

[280] Tr.15:132. OPG's view throughout appears to be that if they actually spent incremental dollars, those costs must be prudent, because that how much it actually costs. This tautology is clearly not the test for prudence.
[redacted]
[285] Scope stability tracks the amount of work that stays on schedule eight weeks out before execution of an individual task. (Tr.14:110; J14.5.)
[286] F2-1-1, Attachment 3, p.12
[287] *Ibid*; J14.5

quartile of 92%, they are also below OPG's own target of 80% for Darlington and 75% for Pickering.[288] The importance of scope stability is "critical to successful completion of a work management program because scope additions or changes will lead to schedule delays and failure to complete schedule tasks."[289]

5.3.30 Regarding schedule adherence, there has been little change in performance, and certainly no continuous improvement. OPG still benchmarks not only below the top quartile of 95%, but below its own targets of 95% for Darlington and 91% for Pickering.[290]

5.3.31 SEC submits there is an undisputed link between OPG's performance on these capital work management metrics and its problems with capital costs and schedule. Scope changes undermine the ability to properly manage capital projects, which adds costs and delays. In fact, as discussed previously in this Final Argument, OPG's problems with cost and schedule control baselines, as revealed in the internal audit reports, have a significant negative impact on project performance.[291]

5.4 ***Insufficient Productivity.***

5.4.1 OPG has not incorporated sufficient productivity into its nuclear OM&A and capital budgets. More broadly, it simply has not undertaken sufficient productivity indicatives for its 5 year test period. In its pre-filed evidence, OPG has listed a number of productivity initiatives it has taken in its OM&A program.[292] There is no similar set of productivity initiatives that target OPG's significant nuclear capital budget.

5.4.2 OPG's evidence is that most of the outputs of the initiatives are not about lowering costs, but about increasing production.[293] OPG has stated that of the 7 listed initiatives, the only one that focuses on costs is inventory reduction.[294] The reason for this focus is OPG's historic issue of meeting its own production forecast:

> *"MS. CARMICHAEL: The initiatives we built into the business plan focus predominantly on production because that is our highest risk area, as we've seen. So most of our initiatives are around ensuring we meet our production targets, not necessarily saving OM&A."*[295]

5.4.3 OPG's plan to put in place initiatives to meet its production forecast is important, but so is focusing on costs. This is because while production may be the company's

[288] J14.5
[289] *Ibid*
[290] *Ibid*
[291] J7.3, Attachment 1, p.9
[292] F2-1-1,p.18-21
[293] *Ibid*; Tr.14:10-11
[294] Tr.14:11
[295] Tr.14:1011

highest risk, that may not be equally true for ratepayers. Payment amounts are determined based on approved forecast costs and production forecasts. If OPG does not meet its production forecast, it generates less revenue. Ratepayers do not bear that cost, except insofar as the replacement generation costs more. On the other hand, ratepayers do bear the consequences of high OM&A and capital costs. That is why it is important for ratepayers that OPG also focus on costs.

5.4.4 SEC submits additional cost focused productivity initiatives should have been planned and built into the capital budget for the test period. It is not sufficient to simply overlay a stretch factor, which to be clear OPG is not even proposing for capital. An amount should be built into the base budget to reflect what OPG should be undertaking and planning now. The stretch factor represents additional incremental efficiencies that OPG should be seeking in each subsequent year of its test period that it cannot plan or forecast now. It is too encourage continues improvement by requiring OPG year over year to find additional efficiencies.

5.5 ***Specific Project Issues***

5.5.1 ***Operations Support Building Refurbishment.*** OPG is seeking approval for the incremental in-service additions for the Darlington Operations Support Building Refurbishment ("OSB"). The project was re-classified from the last payment amounts proceeding, where it was considered part of the DRP.[296] OPG's in-service additions for the OSB were $55.1M in 2015 and $3.6M in 2016, with the final amount expected to be $62.7M when the entire project goes in-service.[297] This is a significant increase over the forecast of $45.1M approved in the last payment amounts proceeding.[298]

5.5.2 SEC submits the Board should deny approval of at least half of any incremental amounts for the OSB, as they were not prudently incurred.

5.5.3 OPG claims that the variance is primarily due to completing the forecast before the detailed engineering had been completed.[299] SEC agrees that this is likely a significant factor, and *some* of the incremental costs would have been incurred regardless, but even that does not mean that the costs are prudent. Considering the P&M group was also responsible for the project, and considering the comments made by the internal audit group and Burns &McDonnell/Modus, the same negligent management issues almost certainly occurred with this OSB project. OPG's own senior management noted in handwriting on the project over-variance approval itself that "[t]his is poor performance".[300]

5.5.4 OPG's entire P&M group who managed this project acted entirely imprudently, as the Burns &McDonnell/Modus findings show. Ratepayers should not have to be

[296] 4.3-AMPCO-30
[297] *Ibid*
[298] D2-1-3, p.10; EB-2013-0321, D2-2-2, p.6 (as updated on 2014-07-02)

responsible for all the incremental costs because of OPG's mismanagement. The Board should disallow $8.8M, which is 50% of the incremental $17.6M for the project.[301]

5.5.5 ***Auxiliary Heating System Project.*** The Auxiliary Heating System ("AHS") project involves replacing the end of life boiler house at Darlington. In the previous proceeding, OPG updated the forecast total project cost to $85.1M, up from $45.6M[302], with $75.3M forecast to go in-service in 2015.[303] Similar to the OBS, the project was also re-classified since the last payment amounts proceeding from DRP to nuclear capital.[304] The costs since have increased an additional $14.4M to $99.5M.[305] SEC submits the additional costs should not be recoverable from ratepayers. They are imprudent.

5.5.6 The AHS project was one of the specific projects discussed by Burns &McDonnell/ Modus in its Q2 2014 report that was so critical of OPG's P&M group. The problems they identified are all clearly documented with the AHS project. OPG's argument that the cost overrun is simply a baseline costing issue[306] *may* have had some relevance to the increase of costs from the original $45.6M to the approved 2015 in-service amounts in the last case of $75.3M, but not with respect to the further cost overruns.

5.5.7 In its reply argument in the last proceeding, OPG made the same argument it has made in this proceeding regarding the cost overruns for the AHS project.[307] The argument is no longer a credible excuse for the further cost overruns since the last application. It is more likely the cost overruns are the fault of the identified P&M mismanagement that continues through the 2016 internal audit reports.

5.5.8 The Board should reject the incremental costs, i.e. those project costs that have not been approved previously.

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[299] Argument-in-Chief, p.28
[300] D2-1-3, Attachment 1, Tab 1, p.5
[301] $17.6M incremental amount is based on the OPG's forecast final costs are $62.7M and the original approved amount of $45.1M.
[302] EB-2013-0321, D2-1, Table 3, Line 3
[303] D2-1-3, p.9
[304] 4.3-AMPCO-30
[305] D2-1-3, p.9. OPG testified during the hearing that the costs are now closer to $107M (Tr.15:135-136)
[306] At footnote 11 on p.28 of its Argument-in-Chief, OPG references the Burns &McDonnell/ Modus 'Supplementary Report to Nuclear Oversight Committee – 2nd Quarter 2014, found at JT15.4 , Attachment 1, p.3 for the evidence that the original cost estimate if done correctly for the AHS would have been close to the actual cost of the project at the time. First, SEC notes the report does not make that finding at all. Second, the supplementary report needs to be put in the proper context. The report was commissioned after the first report was commissioned which required a suspension of the last payment amounts decision while OPG filed additional evidence. In fact, as shown in EB-2013-0321 JT3.8, OPG's management and counsel had provided extensive comments to Burns &McDonnell/ Modus regarding what should and should not be in their report, and what language should be used. The independence of the supplementary report was and is put into question.
[307] EB-2013-0321, OPG Reply Argument, p.86

5.6 ***Summary***

5.6.1 SEC submits the Board should reduce the forecast in-service additions in each year of the test period by 12.5%. There are two independent reasons for why this is an appropriate annual reduction to make.

5.6.2 First, this represents the 2010 to 2016 average variance between approved/budget in-service additions and actual in-service additions.

5.6.3 Second, it is close to the 11.72% which is the average cost overrun of OPG's capital projects. OPG is likely to have to do the work even if goes over-budget, but it will do less of other work during the test period to make up the difference. Since what is being approved is a single total in-service addition amount and not individual projects, an amount that reflects the value of what is likely to be happen (same amount of in-service capital but less work) is not appropriate and adjustment should be made.

5.6.4 The Board should also make a reduction to forecast in-service additions to account for OPG's complete lack of efficiency and productivity initiatives in its test period capital plan.

5.6.5 With respect to specific projects, the Board should disallow 50% of the incremental costs of the OBS, and disallow the entire incremental amounts for the AHS project, in aggregate $23.2M.

6 PRODUCTION FORECAST (Issue 5)

6.1 ***Nuclear Production Forecast***

6.1.1 No submissions.

7 OPERATING COSTS (Issue 6)

7.1 *Nuclear OM&A (Issue 6.1)*

7.1.1 ***Overview.*** OPG is also seeking approval of $8,102.6M in nuclear OM&A during the test period.[308] This is, on average, an increase of 2.5% over 2016 actuals. While the year-over-year increases may not appear to be very significant, the baseline is high and reflects OPG's on-going struggle to operate an effective and efficient nuclear organization. A deeper look at the underlying amounts, specifically as it relates to lack of productivity, staffing, compensation, and benchmarking, shows that they still remain unreasonable.

7.1.2 OPG's forecast OM&A during the test period is also occurring during a time where customers are getting less, but still paying more. OPG's refurbishment will require units to be offline during the test period, and yet the direct costs for those units are not expected to decrease.[309] This is counter-intuitive, but it is what OPG forecasts.

7.1.3 ***Insufficient Productivity.*** OPG has not incorporated sufficient productivity into OM&A. OPG has not specified the savings that will be attributable to the initiatives during the test period, even though its business plan is based on their successful execution.[310]

7.1.4 For the same reasons set out in section 5.4, SEC submits an additional amount for productivity and efficiency savings should be built into the test period budgets, to reflect initiatives that it should be undertaking.

7.1.5 ***Fitness For Duty.*** In OPG's first Impact Statement it updated its OM&A request to include $41M over the test period for the CNSC's Fitness for Duty program.[311] The bulk of the program that the CNSC has proposed is for random drug and alcohol testing for employees working at nuclear facilities.[312] SEC submits the Board should not approve additional funding for this program, for two major reasons.

7.1.6 First, for most years in the test period, the amount is not material using OPG's own materiality threshold.[313]Using the updated materiality threshold as proposed in section 10.9 of this argument, the amounts never rise to that level. The Board should not allow

[308] Argument-in-Chief, p.73; J14.2, Attachment 1;
[309] 6.1-Staff-89
[310] 6.1-SEC-15
[311] N1-1-1, p.5; Tr.13:109
[312] See K15.5, Human Performance Management: Fitness, Draft CNSC REGDOC 2.2.4
[313] The proposed annual amounts are 2017: $0.5M, 2018: $0.5M, 2019: $16.7M, 2020: $11.7M, 2021: $11.7M (N1-1-1, p.4). OPG's position is its materiality threshold is $10M. Based on J8.1, an updated materiality threshold used by electricity distributors of 0.5% of their revenue requirement it would be $16.8M. Even if the Board uses the same methodology approved EB-2007-0905, only in 2019 would the amount reach the materiality threshold since the materiality threshold is $14.4M as shown in J8.1

OPG to update its request during the Application for non-material amounts, especially when there has been no change in circumstances since the filing of the Application. The CNSC's draft Fitness for Duty program was released long before the original Application was filed, and interested parties, including OPG, had provided detailed comments to the CNSC already.[314] Nothing has changed in the CNSC's process since the Application was filed.

7.1.7 Second, there is a strong likelihood that the program will either not go ahead or at the very least be significantly delayed. A review of the comments on the CNSC website shows that almost all relevant stakeholders have very significant concerns about the program.[315] Those concerns include its legality.[316] The stakeholders' comment period ended over a year ago, and the issue has not yet been brought to the commission for a decision.[317] An issue like this which touches on constitutional rights will likely be appealed, even if approved.

7.1.8 At the oral hearing, OPG claimed that it had a discussion with the CNSC through informal communications which had led them to believe that it will be implemented.[318] Yet, when asked to provide the written communications, they show that no such opinion was given.[319] In fact, the communications discuss how there have been delays bringing the issue to the commission itself.[320]

7.1.9 The Board should not approve at this time funds for the proposed Fitness for Duty requirement. At the very least, it should include a variance account, to ensure ratepayers do not pay for this or any other forecast regulatory requirement that is not ultimately implemented in the test period.

7.2 ***Nuclear Benchmarking (Issue 6.2)***

7.2.1 Annually, OPG conducts benchmarking of its nuclear facilities against industry peers in a wide range of metrics. It has done so since its second payment amounts proceeding (EB-2010-0008) after being ordered to do so by the Board in the first payment amounts proceeding (EB-2007-0905). Benchmarking is a required feature not just for the Board, but also OPG's shareholder, which included benchmarking in its Memorandum of Agreement.[321] The annual benchmarking requirement was

[314] See K14.1, p.116
[315] See http://nuclearsafety.gc.ca/eng/acts-and-regulations/regulatory-documents/history/regdoc2-2-4.cfm. Also see OPG's comments on the record at K13.1
[316] K13.1, p3
[317] See status of the matter at http://nuclearsafety.gc.ca/eng/acts-and-regulations/regulatory-documents/history/regdoc2-2-4.cfm.
[318] Tr.13, p.122
[319] J13.5, Attachment 1
[320] J13.5, Attachment 2
[321] A1-4-1, Attachment 2, section 6.1.3

reaffirmed by the Board in its last payment amounts decision.[322]

7.2.2 OPG's worsening benchmarking performance reinforces the need for the Board to reduce OPG's proposed test period OM&A.

7.2.3 OPG's Memorandum of Agreement with its shareholder, the Province of Ontario, has changed since the one in place through the previous three payment amounts proceedings.[323] It no longer explicitly states that OPG is required to benchmark "against the top quartile of private and publicly- owned nuclear electricity generators in North America."[324] While it also does not use the same language that its "top operational priority will be to improve the operation of its existing nuclear fleet"[325], OPG's witness, Ms. Carmichael, did confirm that still is a top priority, and that OPG still seeks continuous improvement in its nuclear operations.[326]

7.2.4 In the last payment amounts proceeding, the Board found that not only was OPG's performance in the three key metrics (WANO NPI, 2-Year Unit Capability Factor, and 3-Year Total Generating Costs Per MWh) not in the top quartile, but it also did not demonstrate continuous improvement:

> *"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 ratepayers would expect. OPG is not satisfied with its performance either: "… clearly we would like to see better performance from our plants.""*[327]

7.2.5 OPG's nuclear benchmarking performance has not improved. In fact, it is getting worse, and is expected to continue to slide during the test period.

7.2.6 OPG's performance at Pickering has remained steadfastly in the bottom quartile from 2012-2015. For Darlington, its unit capability factor has moved from the top quartile in 2012 to the bottom quartile in 2015. Its 3 year rolling Total Generating Cost per MWh metric has also significantly increased in 2015, and now is no longer in the top quartile but at the median.[328]

[322] *Decision with Reasons* (EB-2013-0321 – OPG 2014-2015), November 20th 2014, p.45
[323] *Ibid*
[324] *Decision with Reasons* (EB-2013-0321 – OPG 2014-2015), November 20th 2014, Appendix C, section 2
[325] *Ibid*; Tr.13:14
[326] Tr.13:14
[327] *Ibid*
[328] While OPG in its Argument-in-Chief says that it is in the second quartile (p.81, Ln 4), it was more accurately right at the median. (See 6.2-SEC-63, Attachment 2, p.5). The median was $44.38/MWh, OPG was 44.38/MWh.

7.2.7 OPG's rationale for its poor performance for Darlington in the important Value for Money metric of Total Generating Costs Per MWh ("TGC/MWh") is that it undertook a Vacuum Building Outage ("VBO").[329] SEC recognizes that this will push costs up, but clearly that cannot be the main reason for the significant increase. The metric is a 3-year rolling average, which would include the 2013 and 2014 years as well, yet the metric went up from $37.73 to $44.38 in one year alone. The annual target amount is actually increasing over the test period. If it had only been the 2015 VBO that increased the 3 year rolling average by such an amount, one would expect to see the 2016 and onward annual targets to be lower, not higher.

Nuclear Benchmarking Results				
	2012	2013	2014	2015
Darlington				
WANO NPI (Index)	96.3	90.80	*91.20*	83.70
2-Year Unit Capability Factor (%)	92	90.44	89.41	83.96
3-Year Total Generating Cost ($/MWh)	31.67	34.42	37.73	44.38
Pickering				
WANO NPI (Index)	64.7	67.5	64.3	68.5
2-Year Unit Capability Factor (%)	75.62	75.77	74.5	77.32
3-Year Total Generating Cost ($/MWh)	67.16	67.18	67.93	67.36
1st Quartile				
4th Quartile				
Source: K12.4, p.18				

7.2.8 OPG's annual targets do not show any continuous improvement going forward. OPG's expectations are that for Darlington, its WANO NPI Index will decrease in 2017, before rising again in 2018 and 2019. Meanwhile, its Unit Capability Factor will decrease, and its TGC/MWh will increase up until 2021. This is <u>after</u> OPG's proposed "normalizing" methodology to account for the DRP.

7.2.9 Pickering also does not show any sign of improvement. Its WANO NPI index is expected to decrease. It has no plans to improve its Forced Loss Rate, and it is expecting a decrease in its Unit Capability Factor. Its cost is also expected to rise significantly through the test period on a TGC/MWh basis.

[329] Argument-in-Chief, p.81

Annual Nuclear Operations Targets	2016	2017	2018	2019	2020	2021
Darlington						
WANO NPI (Index)	87.3	83.1	90.7	91		
Forced Loss Rate (%)	1	1	1	1	4.2	3
r Unit Capability Factor (%)	91.1	85.1	86	87.8	79.4	90.9
Normalized Total Generating Cost ($/MWh)	47.35	49.75	49.54	52.33	52.04	39.8
Pickering						
WANO NPI (Index)	72.3	69.7	67.2	65.9		
Forced Loss Rate (%)	5	5	5	5	5	5
Unit Capability Factor (%)	77.6	71.5	72	72.6	73.4	70.6
Normalized Total Generating Cost ($/MWh)	71.09	78.83	80.09	81.49	74.93	81.16
Source:						
2016-2019: 2017-19 Business Plan, N1-1-1, Attach 1, p.24						
2020-2021: F2-1-1, p.16						

7.2.10 What is even more surprising is that, with respect to the 2017 through 2019 annual targets, they are actually worse than originally proposed. OPG updated its annual targets in its 2017-2019 Business Plan, and they are worse than what was originally proposed in the Application, which was based on the 2016-2018 Business Plan.[330]

7.2.11 Further, OPG almost never meets its own annual nuclear operational targets. As demonstrated in the next table, looking at targets for 2016 contained in the current application, OPG performs worse than its targets. The Board can expect, based on OPG's own track record, that the worsening performance that it itself has forecast will end up being even worse still in practice.

[330] See F2-1-1, p.15 which are based on 2016-2018 Business Plan (A2-2-1, Attachment 1), as compared to updated 2017-2019 Business Plan (N1-1-1, Attachment 1, p.24)

Annual Nuclear Operations Targets versus Actuals

	2013T	2013A	2013V	2014T	2014A	2014V	2015T	2015A	2015V	2016T	2016A	2016V
Pickering												
NPI (Index)	66	67.50	*1.50*	72	64.40	*-7.60*	74.2	68.50	*-5.70*	72.3	76.30	*4.00*
FLR (%)	8.09	9.78	*1.69*	7.76	10.88	*3.12*	5.5	2.83	*-2.67*	5	4.92	*-0.08*
UCF (%)	79.2	73.71	*-5.49*	79.9	75.28	*-4.62*	82.1	79.35	*-2.75*	77.6	74.71	*-2.89*
Total Generating Cost per MWH ($)	65.99	69.62	*3.63*	66.08	68.78	*2.70*	60.25	63.91	*3.66*	71.79	71.82	*0.03*
Non-Fuel Operating Cost per MWH ($)	55.83	58.53	*2.70*	55.71	57.18	*1.47*	53.34	53.95	*0.61*	66.1	60.45	*-5.65*
Fuel Cost per MWH ($)	6.04	5.81	*-0.23*	6.02	5.65	*-0.37*	5.93	5.68	*-0.25*	6.78	5.93	*-0.85*
Capital Cost per MW DER ($)	28.05	33.53	*5.48*	29.98	38.62	*8.64*	6.98	29.42	*22.44*	39.7	35.10	*-4.60*
Darlington												
NPI (Index)	97.7	90.80	*-6.90*	97.9	92.10	*-5.80*	96.1	83.70	*-12.40*	87.3	87.70	*0.40*
FLR (%)	1.5	5.25	*3.75*	1.25	1.53	*0.28*	1	5.10	*4.10*	1	3.17	*2.17*
UCF (%)	88.8	82.92	*-5.88*	93.5	92.09	*-1.41*	86.3	76.86	*-9.44*	91.1	83.98	*-7.12*
Total Generating Cost per MWH ($)	40.25	42.41	*2.16*	36.21	39.63	*3.42*	42.78	52.31	*9.53*	48.09	46.11	*-1.98*
Non-Fuel Operating Cost per MWH ($)	31.76	33.61	*1.85*	27.21	28.33	*1.12*	32.82	38.59	*5.77*	33.84	33.01	*-0.83*
Fuel Cost per MWH ($)	5.39	5.21	*-0.18*	5.35	5.05	*-0.30*	5.25	5.31	*0.06*	5.41	5.60	*0.19*
Capital Cost per MW DER ($)	23.76	24.88	*1.12*	29.48	49.86	*20.38*	34.82	55.82	*21.00*	65.54	54.72	*-10.82*
Legend				***Source:***								
T - Target				*2013-2015 Targets (EB-2013-0321, F2-1-1, p.15, K14.1, p.50)*								
A- Actuals				*2016 Targets (F2-1-1, p.15)*								
V- Variance (Red indicates actuals worse than targets)				*2013-2016 Actuals (J14.4)*								

7.2.12 Ratepayers expect continuous improvement from OPG in the operation of its nuclear facilities. Its own metrics show that it has gotten worse compared to its peers, and will continue to do so.

7.2.13 Unlike Pickering which has always been in the bottom quartile, Darlington has historically been a top performer. That has now changed. In TGC/MWh metric, Darlington was in the first quartile from 2012 to 2014[331]; it has now moved to the median in 2015[332], and OPG admitted it will be in the third-quartile for the entire test period.[333] Based on its own history of performance targets, Darlington may end up being worse than third quartile.

7.2.14 ***Normalization.*** The annual targets in the Application for the test period have been normalized for the impact of the DRP. OPG decided that, for operational targets and benchmarking purposes, it should remove the impact of the loss of generation, and additional costs, when units will go out of service for the DRP.[334] The methodology OPG used to normalize its TGC/MWh metric was to "normalize up" the costs (numerator) and production (denominator) by essentially adding in what they would be if all 4 units were operating.[335]

7.2.15 It appears that after parties asked interrogatories regarding the normalization

[331] Tr.14:24
[332] See 6.2-SEC-63, Attachment 2, p.5
[333] Tr.14:24
[334] F2-1-1, p.16
[335] 6.2-Staff-101, Attachment 1, p.9-11; OPG also proposed to normalize its Non-Fuel Operating Costs Per MWh metric on a similar basis.

methodology, OPG asked ScottMadden to undertake a review.[336] The review was completed in February 2017, and filed right before the hearing. ScottMadden's conclusion was that, while the methodology was "unique but reasonable", a different methodology would have been preferable:

> *"ScottMadden's evaluation found that, while Refurb is a unique mega-project, a more strongly supported and conventional approach to normalization of cost metrics under comparable scenarios was to adjust the distribution of actual costs to reflect performance of the operating units while using actual MWhs generated in the denominator."*[337]

7.2.16 SEC agrees with ScottMadden. Any normalization methodology should be one that "normalizes down" costs to reflect actual production. This is especially important for a generator like OPG which struggles to meet its production forecasts. The Board should require OPG to normalize based on the ScottMadden preferred methodology, and to restate its targets at this time based on that methodology.[338]

7.2.17 The Board should ensure that OPG maintains, and also benchmarks, targets on a non-normalized basis. Ratepayers bear the costs in lost production from the DRP with little to no decrease in costs. Under the RRFE, the Board is interested in measuring outcomes. A non-normalized cost per MWh is what customers will end up paying. They do not pay the normalized cost.

7.2.18 *Staffing Benchmarking.* OPG had Goodnight Consulting ("Goodnight") conduct a staffing benchmarking analysis, similar to the one filed in the last payment amounts proceeding at the direction of the Board.[339] The results show that as of 2014, OPG was 4.1% or 213 positions above the benchmark.[340] Based on OPG's current staffing levels, it believes that it has eliminated the gap and now is at benchmark.[341] There has been no verification of that from Goodnight.[342]

7.2.19 It is far from certain whether OPG has actually closed the gap, or whether the study itself accurately reflects the appropriate level of total staffing. This is for three major reasons:

(a) ***Too Many Exclusions.*** The Goodnight report stated that it excluded 2,036 FTEs that cannot be benchmarked to industry peers.[343] When added to the

[336] See 6.2-Staff-101; Tr.13:41; J13.2
[337] 6.2-Staff-101, Attachment 7
[338] This should be done in the payment order process to ensure the correct targets on the record.
[339] F2-2-1, Attachment 2; F2-1-1, p.11-12
[340] F2-2-1, Attachment 2, p.3
[341] 6.2-SEP-3; F2-1-1, p.12
[342] 6.2-SEP-3(a)
[343] F2-1-1, Attachment 2, p.14

other positions, such as indirect corporate staff, non-regular staff that was not benchmarked and security staff, a total of 3,346 FTEs were not benchmarked.[344] This represents a total of 38.2% of FTEs that were allocated to the nuclear facilities in 2014.[345] This is a significant difference, and thus the results may not be reflective of the actual ideal benchmark. SEC recognizes that the task is hard, and so this not meant to a criticism of Goodnight. However, it should give the Board pause when considering whether OPG has stopped overstaffing its nuclear facilities.

(b) ***2016 versus 2014.*** When OPG says it has closed the gap, it means that as of 2016 when it makes similar exclusions and adjustments, it had reduced the 213 positions that Goodnight found to be above the benchmark.[346] There a few problems with this approach. First, OPG assumes that the benchmark would have remained the same in 2016 as 2014. There is no way to know that. The comparators may have also reduced staff. Second, one of the major exclusions was the DRP program.[347] There are significantly more FTEs in 2016 than 2014 working on DRP, and many of those were transferred from other parts of the organization.[348] Yet, they have not actually left the company and are still in the revenue requirement, just in another non-benchmarked area.

(c) ***Staffing is Increasing In the Test Period.*** Even if OPG was at benchmark in 2016, it is likely not in the test year. Nuclear operations FTEs are increasing in 2017 from 2016 actuals.[349] In fact, they do not return to 2016 levels until 2020.[350] This is occurring even with one Darlington unit offline throughout the test year due the refurbishment.

[redacted]

7.3 Nuclear Fuel Costs (Issue 6.3)

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344 J13.4
345 3346 FTEs (JT13.4) divided by 8767.5 FTEs (2014 FTE Actuals, F4-3-1, Attachment 1, plus Purchased Services Contractors FTEs F4-3-1, Attachment 1. See K12.4, p.46)
346 6.2-SEP-3(b)
347 F2-1-1, Attachment 2, p.14
348 Tr.13:80
349 J13.3
350 *Ibid*
351 [redacted]

7.3.1 This issue was partially settled. SEC has no additional submissions.

7.4 ***Pickering Extended Operations (Issue 6.5)***

7.4.1 ***Overview.*** OPG is proposing to extend Pickering's operations from what was originally supposed to be a 2020 shutdown, to 2022 for 2 units, and 2024 for the remaining 4 units (the plan is known as "Pickering Extended Operations").

7.4.2 To allow Pickering to operate until 2022/24, OPG is proposing to spend $307M from 2016-2020, including $292M during the test period incremental to the regular costs of operating the station.[352] In addition, OPG will need to spend $250M to restore Pickering to normal operations, and if Pickering is extended there will be costs of $1,395M in 2021 OM&A costs.[353]

7.4.3 SEC submits the Board should not allow recovery of costs to enable Pickering Extended Operations. The evidence in this proceeding demonstrates that there is no need for extending Pickering beyond 2020. Ratepayers will be worse off if Pickering is extended beyond its current CNSC-approved scheduled shutdown of 2020. At the very least the Board should require OPG to re-run the economic analysis models to demonstrate that a system benefit still arises from spending the additional ratepayer money.

7.4.4 SEC does realize that not approving Pickering Extended Operations will likely lead to an increase in payment amounts, as opposed to a decrease. This is because while OPG will not have to expend funds on extending the life of the facility, and operating it to 2022/24, it will have to pay severance to employees sooner than it would have to otherwise, and will also have a shorter time to amortize nuclear liabilities.

7.4.5 For ratepayers, while the payment amounts may increase, the share of the total bill that OPG will make up will be smaller and will be less than otherwise would be hve been the case if Pickering is extended to 2022/24.[354] Ratepayers will be better off.

7.4.6 ***Board's Role.*** There are no legislative or regulatory constraints on the Board's role in determining the appropriateness of including, in payment amounts, the costs for extending Pickering. As is the case for all other investments, in making its determination whether costs are reasonable, the Board must determine if there is a need for the underlying asset or activity that warrants the expenditure. Unlike the

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[352] *Ibid*, p.6
[353] 6.5-Staff-116
[354] SEC notes that due to the recently announced Fair Hydro Plan for many customers (although not schools) there may be no difference in total bills during this period. With that said, while for a minority of customers the total bill may not change in comparison to a no Pickering to 2022/24 scenario due to the Fair Hydro Plan, the amount of Global Adjustment that will be deferred will be less. In the long-run all ratepayers will be better off in the no Pickering to 2022/24 scenario.

DRP, in which O.Reg 53/05 specifically requires the Board to assume need[355], there is no similar requirement for the Board to assume the need to extend Pickering until 2022/2024.

7.4.7 OEB Staff's position appears to be that only the system planner can consider need for Pickering.356 This is not correct, for two obvious reasons.

- ***(a)*** First, if only the system planner gets to determine 'need', then there would be no reason for the recent amendments to Reg 53/05, which stipulated the need for the DRP.

- ***(b)*** Second, this would overturn long-standing Board policy in which need is a critical element in the approval process for project expenditures.

7.4.8 SEC recognizes that the Board is not the system planner. That is the role of the Minister of Energy through issuance of the Long Term Energy Plan.[357] However, that does not mean that the Board is required to accept that Pickering must be extended, and that the Board's only role is to ensure that it approves the reasonable costs to do so. That would appear to be contrary to the Government's own expectations regarding Pickering Extended Operations. In their appearance before the Standing Committee on Estimates of the Ontario Legislative in the fall of 2016, the Minister (Hon. Glenn Thibeault) and the Deputy Minister of Energy (Mr. Serge Imbrogno) were clear that no final approval had been given and the next step was to go before the Board:

> *"Mr. Peter Tabuns: ….*
> *Why did you not compare the Pickering life extension to the option of expanding our investment in conservation?*
>
> *Hon. Glenn Thibeault: The deputy was the one who was explaining that piece, so I'll hand that back to the deputy.*
>
> *Mr. Serge Imbrogno: Just a couple of points, Mr. Tabuns. The Pickering life extension: The government has given OPG the green light to pursue the approvals through the regulator, both the OEB and the CNSC, and then to return to the government after we have all the information. I just want to clarify that. They still have to process with the OEB and the CNSC." [emphasis added]* [358]

7.4.9 The Government said that what approval it has given is that OPG is to proceed with

[355] O.Reg 53/05, section 12(v)
[356] OEB Staff Submission, p.97
[357] *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A, section 25.29
[358] Legislative Assembly of Ontario, Official Report of Debates (Hansard), Standing Committee on Estimates (October 26, 2016), p.1510 (K13.2, p.52-53)

seeking the necessary approvals, and then to return to cabinet for a decision:

> *"Mr. Peter Tabuns: Just to be clear, you have not yet made a final decision to extend to 2024. Is that correct?*
>
> *Mr. Serge Imbrogno: That's correct. We've given OPG the authority to go forward, to go through the OEB, and also to the CNSC for regulatory approvals, and then to return, closer to 2017, I believe, for a final decision [emphasis added]*
>
> *Mr. Peter Tabuns: That will be a decision made at the cabinet level?*
>
> *Mr. Serge Imbrogno: It will be made by the minister and, I would suggest, at the cabinet level as well."[emphasis added]* [359]

7.4.10 Regardless of what statements have been made by the Government in the legislature, by press releases, or through any public statements[360], those have no bearing on the legal task the Board is required to undertake in its role in setting payment amounts under section 78.1 of the *Ontario Energy Board Act.* SEC accepts that the Government is in favor of Pickering Extended Operations. On the other hand, the Government, in its role as sole shareholder, system planner, or both, cannot determine the need for Pickering for the purposes of setting payment amounts without promulgating binding regulations or statutory amendments to that effect.

7.4.11 The practical effect of not approving the costs needed in advance for Pickering Extended Operations is that it will not have the funding to undertake it. But what to do in that case is a different decision than the one the system planner makes. The Board is not being asked to say that Pickering cannot be extended, just that ratepayers should not pay for it as it is uneconomic. That jurisdiction is placed squarely on the Board in the OEB Act.

7.4.12 ***Analysis Shows Extending Pickering Not Economic.*** OPG's rationale for Pickering Extended Operations is primarily based on its own economic analysis[361] and an independent analysis undertaken by the IESO[362]. The IESO analysis, most recently updated in October 2015, shows that the system benefit to Ontario of extending Pickering will be between \$300M to \$500M. [363] OPG's own internal assessment reached potential benefits of \$500M to \$600M.[364]

[359] *Ibid*, p.1510 (13.2, p.54)
[360] See for example. 6.5-Staff-115, Attachment 1, 3.1-VECC-09, and any other statements or documents referenced in OPG's Argument-in-Chief, p.89-90
[361] F2-2-3, Attachment 2
[362] F2-2-3, Attachment 1
[363] F2-2-3, p.2
[364] *Ibid*

7.4.13 At a high level, what these two economic analyses are attempting to demonstrate is that extending Pickering to 2022/24, including its additional cost will, on a net present value ("NPV") basis, result in lower system costs (and total bills for customers), since the cost of replacement generation and other required investments will be higher.[365]

7.4.14 The primary problem with both the IESO and the OPG analyses, is that they are outdated. Both were conducted in the fall of 2015. The evidence in this proceeding shows that the underlying assumptions are no longer valid. In fact, a simple update or scrutiny of the assumptions points in one consistent direction: if the model were re-run, the analysis would show that there is no benefit to the system and ratepayers for extending Pickering to 2022/2024. For example:

(a) ***System Demand.*** The IESO did not include any sensitivity analysis to changes in system demand (energy demand in TWh). This is concerning since system demand (i.e. the load forecast) is one of the key components in determining if a generation source is required. The demand that was forecast in the analysis shows that the load in 2020 is 147 TWh.[366] In late 2016, the IESO released the Ontario Planning Outlook ("OPO") to help inform deliberations for this year's Long-Term Energy Plan.[367] The OPO provided 4 different annual system demand sceneries. Two of them (scenarios C and D). Mr. Pietrewicz commented were the "higher outlooks" required for "a very, very aggressive electrification of the Ontario economy".[368] It is unlikely that this aggressive electrification will occur within the time frame forecast in scenarios C and D.[369] Scenarios A and B both provide a system demand forecast that is significantly below that assumed in both the OPG and IESO analysis.

IESO's view of the most accurate forecast has to be the December 2016 Reserve Margin report.[370] In that report, it forecast declining demand from 137.4 TWh beginning in 2017 to 133.6 TWh in 2021.[371] At best, the demand will likely level out past 2021 through 2024.

[365] The IESO analysis found that the benefits i) defers timing of need and the supply/transmission investments that would otherwise be required, ii)defers procurement decisions with respect to new resources, providing more time in exercising options while reducing risk of over investment during a period of supply/demand uncertainty, iii) Provides insurance supply in some years in case of nuclear refurbishment delays, iv) Defers Pickering decommissioning and severance costs, v) Offsets production from natural gas-fired resources, vi) Increases export revenues and reduces carbon emissions. (See F2-2-3, Attachment 1, p.9)
[366] 6.5-Staff-125
[367] Tr.8:85-86
[368] Tr.8:87; Tr.12:56
[369] Tr.12:56-59
[370] Independent Electricity System Operator, *Ontario Reserve Margin Requirements 2017-2021*, December 30 2016, p.11 (K. 13.3)
[371] *Ibid*, p.11

All of this shows that OPG's and the IESO's forecasts in 2015 - that were the assumptions used in their economic analysis - embed a greater system demand than is now likely. The higher demand forecast in the analysis has the effect of overstating the actual benefits. It is likely that with updated demand numbers, Pickering Extended Operations will lead to disbenefits.

System Demand Forecast (TWh)					
Year	OPG 2015	IESO 2015	IESO OPO Scenerio A	IESO OPO Scenerio B	IESO Reserve Margin
2017	143	146	142	143	137.4
2018	144	147	141	143	135.7
2019	146	147	139	132	134
2020	147	148	138	142	133.4
2021	138	150	136	142	133.6
2022	149	151	135	142	
2023	150	143	134	142	
2024	152	155	133	142	
Source: 6.5-Staff-125; 6.5-GEC-43, K13.3, p.11					

(b) ***Pickering Costs***. The IESO model shows that, all else being equal (and even with the outdated load forecast), Pickering Extended Operations will only result in a system benefit if the proposed costs stay within 15% of the forecast.[372] OPG has a terrible record completing major projects on budget.

(c) ***OPG Production.*** The IESO analysis included scenarios where Pickering produces 62 TWh and 65 TWh of production during its proposed extended period of operations.[373] OPG's current application forecasts less than what was provided to the IESO in its 2015 analysis.[374] The IESO's evidence was that the break-even point for economic benefit is 56 TWh.[375] The concern is that OPG has a very poor history of meeting its production forecasts. It has not met its Pickering production forecast in at least the past 7 years.[376] The IESO witness, Mr. Pietrewicz, admitted that he would have had access to similar information up until the end of 2014.[377] He conceded that the variances over a number of years could add up and that as for conductiing a sensitivity analysis

[372] F2-2-3, Attachment 1, p.16
[373] F2-2-3, Attachment 1, p.4
[374] See J12.6, Attachment 1. It shows an IESO PEO OPG production forecast over the 2016-2021 of 117.8 TWh where the application includes a forecast (and is seeking relevant approvals) of 116.9 TWh. With respect to 2021, in which under the no PEO scenario would have zero Pickering production and approval for which is being sought in this application, IESO analysis of Pickering is 18.96 TWh, whereas OPG's forecast is only 18.8 TWh.
[375] Tr.12:104; 6.5-Staff-128(b)
[376] See E2-2-1-2, Table 1, and EB-2013-0321, E2-1-2, Table (K12.2). OPG has missed its production forecast for Pickering each year between 2010 and 2016.
[377] Tr.12:107

for production, "it's a fair thing to look at".[378] It is very unlikely OPG will be able to get Pickering to produce an incremental 62 TWh as assumed.

(d) ***Natural Gas Prices.*** The lower natural gas prices go, the lower the system benefits of extending Pickering to 2022/24.[379] The most important factor in the IESO's analysis is the cost of energy to replace Pickering production. The cost of that energy is significantly influenced by the forecast cost of natural gas since the IESO's replacement generation was forecast in the analysis to come from natural gas generators.[380] OPG confirmed in Undertaking J.8 that gas prices used in the IESO's analysis are double the cost of current gas price futures.[381] Based on March 13, 2017 futures prices, the[382] average natural gas price between 2017 and 2024 is \$3.07/MMBtu. The IESO forecast for the same period is \$6.07 MMBtu.[383]

Even when the additional costs for Cap & Trade are included, which were not in the 2015 analysis, prices are still expected to be significantly below those forecast in the 2015 analysis.[384] Based on the evidence, the IESO analysis is that on average between 2020 and 2024 an additional \$1.15/MMBtu will be applied for Cap and Trade costs.[385] This means the forecast costs, with carbon compliance costs priced in, are approximately \$4.22/MMBtu, still much lower than the forecast of \$6.07 MMBtu in the IESO analysis.

The IESO did conduct its own sensitivity to changes in gas price assumptions. The analysis shows that if one assumes gas prices will be more similar to those seen more recently (2010-2015), as compared to the longer-term historical basis for its forecast, <u>there is a 70% chance that Pickering Extended Operations results in an economic disbenefit to ratepayers.</u>

(e) ***Capacity Costs.*** In addition to replacement energy, the IESO analysis also takes into the account the cost of replacement capacity. The IESO analysis is based on the cost of a new single cycle natural gas plant at a cost of \$130/KW year.[386] The IESO evidence is that if Pickering is going to shut down early, no one will not actually be constructing new single cycle natural gas plants. The IESO admits it is looking at other options:

[378] Tr.12:108
[379] Tr.13:182
[380] F2-2-3, Attachment, p.17
[381] J8.5
[382] *Ibid*
[383] *Ibid*, see IESO forecast converted to nominal US dollars.
[384] See 6.5-ED-29, p.5. Conversion of carbon costs to \$/MMBtu see F-2-2-3, Attachment, p.64.
[385] Based on the IESO Ontario Planning Outlook, it assumed an average price of \$21.35/tonne of CO2 (6.5-ED-29(k)). The IESO analysis assumed 54 kg of Co2/MMBtu F2-2-3, Attachment 1, p,64). \$0.02135kg x 54 = \$1.153/MMBtu
[386] Tr.12:12

> *"Options for addressing resource requirements in the event that Pickering does not operate to 2024 include taking greater advantage of supply resources whose existing contracts expire in coming years, taking advantage of resource options via capacity auctions, and greater use of non-firm intertie transactions."*[387]

SEC submits it is very likely the costs would be considerably less than the amount assumed in the IESO analysis.

7.4.15 The IESO was honest about the risks embedded in the cost/benefit analysis it undertook. What it recommended was not that the Pickering Extended Operations should be done, but that it should "be explored further". [388] As Pietrewicz commented[389]:

> *"MR. PIETREWICZ ...*
> *We recognize in the analysis itself that this could be economically advantageous or could introduce additional costs, depending on many things. And we don't know what that will hold in the future, what the future of gas will be, what the total requirement -- we don't know."*

7.4.16 That is why the Board should, at the very least, require OPG to request from the IESO an update of the economic analysis using new updated forecasts. OPG has the burden in this proceeding to justify the expenditures required for Pickering Extended Operations based on the net benefit to ratepayers. The evidence in this proceeding shows that if the assumptions were updated, there would be no benefits to customers. Based on that information, OPG has not met its burden.[390] The Board can either look at the evidence and draw the conclusion that PEO will not be reasonable, or it can tell OPG to re-run their model, or the IESO's, to include the most up to date information. The results of that analysis could be brought before the Board at a mid-term review.

7.4.17 This Application does not represent a "go/no-go" point in time for OPG. It is not too late for the Board to tell OPG that it will require an update to the economic analysis if it will approve the extension of Pickering to 2022/24. OPG was specifically asked if we have reached the point of no return and if there is evidence that it's just too late not to proceed.[391] Mr. Blazanin responded that it was not their evidence that this was the case. It is not too late to decide not to extend Pickering.[392]

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[387] 6.5-GEC-56(b)
[388] Tr.12:111-112
[389] Tr.12:111
[390] Section 78.1(6) of the *Ontario Energy Board Act*, says that the " the burden of proof is on the applicant in an application made under this section"
[391] Tr.14:151-152
[392] Tr.14:152

7.4.18 This makes sense, since OPG does not even have the requisite approvals for Pickering Extended Operations from its Board of Directors. Mr. Blazanin testified that OPG still has to go to its Board of Directors for approval for the $307M needed to extend Pickering.[393] An updated business case will need to be provided, based on a finalized scope of work.[394] OPG expects that it will update the business case for Pickering Extended Operations "at the end of this year or early next year".[395]

7.4.19 ***New Rationale Not Credible.*** Recognizing that the 2015 assumptions used look very outdated at this point, both the IESO's Mr. Pietrewicz and OPG appear to have shifted to a new rationale for supporting Pickering Extended Operations.[396] Both commented that there were benefits outside of the economic benefits which were the basis of OPG's business case.[397] The added generation from Pickering is important, they now say, considering the changes that are going on in the sector including the DRP and the Bruce Power refurbishments.[398]

7.4.20 SEC finds this new rationale unconvincing as a reason to go forward with an uneconomic project. One would assume that if there was some risk to generation capacity due to the various other projects going on at the same time, OPG would have mentioned it before testifying in the hearing. It would be the central component of the case for the project if true, and yet it does not appear in the IESO analysis or OPG's business case.

7.4.21 Further, there is also no mention of any such risk in the IESO 2017-2021 reserve margin requirements, which determines the amount of capacity that is required to be available above forecast demand.[399]

7.4.22 OPG was asked at the oral hearing at what point internally do the disbenefits make the project no longer viable. OPG responded by stating that it "can't put a number on it" and then attempted to provide a whole set of other reasons that would "affect the decision-making process by the Minister":

> *"MS. GIRVAN: Okay. So internally from your perspective at what point would it not make sense -- and I guess the way I would look at it is if you said, you know, we have got these extra benefits with respect to the refurbishment and -- et cetera and other sort of extra benefits that haven't been included in the economic analysis, how far would the disbenefits*

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[393] Tr.13:179
[394] *Ibid*
[395] Tr.13:181
[396] Tr.8, p.86-92
[397] F2-2-3, Attachment 2
[398] Tr.8:91-92
[399] IESO, *Ontario Reserve Margin Requirements: 2017 - 2021* (December 30, 2016) (See K13.3)

> *have to go before you'd say, look, this -- we really shouldn't be doing this? Is it 50 million, 100 million, 200 million?*
>
> *MR. BLAZANIN: I can't put a number on it because, again, the disbenefit can swing over a period of time. You're talking about a significant asset that provides between 10 and 14 percent of the base load generation, employs a significant number of employees, significantly contributes to the economy in the province. There's a lot of issues and factors that go into the decision-making process, so I couldn't put a value on whether minus 100 was the point or otherwise or if there's something else that would affect the decision-making process by the Minister."*[400]

7.4.23 Those may be reasons why the Minister (whether as system planner or as representative of the shareholder) may want to have the project go ahead regardless of the economics, but that is not a rationale for OPG as a regulated entity to pursue it, nor a rationale for the Board to approve it if there are net disbenefits to ratepayers. The evidence shows that re-running the model would almost certainly produce significant evidence of disbenefits of the project and that the rationale for the project is shifting.

7.5 ***<u>Compensation (Issue 6.6)</u>***

7.5.1 ***Overview.*** OPG's employee compensation costs have been a constant and reoccurring issue in each of its payment amounts proceedings. It is one of the largest single categories of OPG's costs, representing almost 50% of its nuclear revenue requirement.[401] OPG is seeking approval of $7,995M for nuclear compensation costs over the test period.[402]

7.5.2 Not only is this the largest single cost category, but it is also the one which OPG has the hardest time getting under control. The benchmarking results show that, while OPG's compensation levels may be slightly improving compared to those the Board has seen in other proceedings, those results are a far cry from levels that can fairly be called reasonable.

7.5.3 Moreover, those results themselves only tell part of the story. OPG's pension and benefits are also significantly above the benchmark, and progress on that front is moving even slower.

7.5.4 Simply put, OPG's compensation costs are excessive, and it is no longer appropriate for ratepayers to bear the cost of OPG's inability to get its compensation costs in line.

7.5.5 OPG may be legally required to pay certain compensation costs to employees, as set

[400] Tr.15:90-91
[401] Argument-in-Chief, p.94
[402] F4-3-1, p.6

out in collective agreements with its unions and employment contracts with management, but that does not mean those costs should be passed on to ratepayers. To pass on unreasonable costs, even if OPG will have to pay some of them regardless, would not allow the Board to exercise its role as market proxy. The Board has made these very findings in each of the last two proceedings with respect to compensation,[403] one of which was fought vigorously by OPG and its unions, but ultimately upheld by the Supreme Court of Canada.[404]

7.5.6 SEC therefore submits it is no longer reasonable for the Board to simply 'adjust' OPG's compensation At this point, the fair result is to determine the reasonable compensation costs, and allow only that number as part of the revenue requirement. Anything greater should be disallowed.

7.5.7 ***Compensation Benchmarking.*** OPG retained Willis Towers Watson ("WTW") to prepare a compensation benchmarking study as required by the Board's previous payment amounts decision. The study segmented OPG by specific positions to compare them to the most relevant set of peers (nuclear authorized, utility, and general industry). The results of the study show that compensation to the PWU and Society employees, who represent 90% of OPG's employees[405], is significantly higher than benchmark, whereas management is below benchmark.[406]

WTW Benchmarking Results			
OPG Group	# OPG Matched Incumbents	% +/- Target Market Base Salary	% +/- Target Market TDC
PWU	4475	13%	8%
Society	2151	18%	8%
Management	784	-7%	-13%
Source: F4-3-1-Attachment, p.11			

7.5.8 The methodology WTW used in determining the base salary was to use OPG employee salaries as they were on April 1st, 2015.[407] For total direct compensation, it included an assumed bonus or incentive payment for each employee who was eligible to receive one, called the Stakeholder Return Program ("SRP"), equal to the 'target' score (a score of 4 out of 7).[408]

7.5.9 There are a number of concerns and issues with this methodology in the report:

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[403] *Decision with Reasons* (EB-2013-0321 - OPG 2014-2015), November 20th 2014; Decision with Reasons (EB-2010-0008 OPG 2011-2012), March 10, 2011, p.84-88
[404] *Ontario (Energy Board) v. Ontario Power Generation Inc*., 2015 SCC 44
[405] F4-3-1, p.3
[406] F4-3-1, Attachment, p.2
[407] Tr.17:10-11
[408] Tr.17:-11

(a) ***Share Grant Compensation Not Included.*** The salaries used for the benchmarking study are now two years old. They do not reflect some of the major compensation components which were part of OPG's current collective agreements with the PWU and Society. Starting in 2017 and 2018 respectively, the PWU and the Society employees will earn in addition to their regular compensation, 2.75% of the value of their 2015 base compensation paid in Hydro One shares.[409] None of that is included in the benchmarking[410]. They will continue to get 2.75% of their 2015 base salary every year for the next 15 years.[411]

(b) ***Lump Sum Compensation Not Included.*** The PWU and Society will also receive a cash lump sum payment, equal to 1% of their base salary, in the first year of their respective collective agreements, and 2% in the second year.[412] This means the PWU employees will have received, in addition to their base salary, 2% in 2015, and 1% in 2016. Society employees will have received a cash lump sum of 2% of their base salary in 2016, and another 1% this year in 2017. Even though amounts for the lump sum will be paid in 2015 for PWU members, that was not included in the WTW benchmarking analysis.[413]

(c) ***Incentive Compensation Higher Than Forecast***. Using the target score of 4 of 7 of the SRP for determining the incentive/bonus component of total direct compensation assumes that on average, employees will get the median score of 4. The problem is that they, in fact, receive a score higher than 4 on average. Since the introduction of the SRP in 2014 which replaced the previous incentive system that was highly criticized by the Auditor General, on average, OPG employees received scores higher than 4.[414]

(d) ***Nuclear Authorized Employees Benchmarked At 75th Percentile***. While WTW benchmarked most of OPG's employees to the 50th percentile, it benchmarked nuclear authorized positions at the 75th percentile.[415] It did so as requested by OPG.[416] OPG's position is that this is appropriate due to the work of authorized nuclear operators being more complex at OPG than the comparators[417] since they are primarily working at one and two unit reactors. SEC notes that in the past, the Board has told OPG that it does not believe that

[409] F4-3-1, p.17; Tr.17:3-4
[410] Essentially, the value of this compensation in kind was treated as zero. This is incorrect. Paying in cash, or gold, or shares, or anything else, is still a cost, and in the end the ratepayers will still bear that cost.
[411] Ibid
[412] F4-3-1, p.17; Tr.17:3
[413] Tr:17:18
[414] See 6.6-SEC-72, Attachment 2, p.2 for actual 2015 SRP scores. See Undertaking 17.2 for actual 2016 SRP scores
[415] Tr.17:35
[416] Tr.15:85; Tr.16:54-55
[417] Tr:15:55-59

setting a compensation benchmarking at 75th percentile is appropriate.[418] But regardless of the previous direction, more units do not necessarily make the work more complex for an individual employee. The station with more units requires more employees to operate at any given time; it does not mean each one of those individuals' jobs is harder or more complex. At some level no two positions in different companies are the same. They each have unique features. But that goes both ways. There are likely other jobs that OPG employees do that are easier at the comparator organization. OPG did not consider this in setting the benchmark for other positions.[419]

(e) ***No Adjustment for Less Than 40 Hours Worked.*** The WTW benchmarking methodology is not consistent with a key component of the Goodnight staffing benchmarking study. Goodnight made adjustments to the number of benchmark FTEs required on the basis that the comparators worked primarily 40-hour work weeks, and many OPG nuclear employees worked 35 hours a week.[420] Goodnight added employees to its benchmark to adjust for the difference in work weeks, as 33% of employees in nuclear operations work less than 40 hours a week.[421] Since OPG employees work less, OPG will need more employees. The WTW analysis makes no adjustment for hours of work. If Goodnight believes it is appropriate for more employees to be required since OPG employees work less, then to be consistent, WTW should take into account hours of work in determining benchmark compensation. It did not.[422] If OPG's employees work less than the comparators, they should get paid less. WTW should have made an adjustment for hours of work.

(f) ***Significant Number of Positions Not Benchmarked***. WTW does not benchmark a significant number of OPG positions. There are still 22% of OPG employees that were not benchmarked.[423] This includes an undisclosed number of employees who work for OPG nuclear security.[424] SEC understands why

[418] *Decision and Order* (EB-2010-0008 – OPG 2011-2012), March 10, 2011, p.85-86:

> The evidence provided does not substantiate the assertion that the positions selected by OPG are sufficiently different to warrant the use of the 75th percentile. Although OPG stressed that its work requirements (particularly on the nuclear side) are highly technical, the Board observes that many of the comparators in the Towers Perrin study would also require highly technical skills, and some of the comparators also operate nuclear facilities. Indeed the job classifications used in the Towers Perrin report are compared against each other on the basis that they are at least broadly speaking comparable.

[419] Tr.17:10
[420] F2-2-1, Attachment2, p.28; Tr.17:19
[421] J13.13. Nuclear operations does not include any corporate allocated support employees or those employees who work directly for the DRP.
[422] Tr.17:19; In nuclear operations, 96% of Management employees work less than 40 hours of week, 66% of Society employees work less than 40 hours of week, and 6% of PWU employees work less than 40 hours a week. In total 33% work less than 40 hours a week (see J17.13)
[423] F4-3-1, Attachment 2, p.3
[424] Tr.16:63

OPG did not include these security employees, as that would reveal their numbers, which is a security risk. The problem is that a number of them appear to be very highly paid, as they appear on the Ontario Government's Public Sector Salary Disclosure list (the "Sunshine List"). In Undertaking J17.4, OPG states that the average base salary for PWU nuclear safety officers is \$84.7K.[425] The problem is that they have done no benchmarking to determine how that compares to comparators.

(g) ***Other Compensation Elements Not Included.*** There is additional compensation that OPG employees get that is not considered in the benchmarking study. This includes shift premiums, on-call premiums, and overtime.[426] Combined, these amounts make up a very material amount of some employees' compensation.

7.5.10 ***Sunshine List.*** The indicators are that OPG's compensation levels are going in the wrong direction. The number of OPG employees on the Sunshine list, which includes all whose compensation is \$100,000 or greater, is increasing after a period of reduction during the previous test period (2014-2015). In 2014 and 2015, afer the EB-2013-0321 proceeding, there was a reduction in OPG employees on the Sunshine list, but in 2016, the number took a sharp increase.

OPG Public Sector Salary Disclosure				
	2013	2014	2015	2016
# of employees (\$100,000 or greater)	7958	7668	7632	7730
Source: K17.1, p.43 (https://www.ontario.ca/page/public-sector-salary-disclosure)				

7.5.11 More importantly, the number of employees whose compensation is above \$200,000 and even above \$300,000 a year is also increasing, both in absolute numbers and also as a percentage of total T4's OPG issues in a year. After declining in 2014 from 2013, likely due to the 2013 Auditor General's Report which was highly critical of OPG's compensation levels and was a focus of the Board's last decision[427], these "top earner"[428] employees decreased. Then, after the Board's decision in 2014, they are once again starting to increase. In fact, as a percentage of T4's issued (which will be much higher than actual number of OPG employees at any given time in the year), it is higher than it was previously in 2013.[429]

[425] J17.4
[426] 6.6-Staff-142(c); Tr.17:17
[427] K17, p.41-42
[428] Top earners is what the Auditor General called OPG employees who earned over \$200,000 (See K17.1 p.42)
[429] J17.5; J17.7

OPG Public Sector Salary Disclosure ($200,000)	2013	2014	2015	2016
# of employees ($200,000 or greater)	526	369	428	505
% of total T4s	3.90%	2.90%	3.40%	4.00%
# of employees ($300,000 or greater)	48	31	48	59
% of total T4s	0.40%	0.20%	0.40%	0.50%
Source: J17.5, J17.7				

7.5.12 It appears OPG took action after the 2013 Auditor General's Report and the Board's previous payment amounts decision, and then when the spotlight shifted from the company, it returned to its previous habits of paying unreasonable amounts to its employees. Once more it is asking the ratepayers to pay.

7.5.13 SEC submits that the Board should not allow recovery from ratepayers of more than the benchmark 50th percentile of total direct compensation, which is a reasonable level of compensation for OPG's employees. OPG estimated, based on information provided by WTW, that if employees were at what it believed was the benchmark in 2016, it would result in a reduction of OM&A of $29.6M (in 2016).[430] SEC submits OPG's analysis is wrong, as discussed during the hearing. The OPG analysis only includes the reductions to the benchmark for approximately 78% of the employees who were part of the study. It also includes nuclear authorized employees being benchmarked at the 75th percentile.[431]

7.5.14 Based on SEC's detailed analysis included in Exhibit K17.1 and discussed during the hearing, the reduction in 2016 to get all nuclear direct or allocated employees to the benchmark would have been $46.7M.[432] The analysis has been reproduced as Appendix A to these submissions. OPG agreed the math is correct.[433]

7.5.15 Ms. Rees though, did object to the extrapolation calculation being appropriate, on the basis that the unmatched positions may in fact benchmark lower on average than the other positions if they could have been matched.[434] Yet, at the same time, in defending the study not including all of its employees, Ms. Rees did say that "I do think 78[%] is a reflective sample of the organization".[435]

7.5.16 ***Compensation Reductions***. SEC submits, based on the $46.7M reduction that would

[430] JT3.12; 6.6-SEC-83(b)
[431] Tr.17:28-29
[432] See K17.1, p.18-19; Tr.17:278-35. The calculation extrapolates OPG's result for the difference between 50th percentile and actual compensation for each in each group (PWU, Society, and Management) against their segment (Utility, Nuclear Authorized, General Industry), to include all employees in that category not just the ones which WTW could benchmark. It also moves the nuclear authorized comparator to the 50th percentile.
[433] Tr.17:32
[434] Tr.17:31
[435] Tr:17:31

be required in 2016 to be at benchmark cost, at the very least, that annual amount should be applied during each year in the test period. This would result in a reduction of $233.5M over the entire test period. The reason this is the minimum is that as discussed previously, the 2016 WTW benchmarking report does not include many large aspects of OPG's compensation, including lump sum payments, and Hydro One shares that will be paid.

7.5.17 OPG's movement since the last payment amounts proceeding slightly closer to its benchmarks is a positive sign, but it is simply not sufficient. Ratepayers should not have to pay costs that are above benchmark. The Board put it best in Hydro One Distribution's most recent decision (EB-2013-0416), when it commented that "[w]hile the OEB recognizes the progress that Hydro One has made over the last few years in getting closer to the market median, the OEB does not find that it is fair that ratepayers pay for a 10% premium over the market median".[436] It then made significant reductions to Hydro One's proposed compensation costs.[437]

7.5.18 With OPG, SEC submits that the Board must finally say enough is enough. Ratepayers should not bear any of their above-benchmark compensation costs.

7.5.19 ***Bargaining Mandate.*** [redacted]

7[redacted]

[redacted]

[436] *Decision (*EB-2013-0416/EB-2014-0247 - Hydro One Dx) March 12 2015, p.24
[437] *Ibid*
[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

7.5.28 ***2013 Auditor General Issues Remain.*** In addition to high salaries and increasing employees on the Sunshine List, there are a number of areas in the 2013 Auditor General's Report regarding OPG's Human Resources practices that are unresolved in whole or in part. These include:

(a) ***Management Incentive Pay Program.*** OPG's management employees have the SRP incentive compensation scheme.[450] The program was introduced in 2015 to rebrand and replace the Annual Incentive Plan ("AIP").[451] The new program was put in place as a result of the significant shortcomings identified by the 2013 Auditor General's report. The Auditor General had a number of criticisms of the AIP, including "performance scores were skewed towards executive and senior management", and "a stronger link between the award and staff performance based on documented annual evaluations" was required.[452] While OPG has rebranded the program, both criticisms are still valid today for a few reasons.

First, based on the 2014 through 2016 SRP scores breakdown, executive and senior management are still much more likely to get a score above the target score than employees in lower bands.[453] In fact, the gap between the two categories of management is getting larger, not smaller.

[redacted]

[450] Tr.17:11; F4-3-1, p.11
[451] 6.6-SEC-76
[452] K15.6, p.34
[453] 2016 scores: J17.2, 2014-2015 score: 6.6-SEC-72, Attachment, p.1-2

More troubling, the scores in each of those years skew towards scores above target. It appears that between 2014 and 2016, the effect increases.[454] This is a strong indicator that the goals OPG sets for management employees are too low. If the goals were set appropriately, the scores at the end of the year should be closer to a bell curve shape, where there are an equal amount of employees above and below the "target score".

Second, OPG's response to the second main criticism has not actually been properly implemented. Its response to the Auditor General's criticism about the lack of a strong link between awards and performance, as well as issues of transparency, OPG implemented SMART (specific, measureable, achievable, realistic and time-bound) objectives.[455] OPG's internal audit group found in the fall of 2016 that 43% of performance plans did not even have the minimum three SMART performance objectives.[456] That means only 57% of the plans had met the requirement. This is a risk OPG categorizes as having a high level impact.[457] Even after the audit, OPG does not plan to remedy this problem. Its 2017 target is that 70% of performance plans have the three high quality SMART objectives included.[458] That is an improvement of just 13%, even if it is actually achieved. This is unacceptable, and is a sign that OPG does not take seriously enough the findings of the Auditor General report about properly linking measurable performance to incentive pay.

(b) ***Re-Hire Policy.*** The most troubling aspect of OPG's response to the 2013 Auditor General's report is with respect to its re-hire policy. In the report, the Auditor General strongly criticized OPG's policy of essentially allowing employees to retire, and then immediately go back to work as contract employees.[459]

In its 2015 follow-up report, the Auditor General found that OPG had fully implemented the recommendation, mainly on the basis that OPG had implemented a new re-hire policy, which required former employees to wait a full year before they can be re-hired on a contract basis.[460] Yet, right after the Auditor General's 2015 report which gave OPG a clean bill of health on this issue, OPG lowered the one-year requirement to 6 months, and eliminated it altogether for some positions.[461] OPG confirmed in response to an undertaking

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[454] *Ibid*
[455] K17.1, p.50; Tr.17:66
[456] JT3.4, Attachment 9, p.4; Tr.17:66
[457] *Ibid*
[458] J17.8
[459] K17.1, p.46
[460] K15.6, p.34; 6.6-Staff-140
[461] 6.6-Staff-140, p.2, Chart 1

that it "never told the Auditor General".[462] SEC finds this troubling. OPG implemented this 2013 report recommendation, and then as soon as the follow-up report was completed, changed the policy which it knows would not have been looked at favorably by the Auditor General.

(c) ***Sick Leave.*** The 2013 Auditor General's report criticized OPG's sick leave policy as overly generous and open to significant abuse.[463] The policy before 2001 provided that employees could carry-over sick days from year to year, but also restore their used sick days after 5 years. Over half of OPG's employees are still on this plan.[464] In the 2015 follow-up report, OPG told the Auditor General that it could not make any progress with the PWU during collective bargaining and that it would try with the Society a year later.[465] OPG confirmed during the hearing, it did not make any progress on the issue with the Society during collective bargaining.[466] SEC submits this is unacceptable. Staff under this prior plan had, on average, accumulated 162 sick day leave credits at full pay, and 191 credits at 75% half pay.[467] This is a significant cost to ratepayers.

7.5.29 ***Pensions & Benefits Benchmarking.*** OPG's pension and benefits are more than just generous, they are unreasonable. This has been noted by many reviewing these plans, in addition to the Board, which has made similar comments in the past, not just with respect OPG's pension plan, but also its benefit package to both current and retired employees (i.e. other post-employment benefits or "OPEBs").[468] WTW conducted a benchmarking of OPG's pensions and benefits.[469] The report shows that overall OPG's pension and benefits are valued from the employee's perspective at 32% above the benchmark comparators.[470]

[redacted]

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462 J17.4; Tr.17:55-56
463 Tr.17:64-65; K17.1, p.44;
464 K17.1, p.44;
465 *Ibid*
466 Tr.17:65
467 K17.1, p.44;
468 For example, see for example: 2013 report of the Auditor General of Ontario (17.1, p.42), 2014 Report on the Sustainability of Electricity Sector Pension Plans (K16.2, p.35), Towers Watson CHRC Briefing originally filed in the 2013 application (K16.2, p.106)
469 F4-3-1, Attachment 2, p.27
470 *Ibid*
[redacted]

[redacted]

7.5.31 Unlike with compensation, SEC is unable to calculate the revenue requirement impact of being at benchmark. OPG said it could not provide such a calculation.[474] Because of that SEC is not in a position to provide a specific proposed reduction. The Board is left to guess what the appropriate pension and benefits amounts are for existing and retired employees that should be included in the revenue requirement. This is unacceptable.

7.5.32 ***Pension Contribution Ratio.*** One of the major reasons the value of OPG's pension plan is it so high is that relative to other companies, as well as the Ontario public service, the contribution ratio between employer and employees is badly skewed.[475]

7.5.33 OPG contributes a relatively high amount to the pension plan as compared to its employees. The contribution ratio should be 1:1 which represents an equal share of contributions from the employer OPG and its employees. But OPG's ratio is currently <u>still</u> at least 2:1 in 2017.[476]

7.5.34 Even that calculation is misleading, since it does not include special payments that OPG (and not the employees) is required to make when the plan is underfunded. These amounts have been significant in the past, and are expected to be approximately $54.8M in each of 2017 and 2018.[477]. If special payment amounts are included the ratio moves from 2:1 to 2.7:1 for 2017 and 2018.[478]

[redacted]

[redacted]

[redacted]
475 K15.6, p.30
476 F4-3-1, p.16
477 See 6.6-Staff-156, Attachment 1, p.22. OPG is required to pay in both years in addition to its normal cost, $52.16M in special payments toward amortizing unfunded liabilities and $2.59M towards special payments amortizing solvency deficiency.
478 See K16.2, p.50. The ratio between employer / employee (pension plan payment including special payments) is 73/27 in 2017 and 72/28 in 2017.
[redacted]

[redacted]

7.5.37 ***Benchmarking For Next Proceeding.*** SEC submits that for the next payment amount proceeding the Board should require OPG to conduct one benchmarking study that includes all elements of what employees and the public would consider part of a compensation package, e.g. base salary, incentive pay, lump sum payment, share grant value, and the value of pensions and existing and future benefits.

7.5.38 WTW compensation benchmarking considered only base and incentive pay (total direct compensation). As discussed above, it did not include other aspects of compensation such as the share grants and lump sum payments paid. WTW's pension and benefits benchmarking was an entirely separate exercise, conducted with a different set of comparators and using a different methodology.[482] The benchmarking should all be compared against comparators on the same basis. Ms. Rees recognized that all three major elements (base, incentive, pension and benefits) matter to employees.[483] Comparing these against a single set of comparators provides the most accurate benchmark. OPG's piecemeal method does not provide for an accurate assessment of how OPG compares to its peers.

7.5.39 ***Summary.*** SEC submits the Board should reduce OPG's OM&A related to compensation by at the very least [redacted] would represent OPG being at the 50th percentile in total direct compensation benchmarking of ($46.7M per year) [redacted]

7.5.40 There should be potentially more reductions, although the specifics are hard to quantify. They include, but are not limited to,

- Additional amounts to reflect that the WTW benchmarking study does not include significant amounts of compensation related to the share grants and lump sum payments;
- [redacted]
- [redacted]
- [redacted]

[482] Tr:17:23; F4-3-1, Attachment 2
[483] Tr.17:23

[redacted]

7.6 ***Common Costs (Issue 6.7)***

7.6.1 OPG is seeking approval for $2,374M in common support costs (also known throughout this argument as "common costs") that are allocated to the nuclear business during the test period.[484] The Board should reduce this amount as it does not reflect an appropriate level of spending on common support costs.

7.6.2 In that last payment amounts proceeding, the Board noted that it could not draw the same conclusions that parties did regarding OPG's history of over-forecasting corporate support costs due to business transformation that was on-going at that time.[485] The evidence since that decision now allows for the conclusion to be drawn. OPG has over-forecast its common support costs over the last three years. There is no reason to believe that it will not do so again, especially considering the 2016 forecast, which is based on the same business plan that underlies this application (2016-2018 Business Plan), it under-spent by 3.64%.[486]

Common Support Costs										
	2014 Approved	2014 Actuals	2014 Variance	2015 Approved	2015 Actuals	2015 Variance	2016 Budget	2016 Actuals	2016 Variance	Total 2014-16 Variance
Costs ($M)	433.9	416.2	*-4.08%*	417.4	418.8	*0.34%*	442.3	426.2	*-3.64%*	-2.50%
Source: F3-1-2, Table 2; J13.2, Attachment 1										

7.6.3 In the last payment amounts decision, the Board required OPG to undertake an independent benchmarking study of its common support costs. OPG retained the Hackett Group who not only benchmarked against peer companies on four metrics[487] for each main business area (Information Technology, Human Resources, Finance, and Executive and Corporate Services[488]), but also provided an analysis of OPG's costs before (2010) and after (2014) business transformation on the same metrics.[489] While the analysis shows that OPG has improved against itself since 2010, with the exception of IT Cost per End User, it is still above the benchmark. In some cases, it is

[484] F3-1-1, p.1
[485] *Decision and Order* (EB-2013-0321 – OPG 2014-2015), November 20, 2014, p.95:

> Parties indicated that OPG has historically forecast higher corporate support costs than it actually spent. The Board finds it difficult to draw conclusions from the historical variance analysis as provided in evidence, as the underlying numbers are affected by employee migration to centre-led functions as a result of Business Transformation.

[486] F3-1-2, Table 2; J13.2, Attachment 1
[487] IT cost per End User, HR cost per Employee, Finance Cost as a % of Revenue, and ECS Cost as a % of Revenue
[488] Executive and Corporate Services ("ECS") includes costs for risk management, environment, health and safety, procurement and real estate and facilities management (F3-1-1, p.15)
[489] F3-1-1, Attachment 1

very significantly above benchmark.[490]

7.6.4 Measured in quartiles, OPG's 2014 costs on the Hackett designed metrics are in the top quartile for IT, and in the 3rd quartile for HR and Finance.[491] ECS was not only in the 4th quartile; OPG was the worst utility of the 19 benchmarked.[492]

7.6.5 Considering that OPG's common support costs have only increased since 2014[493], it is not likely OPG has made any progress on moving towards the benchmark since then. OPG is also not proposing any significant efficiency or productivity initiatives to get these costs, especially its ECS costs, to reasonable levels during the test period.

7.6.6 The Board should reduce OPG's corporate support costs so in the areas where it requires improvement, they are more in line with the benchmark.

7.6.7 More importantly, the Board should reduce OPG's forecast costs on the basis that historically it does not spend what it says it requires. The Board should reduce the test period costs by 2.5% a year, which represents the 2014-2016 total variance between actuals and the Board approved/ budgeted amounts. This results in a reduction over the test period of $55.7M.[494]

[490] *Ibid*, p.12-15
[491] 6.7-Staff-169, Attachment 1, p.2-3
[492] *Ibid.*, p.3; Tr.20:28
[493] F3-1-2, Table 2
[494] 2017 ($11.2M), 2018 ($10.9M), 2019 ($11.7M), 2020 ($11.13M), 2021 ($11.35M) = 55.7M

8 NUCLEAR LIABILITIES

8.1 *Recovery Methodology (Issue 8.1)*

8.1.1 ***ONFA vs. GAAP Method?*** The issue presented to the Board in this proceeding is whether the current GAAP (accrual) method of including nuclear liability costs in rates remains appropriate. SEC believes it is no longer the appropriate method. In our submission, the amounts to be recovered in rates should be the amounts OPG will actually expend on present and future nuclear liability costs in the test period, as stipulated by the government through ONFA. That is, what would be called for accounting purposes the cash method, but is actually an accrual method mandated by the Government under ONFA, is the appropriate recovery methodology.

8.1.2 To assess which is the appropriate method, SEC believes the Board should ask and answer the following question: Should the Board require ratepayers to pay amounts for nuclear liability costs today when those monies will never actually be spent on nuclear liability costs, either today or in the future? If the Board asks that question, in our submission the ONFA method is clearly the correct approach to take.

8.1.3 ***What Are You Doing With the Money?*** The following exchange in the oral hearing is instructive on the question of how to recover nuclear liabilities in rates:

> *"MR. SHEPHERD: ... 1.7 billion dollars is coming from the ratepayers. 1.1 billion is your net out-of-pocket because you're going to get some money from the seg fund, right, so you're going to be out-of-pocket \$1.1 billion. You're left with \$600 million.*
> *What are you going to do with that money? Are you going to spend it on nuclear liabilities? Yes or no?*
> *MR. MAUTI: What I think you're doing, Mr. Shepherd, is confusing how it is that we recover nuclear liabilities from trying to equate that to a dollar-for-dollar expenditure for nuclear liabilities, and that's not the way that methodology was originally developed and it's not the way it's supposed to work."*[495]

8.1.4 Following that exchange, there was a back and forth in which we kept trying to get the witnesses to explain what they were going to do with the extra money. That culminated in the following:

> *"MR. MAUTI: I think the money that we have coming in would have to be sort of considered as being the ratepayers paying for the cost of nuclear liabilities on a cost recovery basis, as was originally litigated*

[495] Tr.21:50

and determined as part of that 2007 proceeding.

This was one of the areas that received a lot of attention, and there was a lot of discussion related to how nuclear liabilities should be funded and should be incorporated into rates.

There were proposals that were put forward by Board Staff, by several of the intervenors in this room, and there was a 35-page finding from the Board in terms of what's the most appropriate methodology. That methodology is based fundamentally on accounting principles. The largest components of the recovery methodology are, as we've talked about, depreciation on our asset retirement costs, and it's paying for incremental waste volumes that are generated during production. The cost, the cash, to manage those waste volumes that come forward today will be expended over several decades into the future. So that's why trying to compare a cash expenditure in any particular period with the actual cost of nuclear generation during a particular year is a difficult concept, but is one that you need to understand, liabilities are a hundred-year proposition in terms of trying to manage these things. And you're trying to properly match the cost of generation of nuclear in one year with the actual costs that are incurred from that generation. And that does not equal the cash expenditures made in any particular period. That's the fundamental -- and I know you're asking -- a simple person asked you that question, but I think that's probably the simplest way to try to describe it, but we can go into a lot more detail, I know, but – "[496] [emphasis added]

8.1.5 ***Has The Board Already Decided This?*** What the Applicant's witness failed to note is that the question of whether the GAAP approach to valuing nuclear assets (i.e. the accrual method) should be used, or whether the Government's ONFA methodology (i.e. the cash method for accounting purposes) should be used, never came up in EB-2007-0905. The Board explains as follows:

> *"In addition to OPG's rate base method, four other methods of determining the revenue requirement impact of the nuclear liabilities were discussed during the hearing. Those methods and OPG's rate base method are summarized in Table 5-5, which is based on calculations filed by OPG. The table deals only with the "return on rate base" aspects of each method. It omits depreciation of unamortized ARC and the other elements of the revenue requirement proposed by OPG that were not opposed by any party."[497]*

8.1.6 In short, all parties to that proceeding accepted that nuclear liabilities would be included in rates based on accounting principles. The only issue that was explored

[496] Tr.1:51-52
[497] *Decision with Reasons* (EB-2007-0905 - OPG 2008-09), November 3 2008, p.80 ["*EB-2007-0905 Decision*"]

was whether the rate base component – the ARC – should attract the full cost of capital, or a lesser amount, or none. In the end, the Board agreed with SEC and others that a lesser amount, the weighted average cost of debt, should be used.

8.1.7 At no time was there any discussion of whether the ONFA approach or the GAAP approach would be more appropriate for rate recovery.

8.1.8 What was not considered by the Board is whether the accounting methods governing calculation of nuclear liabilities are appropriate for ratemaking purposes. What was also not considered by the Board is whether the Ontario Nuclear Funds Agreement represents a decision by the Province as to how to calculate OPG's obligations to fund nuclear liabilities[498]. Further, at no time did the Board know that the amounts for nuclear liabilities on the financial statements of OPG were calculated in a manner inconsistent with ONFA.

8.1.9 It is also perhaps useful to note that the Board was considering the question at a time when the seg funds were not, in aggregate, fully funded, and immediately after a substantial increase in the future liabilities at the end of 2006. Further, it is not clear on the record of the EB-2007-0905 proceeding that there would have been a significant difference between GAAP-based rate recovery and ONFA-based rate recovery. At that time, the Board was expecting that contributions to the seg fund alone would be $2.1 billion over the period 2008-2017[499].

8.1.10 OPG has been asked repeatedly whether they have any justification for collecting in rates more for nuclear liabilities than they are actually required to spend, and their only answer is the EB-2007-0905 decision[500].

8.1.11 In fact, in their Argument-in-Chief OPG implies that the conclusions of the Board in the EB-2007-0905 decision, accepting the accrual approach to revenue requirement, were necessary in order to comply with O.Reg.53/05[501]. What actually happened is that the Board reviewed that regulation, and concluded that it was not constrained in how it should determine revenue requirement[502].

8.1.12 SEC submits that the question of whether ONFA or GAAP is the appropriate basis for rate recovery of nuclear liability costs is presented to this Board for the very

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[498] The Board concluded that the Province, in O.Reg. 53/05, had left it open to the Board to determine how revenue requirement for nuclear liabilities would be calculated. The Board did not consider whether the Province, in ONFA, had provided guidance as to all or some aspects of that calculation.
[499] *EB-2007-0905 Decision*, p.66.
[500] Including in their Argument-in-Chief, where through thirteen pages (pp.131-143) OPG goes on at length about how to recover nuclear liabilities in rates, but only ever uses one justification to back it up: EB-2007-0905. The argument appears to be: "We won this one already. We don't need to justify it again."
[501] See, e.g., p.143
[502] Referring specifically to s. 6(1) of the Reg., which so states in explicit terms. (see p.77 of the *EB-2007-0905 Decision*).

first time. In our submission, this Board should make a determination based on the merits, not based on precedents, especially a precedent that did not include a debate on the merits.

8.1.13 ***The Purpose of Rate Recovery.*** OPG's Mr. Mauti got it right in the quote in para. 8.1.4 above, where he says "*The cost, the cash, to manage those waste volumes that come forward today will be expended over several decades into the future*." He then goes on, however, to talk about the accounting concept of matching costs to the periods in which the benefits to ratepayers are received. This is reiterated in the Argument-in-Chief, which says:

> *"An overall objective of the financial accounting treatment of AROs is to reflect the costs in the periods they are incurred, by matching them to the benefits derived from the asset."*[503]

8.1.14 This is undoubtedly true, but that – the matching principle - is not the primary reason for recovering funds in rates to pay for future nuclear liability costs. The OPG website, in its introduction to the discussion of the ONFA funds, says:

> *"OPG is responsible for the management of used nuclear fuel, and low and intermediate level nuclear waste, and eventual decommissioning of all of its nuclear facilities, including the stations on lease to Bruce Power, as required by the CNSC. OPG recognizes that the cost of long-term nuclear waste management, and the cost of decommissioning, must not be passed on to future generations."*[504]*[emphasis added]*

8.1.15 SEC submits that this is what it is all about. The reason to recover funds from ratepayers today is to set those funds aside, ensuring that future generations don't have to pay for our use of nuclear power. This is not an accounting exercise. This is a funding exercise, driven by intergenerational equity and fairness.

8.1.16 ***What is the Question?*** In our submission, the Applicant in this proceeding is asking and answering the wrong question.

8.1.17 The Applicant is asking the question: What do the accounting rules say is the cost that should be matched against current nuclear production?

8.1.18 In our submission, the correct question is: What is the appropriate amount to collect from current customers to either spend or set aside for nuclear liability costs, now and in the future?

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[503] Argument-in-Chief, p.134.
[504] OPG website, retrieved May 16, 2017 <http://www.opg.com/generating-power/nuclear/nuclear-waste-management/Pages/assuring-the-future.aspx>

8.1.19 The reason this is important is that the fundamental difference between cash and accrual ratemaking, in this context, is whether OPG should collect additional funds from customers for nuclear liability costs that it will not in fact use – now or in the future - to cover nuclear liability costs. Should ratepayers pay OPG $425 million extra so that it can use that money for its other priorities, rather than set it aside to protect future generations?

8.1.20 ***The Province Has Occupied This Field.*** Thankfully, the Board does not have to determine the appropriate amount that OPG should either spend today, or set aside for the future. The Province has already established a comprehensive system, under ONFA, to ensure that the appropriate amount of funds is set aside for the future costs. Further, that same system requires OPG to pay certain categories of costs (LILW[505] costs) on a current basis, and does not require OPG to set aside funds for those costs, because they are required to keep them up to date on a current basis.

8.1.21 In our submission, the government has already made a conscious decision as to the appropriate way to implement intergenerational equity, ensuring that the amounts paid by current customers, and the amounts borne by future generations, are properly and fairly aligned.

8.1.22 This system for protecting future generations is not a slapdash operation. Third party custodians hold segregated funds worth more than $19 billion dollars currently to cover future costs[506]. A system to ensure independent and thorough review of future costs on a periodic basis, and to update the future liabilities, has been established. Decisions with respect to discount rates, and future unit costs, and timing, have been made, and are reviewed at least once every five years.

8.1.23 Perhaps more important, this system is entirely out of OPG's hands. OPG does not have a discretion as to how much it contributes to the segregated funds. It cannot use the money in the funds for anything other than nuclear waste and decommissioning. The funds are separately audited, and are completely separate from the money OPG has available to it for operations.

8.1.24 What the Province did, in ONFA, is not just accept the decisions of accounting bodies. Rather, the Province accepted its fundamental responsibility to ensure that, when the time comes to dispose of this stuff, it is the customers of today, who are benefiting from nuclear power, that end up paying for the waste management and disposal. Our children and grandchildren will not have to pay.

[505] Low and intermediate level waste.
[506] And the costs themselves are currently estimated to be only $16 billion on a net present value basis (Tr21.72,72; J21.3).

8.1.25 To meet that responsibility, the Province established a complete system for determining the future costs, the net present value of those costs, and the amounts that have to be set aside to cover those costs. They did not leave any of this to OPG, or to the OEB, or to anyone else's discretion. The future costs that have to be funded, and the amounts to be set aside to do so, have already been determined.

8.1.26 ***<u>SEC Nuclear Liabilities Recommendation #1.</u>*** In our submission, this Board should accept the intergenerational equity decision of the Province stipulating how much should be set aside for future costs, and which costs should instead be paid on a current basis. The Province accepted its responsibility to deal with these issues, and it did so. There is no apparent reason for the Board to second-guess those decisions, and there is no evidence on the record which would allow the Board to do so.

8.1.27 ***But What About Rates?*** Of course, determining how much should be spent currently, and how much should be set aside for future costs, is not the end of the issue. This Board is not charged with those decisions anyway. This Board is charged with the responsibility to set just and reasonable rates, and in the cost of service context of this proceeding, to determine what costs should be included in those rates to cover present and future nuclear liability costs.

8.1.28 OPG would like to characterize the rate issue as one about accounting principles. OPG is well aware that, in general, the Board defaults to accounting rules to determine rates unless there is a good reason to do otherwise. This makes good sense. The accounting bodies go to a lot of trouble to ensure that costs are calculated, and allocated to periods, in a fair and consistent manner. There is no reason for the Board to reinvent the wheel.

8.1.29 However, the Board also recognizes that the purposes of the accounting rules are not exactly the same as the purposes of the ratemaking rules. This is why, for example, ratemaking does not use deferred tax accounting. The Board has determined that, while it might well be a good idea to treat future tax liabilities as current expenses for accounting purposes, that did not apply equally to rates. From a ratemaking perspective, the question was whether the tax benefits of timing differences would be enjoyed by the shareholders (in increased effective profit) or by the ratepayers (in reduced rates). Similar considerations were brought to the fore when the Board considered the impacts of moving from GAAP to IFRS. Recognition of the particular goals of ratemaking led the Board to required Modified IFRS, in use today by most Ontario utilities.

8.1.30 In this case, the rates question is: Should the Board require ratepayers to pay amounts for nuclear liability costs today when those monies will never actually be spent on nuclear liability costs, either today or in the future?

8.1.31 In our submission, no rationale has been provided for collecting money from customers on this basis. There is no benefit to current customers. They are not getting anything for this extra money. There is no benefit to future customers. Their responsibilities for these costs will be covered by the seg funds. None of this extra money will benefit them, or any OPG customers, present or future. There is only money handed to OPG with absolutely no strings attached[507].

8.1.32 ***<u>SEC Nuclear Liabilities Recommendation #2.</u>*** SEC therefore recommends that the Board allow OPG to include in revenue requirement, with respect to nuclear liability costs including all aspects of nuclear waste management (used fuel, decommissioning, and current waste management), only those amounts that are actually forecast to be applied to current and future nuclear liability costs[508], as stipulated by ONFA.

8.2 ***<u>Revenue Requirement Impact (Issue 8.2)</u>***

8.2.1 This issue relates to the calculation of the amount to be recovered. The issue arises at two levels.

8.2.2 First, if the Board accepts SEC's submission that only amounts that will actually be used for this purpose should be recovered in rates, then there is an issue surrounding what that amount would be. OPG has suggested[509] it is $1,185.9 million. This does not appear to be correct, as we show below.

8.2.3 Second, if the Board decides to allow accrual-based recovery of additional amounts, there is an issue of whether the amounts should be $1,503.3 million, as set out in the evidence[510], or $1,808.1 million, as set out in the Argument-in-Chief of OPG[511].

8.2.4 SEC submits that the appropriate amount to recover from customers over the test period is $1,080.0 million, which is the total of the amounts to be expended by OPG for both Prescribed Facilities and Bruce for current nuclear waste management expenditures, net of the amounts recovered from the seg funds for

[507] We do note the discussion in the hearing about the net liability (underfunded position) on the financial statements of OPG (Tr.21:74-80), where the $16 billion fully funded position in the seg funds compares to $19.1 billion in supposed liabilities on the OPG balance sheet. As it turns out, that is primarily the result of OPG deciding to use a different approach to discount rates to value its future liability, compared to that mandated by the Province in ONFA. As can be seen in J21.3, $2.2 billion of that $3.1 billion difference is the result of a management judgment (Tr.21:78) that the ONFA discount rate is not the appropriate one to use, and therefore the liability should be allocated a higher value. This is just another example of OPG's accounting approach being different from the appropriate approach to the issue. The suggestion in the OPG financials that nuclear liabilities are underfunded is demonstrably wrong, just as the accounting-based costs that OPG proposes to recover from ratepayers for nuclear liabilities are demonstrably wrong, and would in any case not at any time be used to cover nuclear liabilities.
[508] The amounts involved are discussed in more detail in Section 8.2 of this Final Argument.
[509] J20.7, Chart 3, Line 10 plus Line 20
[510] J21.2
[511] Argument-in-Chief, p. 142

those costs, plus the net contributions to the seg funds for future costs over the test period.

8.2.5 There have been a lot of numbers flying around on the issue of nuclear liabilities. A cynic would say that the Applicant may be providing many numbers, in many different ways, to obfuscate the true figures. Whatever the reason for the high level of confusion, it has the potential to make the Board's job more difficult.

8.2.6 SEC has therefore sought to develop a consistent set of figures that reflects the most up-to-date evidence on the record. Those figures are detailed in Appendix B to this Final Argument, which includes information on the evidentiary source of each of the figures in that Appendix. SEC believes those figures to be an accurate reflection of the evidence in this proceeding[512].

8.2.7 The result can be summarized in the following table, which includes both the Prescribed Facilities and Bruce, and represents the totals from the detailed analysis in Appendix B:

Nuclear Liabilities Summary GAAP vs. ONFA (After Tax Impacts)

Description	**2017**	**2018**	**2019**	**2020**	**2021**	**Total**
GAAP Amounts						
Depreciation of Asset Retirement Costs	145.9	145.9	145.9	145.7	76.3	659.7
Used Fuel Storage Variable Expense	93.4	93.4	108.2	102.8	94.8	492.6
Low and Int. Level Waste Mgmt. Exp.	15.0	13.1	15.0	17.4	20.5	81.0
Accretion and Earnings	91.5	83.5	83.3	84.1	88.8	431.2
Total Accrual Amounts (Pre-Tax)	**345.8**	**335.9**	**352.4**	**350.0**	**280.4**	**1664.5**
Tax Impacts	-27.9	-32.3	-19.5	-30.0	-49.0	-158.7
Total Accrual Amounts (After tax)	**317.9**	**303.6**	**332.9**	**320.0**	**231.4**	**1505.8**
ONFA Amounts						
Actual Expenditures	374.5	392.1	431.4	484.6	532.7	2215.3
Contributions to Seg Funds	0.0	0.0	0.0	0.0	0.0	0.0
Recoveries from Seg Funds	154.9	156.6	214.1	271.7	338.0	1135.3
Net Cash Amounts	**219.6**	**235.5**	**217.3**	**212.9**	**194.7**	**1080.0**
GAAP Less ONFA - Difference	**98.3**	**68.1**	**115.6**	**107.1**	**36.7**	**425.8**

512 A live Excel spreadsheet version of Appendix B is being provided to the Board and to parties at the same time as this Final Argument.

8.2.8 We note that the total GAAP amount above is $1,505.8 million, while J21.2 totals those same figures to get $1.503.3 million. The difference appears to be an accumulation of rounding impacts.

8.2.9 ***What Is the ONFA Amount?*** SEC has calculated the actual amounts to be expended on nuclear liability costs in the test period, pursuant to the ONFA rules, to be $1,080.0 million. This is made up of $2,215.3 million of actual spending, less $1,135.3 million forecast to be recovered from the seg funds to cover part of that spending. The contributions to the seg funds, as required by the new ONFA Reference Plan, offset and net to zero.

8.2.10 OPG has calculated the actual expenditures[513] to be $1,185.9 million, comprised of $996.7 million for the Prescribed Facilities, and $189.2 million for Bruce. These figures appear to be incorrect.

8.2.11 The difference lies in the treatment of tax impacts. When calculating GAAP amounts, there is a potential tax impact. The amounts recovered in rates, which are taxable, may not be the same as the amounts actually expended, which are deductible. If one is greater than the other, then there is either a tax shield (if deductions are greater[514]), or an extra tax cost (if the deductions are less[515]).

8.2.12 The same is not true using the ONFA method. The amounts actually expended by OPG for nuclear liability costs – either through direct expenditures, net of recoveries, or through contributions to the seg funds – are deductible for tax purposes. If that is also the amount that is included in rates, and therefore taxable, the two match, and taxable income is zero.

8.2.13 In calculating the ONFA method amounts, OPG has incorrectly made tax adjustments, essentially reversing out the tax impacts in the GAAP method. This is not correct, and effectively double-counts the tax impacts when looking at the difference between the two methods.

8.2.14 Thus, in Line 6 of J20.7, Chart 3, OPG sets out the correct out of pocket costs for nuclear liabilities in the test period for the Prescribed Facilities, i.e. $1,155.1 million. As OPG correctly notes, this is from J20.8, Chart 1, Line 6, which in turn is a total of Lines 4 and 5 in that Chart. Line 5 totals $642.7 million, and took those numbers from N1-1-1, Table 3, Line 15 (amounts recovered from seg funds) minus Line 8 (actual amounts expended). Line 4 totals $512.5 million, which is the new contributions to the seg funds for the Prescribed Facilities.

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[513] J20.7, Chart 3.
[514] Thus, in J21.2, Chart 3, Line 5, the after-tax cost for the Prescribed Facilities, is less than Line 1, theGAAPcost before taxes.
[515] Conversely, in J21.2, Chart 3, Line 15, the after-tax cost for Bruce, is greater than Line 13, the GAAP cost before taxes.

8.2.15 As can be seen, the net amount is fully tax deductible[516]. If that same amount, $1,155.1 million, is included in rates, it will be taxable, but there will be no net tax, because the deductions reduce the gross income to zero of taxable income.

8.2.16 The same is true with Bruce. In Line 16 of J20.7, Chart 3, OPG sets out the correct out of pocket costs for nuclear liabilities in the test period for Bruce, i.e. ($75.1) million negative. That comes from J20.8, Chart 1, Line 14, which in turn is the net of the two lines above it. Line 13 is the money actually spent, less the amounts forecast to be recovered from the seg funds, net $437.4 million. Line 12 is the negative contributions to the seg funds, $512.5 million. For Bruce, OPG is actually in pocket $75.1 million because these two offset.

8.2.17 If you reduce rates by $75.1 million, that reduces the amounts that are taxable. However, if you also receive more from the seg funds than you spend, that net is taxable. The two match, and net taxable income is zero.

8.2.18 The end result is that, if the Board includes $1,080 million in rates to cover the amounts OPG will actually apply in the test period to the costs of nuclear liabilities, there will be no tax consequences. Like any other costs included in rates that are also recognized for tax purposes in the same amount, and at the same time (most operating costs, for example), the Board does not have to be concerned with tax impacts. There are none.

8.2.19 The result of this analysis is that the figure OPG gives in J20.7, Line 24 for the excess of GAAP costs over ONFA costs, $317.4 million, is incorrect. The correct figure, on their numbers, is $423.2 million[517].

8.2.20 ***What is the Appropriate GAAP-Based Amount?*** In J21.2, OPG calculates the GAAP costs associated with nuclear liabilities for the test period with the most up-to-date information available. That figure is $1,503.3 million.

8.2.21 Notwithstanding the evidence, OPG proposes to include $1,808.0 million in the payment amounts[518], and to record the difference, $304.8 million, in the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Deferral Account, for disposition at some later date. Alternatively, they propose to include these amounts in the payment amounts in this proceeding, but deal with the issue solely through Payment Amounts Order process[519].

8.2.22 Thankfully, that is no longer necessary. The Board now has up-do-date evidence,

[516] Which OPG has confirmed: Tr.21:54-56
[517] $317.4 million, less Prescribed Facilities net tax benefit of $158.5 million from Line 9, plus Bruce net tax cost of $264.3 million from Line 19. After adjusting for the accumulated rounding differences, this is the same number that SEC has reached in Appendix A.
[518] The figure is calculated in C2-1-2, Chart 1
[519] J21.2

on both a GAAP and an ONFA basis. The Board can make a determination on the evidence before it.

8.2.23 ***Is There A Potential Compromise Here?*** What concerns SEC here, however, is that the request to collect an additional $304.8 million appears to be nothing more than a deliberate straw man. Notwithstanding the protestations of the witnesses[520], and the avoidance of the issue in the Argument-in-Chief[521], there is no actual justification for including this excess amount in rates.

8.2.24 The apparent reason for this is to present the Board with a ready-made compromise. OPG is asking to collect $1,808 million in rates, but will only actually use $1,080 million to fund nuclear liabilities. Rather than whacking OPG for the full $728 million difference, the Board is presented with the opportunity to "save" the ratepayers $304.8 million, while still leaving the remaining $423.3 million in OPG's hands. It also allows the Board to be "consistent" with the EB-2007-0905 decision, while still charging to the ratepayers' rescue[522].

8.2.25 If the Board were even remotely considering this, SEC urges the Board in the strongest possible terms to reject this Devil's bargain. The $304.8 million that OPG is inviting the Board to save the ratepayers is money the ratepayers would be getting anyway, one way or another. There is no savings there at all. Further, the $423.3 million that OPG is proposing to collect, in addition to the money it will spend on nuclear liability costs, will still be money paid by the customers for nothing. It will still be free money to the utility.

8.2.26 SEC submits that the claim of $1,808 million should be seen by the Board as not a serious ask, and should be summarily rejected.

8.2.27 That leaves the Board with the true – and tough – decision. Does the Board follow past practice, and allow OPG collect $423.3 million that provides no benefit to present or future ratepayers, and will not be spent in any way related to nuclear liabilities? Or, does the Board insist that the money collected from ratepayers for nuclear liabilities must actually be spent on that, and therefore only that amount can be included in rates?

8.2.28 SEC submits that the Province has established a system for ensuring that future generations do not bear the costs of our current use of nuclear power. It is a comprehensive system, and there is no doubt that the ratepayers today should pay all of the costs under that system. Anything more than that, however, is not properly charged to ratepayers, as no ratepayer will never benefit from that excess amount.

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[520] "Everything is happening so fast". See Tr.21:45
[521] Argument-in-Chief, p.142
[522] The word "brazen" comes to mind

8.2.29 SEC therefore submits that the amount included in rates for nuclear liabilities should be $1,080 million.

9 VARIANCE ACCOUNTS (Issue 9)

9.1 *Proposed Variance Accounts (Issue 9.1)*

9.1.1 ***Nuclear ROE Variance Account.*** OPG is proposing to establish a variance account to record the nuclear revenue requirement impact of the difference between the Board's ROE set in this proceeding for the test period (8.78%), and the actual ROE that the Board sets annually for all utilities.[523] The Board should deny this request as it is inconsistent both with the Board policy and with the intent of O.Reg 53/05.

9.1.2 As discussed earlier with respect to the proposed mid-term adjustments to the production forecast, the Rate Handbook discusses its expectations regarding adjustments in Custom IR application. The Rate Handbook specifies that it does not "expect to address annual updates to cost of capital" and that "new deferral or variance accounts should be minimized" in Custom IR applications.[524]

9.1.3 OPG is not seeking to adjust the ROE annually, but only because O. Reg 53/05 requires the Board to set the nuclear revenue requirement on a 5 year basis. The purpose of the Rate Handbook restriction on adjustments is not about simply wanting to avoid annual applications, but to reinforce the Board's comments in the RRFE and many decisions that the Board expects a distributor to manage within the rates (and thus revenue requirement) given that actual costs and revenues will vary from forecast.[525] OPG has not provided any rationale for why the ROE should be any different. It should not be adjusted. Like the production forecast, there is no exceptional circumstance.

9.1.4 Further, the language of O.Reg 53/05 reinforces why the Board should not approve the proposed variance account. Section 12(v)(i) of the regulation requires the Board to set revenue requirement on a 5 year basis for OPG's nuclear facilities.[526] This is a clear indication that the Board should avoid, unless necessary, approving deferral and variance accounts to track differences in parts of the revenue requirement that it would not otherwise have approved if the regulatory restriction was not in place. O.Reg 53/05's intent, similar to the Rate Handbook, is to set the revenue requirement for 5 years. The variance account is an attempt to use another mechanism to indirectly do what it cannot do directly.

[523] Argument-in-Chief, p.152-153; H1-1-1, p.31
[524] *Handbook to Utility Rate Applications*, October 13 2016, p.26
[525] See *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* October 18, 2012, p.19; *Decision and Order (*EB-2014-0101 - Oshawa PUC), November 12 2015, p.6
[526] O.Reg 53/05, section 12(v)(ii)

10 PAYMENT AMOUNTS – METHODOLOGIES (Issue 11)

10.1 *Hydroelectric Rate-Setting Methodology*

10.1.1 There appears to be common ground among all parties that, while IRM is intended to decouple costs and rates, it is also designed to ensure that the revenues provided to the Applicant each year are sufficient to cover their reasonably incurred costs, including an incentive to improve profits through driving cost or output efficiencies. Ms. Frayer calls it a "glide path"[527], and that's probably an apt description.

10.1.2 This is completely consistent with the Board's approach to IRM, and in this context it is important to note that the Board's IRM policies are at the leading edge of North American jurisdictions. While there is always room to learn from the practices and experiences of other jurisdictions, the Board has a long history with IRM in a number of different forms. It will be more often the case that other jurisdictions will learn from the OEB, than that the OEB will learn from them.

10.1.3 We are therefore treating this Final Argument as a continuation of the Board's long-running policy discussion on IRM and its uses. We are skipping the basics, and focusing on the unique aspects of IRM in this case relative to others.

10.1.4 Against that backdrop, it would appear to us that the following issues arise in applying IRM concepts to OPG's hydroelectric Prescribed Facilities:

- ***(a)*** Inflation factor;
- ***(b)*** Productivity factor;
- ***(c)*** Stretch factor;
- ***(d)*** Application of changes in equity thickness to hydroelectric;
- ***(e)*** Retention of the 2014/15 ROE for the Test Period;
- ***(f)*** Interaction between the CRVA and the IRM formula.

10.1.5 We will deal with each of those in turn. We should point out that the other issue that commonly arises in price cap IRM proposals is base year adjustments, but as noted in Section 10.8 of this Final Argument, that issue has been settled in full.

[527] Tr.10:68

10.2 *Inflation Factor*

10.2.1 On behalf of OPG, London Economics International (LEI) did an analysis of the appropriate inflation factor to use in an I-x price cap formula for hydroelectric. Their only report is in the form of a presentation to stakeholders, which has been filed in evidence[528]. The Board's expert, Dr. Lowry of Pacific Economics Group (PEG), has not provided an opinion or expert evidence on the inflation factor.

10.2.2 On the inflation factor criteria, LEI said in their report that[529]:

> *"Selection of inflation indices for the I factor should be done on the basis of objective criteria. 1. Relevance to utility costs. Does it closely reflect the utility's observed cost pressures?"*

10.2.3 Questioned about this in the hearing, Ms. Frayer admitted that, while all of the six criteria identified are used (and important), the choice of cost pressures as item 1 is consistent with its priority[530].

10.2.4 Consistent with LEI's position, SEC believes it is important to look at the key cost pressures underlying OPG's hydroelectric payment amounts. There would appear to be four legitimate components[531]:

(a) ***OM&A – Compensation.*** The amount in base rates is $188M, which is about 14% of total revenue requirement.

(b) ***OM&A – All Other***. The amount in base rates is $147M, which is about 11% of total revenue requirement.

(c) ***Gross Revenue Charge.*** The amount in base rates is $350M, which is about 25% of total revenue requirement.

(d) ***Capital, including Depreciation, Interest, ROE, and PILs***. The amount in base rates is $651M, after the tax adjustment agreed in the Settlement Agreement, which is about 50% of total revenue requirement.

10.2.5 ***OM&A - Compensation.*** What LEI proposed is that, for the compensation component of OM&A, the AWE index, used by the Board in IRM4 under the RRFE, should be used here as well. This appears to be uncontroversial. While there is some concern that OPG has compensation costs that are out of control, and therefore past OPG history is not indicative of reasonable compensation levels going forward, that is not

[528] Ex. A1-3-2, Attachment 3
[529] Page 4. Also included in K10.4, p.20
[530] Tr.10:70
[531] The figures in this section are from K10.5, p.5, and were provided by the Applicant.

an issue for this proceeding, for two reasons:

(a) To the extent that base rates include compensation levels that are unreasonably high, that issue has been settled without an adjustment to those rates.

(b) To the extent that OPG's rate of increase in compensation has been high (and it has[532]), LEI is not proposing to follow the OPG rate of increase, but instead to use AWE, which is 2.33% vs. the 4.37% that OPG has experienced over the same period.

10.2.6 SEC therefore concludes that using AWE for the compensation component of rates, which is about 14%[533], is appropriate.

10.2.7 ***OM&A – All Other.*** LEI has proposed that the generic cost pressures for this segment of costs be equated to GDP IPI FDD, which the Board also uses in IRM4, and has used in other IRM decisions. One of the key advances this Board has made in IRM has been to reject CPI-based inflation factors, which are not indicative of utility cost pressures, and to move to the GDP IPI metric, which captures underlying cost pressures within the economy. While the Board was not the first to do this, it was an early adoptee.

10.2.8 SEC agrees that GDP IPI FDD is an appropriate inflation factor for the bundle of OM&A costs that are not directly related to OPG's compensation of its employees.

10.2.9 ***Gross Revenue Charge.*** LEI has proposed that GDP IPI FDD also apply to the GRC, essentially lumping it in with all costs that are not OM&A - Compensation.

10.2.10 This is a major cost for OPG, and its expert LEI initially appeared simply not to understand what it was all about[534]. Then, after insisting that she needed time to consider it, Ms. Frayer came back to say that the GRC was just like PILs, and therefore it was appropriate to apply GDP IPI FDD to this cost as well[535]. In fact, the surprising exchange is worth looking at:

> "*MR. SHEPHERD: Well, how are PILs the same? PILs, if I'm correct, track exactly to ROE, and ROE is a cost of capital. So as capital goes up, ROE goes up; right?*
> *MS. FRAYER: Sorry, what was the last part? As capital goes up ROE goes --*
> *MR. SHEPHERD: As your rate base goes up your ROE goes up, and*

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[532] J10.4, although note that the results in J10.4 do not include adjustments for disallowances of compensation costs for regulatory purposes by the Board.
[533] We note that LEI used 12%. This does not appear to be correct, based on the revenue requirement grounding base rates.
[534] Tr.10:79 et. seq.
[535] Tr.10:90-94

> *therefore your PILs goes up, so if there is an inflation factor associated with capital, then that will drive ROE and it will drive PILs, right?*
> *MS. FRAYER: Yes.*
> *MR. SHEPHERD: Exactly the same way.*
> *MS. FRAYER: Yes."*[536]

10.2.11 In this respect, it appears that Ms. Frayer has completely misunderstood the GRC and how it works.

10.2.12 As the Applicant admits[537], the GRC is a fixed charge based on production, and subject to a low minimum threshold the unit cost is the same. It does not vary based on income, or revenue requirement, or rates, or any other cost escalators. It does not in fact vary with inflation. If OPG generates another MWh, it has to pay another $10. It is uncomplicated.

10.2.13 What this means in the real world is that the inflation pressure on the GRC is zero. Sell more of your product, of course you have more costs. But if the costs rise exactly in accordance with units sold (in this case kwh.), then the inflation impact is zero.

10.2.14 Further, the Applicant and its expert LEI have provided no evidence to suggest that the GRC will change at any time in the test period. It has been a constant amount for some time. The Government has made no statements that it is considering increasing the rate.

10.2.15 This is not at all like PILs. The rate on PILs is assumed to be the same over the test period. However, the revenues and expenses, and therefore net income, to which PILs is applied are expected to increase with inflation. Thus, the dollar amount of PILs will also increase with inflation.

10.2.16 The GRC is not applied to revenue, or profits. It is applied to production, based not on dollars but on units of energy. Unless those units of energy increase, the GRC will not increase. Further, if those units of energy increase, the revenues of OPG will increase at the same rate.

10.2.17 The initial position of LEI appeared to be that "we just lumped everything together, including GRC". Later, called on that obvious error, LEI sought to justify the inflating of the GRC component of rates by analogy to PILs.

10.2.18 LEI is wrong on both counts. Just as it is appropriate in this particular case to use a different inflation factor for Compensation, because it grows more rapidly than overall costs in the economy (and it is a material component of OPG's costs), it is also

[536] Tr.10:93-4
[537] Kicking and screaming, as usual.

appropriate to use an inflation factor of zero for the GRC, a cost that is not expected to change, on a unit basis, over the test period.

10.2.19 SEC therefore submits that the inflation factor for the GRC should be zero, and the formula should adjust for this.

10.2.20 SEC notes that OEB Staff, in their submissions, have proposed that only half of the GRC be treated as having 0% inflation increase. Their theory is that zero-inflation costs are a factor in all businesses, and therefore GDP IPI will capture some of this effect already. The adjustment for the OPG inflation factor is simply to recognize that the percentage of OPG costs that have zero inflation is likely much higher than the economy-wide percentage of that category of costs[538]. They further make an analogy to the Board's treatment of PILs in the IPI[539].

10.2.21 These arguments in favour of a 50/50 split are without foundation.

10.2.22 The GDP IPI would, of course, capture all aspects of inflation. However, that would include wage inflation. Therefore, on OEB Staff's argument, some of the additional increase in costs seen in AWE is already captured in GDP IPI, and so applying AWE to 100% of compensation costs would be double counting. OEB Staff does not propose to make that adjustment, with the result that their inflation factor is, by their own logic, too high.

10.2.23 The reality is that the Board has to either disaggregate the inflation impacts, and apply different rates to the components of costs to which they relate, or has to take an economy-wide measure, and assume that the variations between inflation rates of different components of costs will be reflected in that rate.

10.2.24 In this case, using AWE for Compensation, and using 0% for GRC, as we have proposed, covers 39% of revenue requirement for which the Board knows the inflation drivers. The remaining 61% of revenue requirement does not have specific inflation drivers that can be identified. That is why GDP IPI is used. That will still include a mix of inflation forces (capital has compensation and zero inflation costs as well, for example), but there is no reason to believe that the mix of forces is any different from the economy as a whole.

10.2.25 SEC therefore submits that, on the theory that zero inflation costs are already included in GDP IPI, OEB Staff is simply inconsistent and incorrect.

10.2.26 The Board knows that 25% of OPG revenue requirement has zero inflation pressure. To use anything other than 0% as the inflation factor for that component would be overstating inflation. SEC submits that the GRC component of revenue requirement

[538] See OEB Staff Submissions, p.148
[539] *Ibid*, p.149

should be inflated at a 0% rate[540].

10.2.27 ***Capital.*** There has been an extensive debate in this proceeding about how "cost pressures" influence the costs associated with the capital component in rates. In the end, we have concluded that Dr, Lowry of PEG is right. While there is a question of whether costs for the capital assets of a hydroelectric generation business rise at the same rate as other companies in the economy, that is not a generic impact. That is an impact related to productivity, rather than inflation.

10.2.28 Essentially, if OPG's hydroelectric operations spend money on capital, there will be inflationary cost pressures on that spending. All inputs will be subject to those inflationary pressures. You can't get away from it.

10.2.29 Conversely, the issue of whether OPG will spend less on capital (as in, units of activity) due either to the fact that it is a hydroelectric business, or the unique aspects of OPG's business, is an issue of productivity. To the extent that the cost changes (increases or decreases) of a business are more or less than the cost changes of the economy as a whole, that is captured in the productivity component of IRM, not the inflation component.

10.2.30 Thus, SEC accepts that the costs associated with capital inflate in the same manner as other costs in the economy. While the regulatory process may reflect those costs in rates in a particular way, those inflationary cost pressures on capital will, over the long term, match the inflationary cost pressures on rates, and conceptually the numeric results should be the same over time.

10.2.31 SEC therefore agrees with LEI and PEG that application of the GDP IPI FDD inflation factor to the capital components of rates is appropriate. We will argue, below, that productivity of hydroelectric facilities is better than inflation, consistent with PEG, and largely because of the natural decline in capital inputs. However, at a strict inflationary level, SEC accepts that the inflationary cost pressures on capital are the same as on other costs, and should be reflected in the IRM formula accordingly.

10.2.32 ***Inflation Factor – Conclusion.*** SEC therefore concludes that the inflation approach used by LEI is appropriate except for GRC. It is clear that the GRC is a category of costs that is not subject to inflation pressures, and therefore that component of costs should be assigned an inflation factor of zero.

10.2.33 SEC would therefore calculate the inflation factor for 2017 as follows[541]:

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[540] SEC has had an opportunity to review a draft of the LPMA, and is aware that LPMA submissions are proposing an alternative approach, in which the GRC is treated as a Y factor. SEC believes that the LPMA solution is actually a more elegant and technically correct solution. However, SEC is still proposing the zero rating approach in this Final Argument because it tracks the OPG proposal more closely, and because it allows the Board to have more than one alternative solution to this issue.

[541] Data taken from OEB Staff Submissions, Table 37, p.149.

(a) For the 14% of revenue requirement and therefore base rates that is OM&A – Compensation, AWE, which is 2.574%. This component of the inflation factor is 0.36036%.

(b) For the 25% of revenue requirement and therefore base rates that is OM&A – GRC, 0%.

(c) For the 61% of revenue requirement and therefore base rates that is OM&A – Other and Capital, GDP IPI, which is 1.619%. This component of the inflation factor is 0.98759%.

(d) The resulting inflation factor for 2017 is therefore 1.34795%, rounded to 1.35%.

10.2.34 SEC notes that its inflation factor, 1.35%, compares to the inflation factor proposed by OPG of 1.8%, and the inflation factor calculated by OEB Staff of 1.53%[542]. The effect of using what we view as a more correct calculation of the inflation factor, as compared to either OEB Staff or OPG, is that customers would pay approximately $40 million less in hydroelectric rates for the 2017-2021 period than OEB Staff is proposing, and about $165 million less in rates for that period than OPG is proposing.

10.3 ***Productivity Factor***

10.3.1 The situation with the productivity factor is a little more complicated.

10.3.2 Let's start with the reality of the empirical data. Productivity each year is all over the map, a very volatile figure because hydrology will dictate material changes in outputs[543]. The theory of productivity measurement in hydroelectric generation is that, over a long period of time, volatility will express itself as a trend that is more reliable than the annual amounts. None of the witnesses provided any evidence that is the case, nor any evidence that the underlying trends in outputs will be productivity-driven, with no other factors involved.

10.3.3 It is perhaps no accident that I minus X has not been applied to hydroelectric generation rates in North America.

10.3.4 Once you get past the fact that the raw data has no obvious trends, and there are no empirical explanations for the volatility (it never tracks hydrology at a level of statistical significance, for example), you are still left with data. That data is still useful, but only if all hydroelectric businesses have a similar cost trend, with identifiable independent variables.

[542] Although OEB Staff appears to round it down to 1.50%. See Table 39 on p.159 of the OEB Staff Submissions.
[543] We have reviewed a draft of the Energy Probe submissions, which includes a good discussion of the volatility question, and its technical and practical implications. While we do not agree with the conclusions that Energy Probe draws on every specific point, we think this analysis is useful for the Board, and is generally correct.

10.3.5 Aside from hydrology, which doesn't explain enough of the volatility in the raw data, the experts who testified in this proceeding have not identified variables that can explain the rest of that volatility, and therefore the reasons for the trends that are apparently seen in the data.

10.3.6 So that leaves the Board with two types of inputs for its decision.

10.3.7 First, the Board has the productivity calculations of the two experts, which are markedly different despite having studied very similar proxy groups. This is in large part due to different methods of looking at productivity, discussed below.

10.3.8 Second, the Board has its own understanding of how OPG's costs will grow over the Test Period in its hydroelectric Prescribed Facilities. The non-capital component is easy. The capital component is more difficult.

10.3.9 ***What Do the Experts Say?*** The first part of that debate is pretty simple, really. PEG came up with a productivity factor of 0.29% for its proxy group. LEI came up with a productivity factor or -1.04 for its proxy group[544].

10.3.10 The difference between the two is not in their proxy groups, but rather in their methodologies. LEI calculated production based on how many units (MWh) of energy were produced for each unit (MW) of capacity available. PEG calculated production based on how many units (MW) of capacity were produced for each dollar of investment in generation capacity[545].

10.3.11 One test of which method is right is the Niagara Tunnel. The LEI method does not consider the investment by OPG and its ratepayers in the Niagara Tunnel to increase productivity, since it did not increase capacity. The fact that more units of energy were produced from the turbines because of the increase in water flow is completely ignored[546]. On the other hand, the PEG approach treats the Niagara Tunnel, and any other dollar investments to improve the outputs from a utility's capacity, as part of the cost/benefit equation. PEG recognizes that ratemaking is about dollars, and productivity measures must be translatable into dollars to be useful to the regulator. However, PEG then does not reflect the increased energy outputs from Niagara as an improvement in productivity, because the capacity has not increased.

10.3.12 Thus, both methods have fundamental problems, but they are different problems.

10.3.13 PEG's method has a problem because it assumes that MW of capacity is a good proxy for MWh. As OEB Staff correctly points out, MWh is actually the best output measure because it is the basic product hydroelectric generators produce. The reason PEG uses

[544] Tr.11:7; M2, p.5
[545] M2, p.19-20
[546] This is correctly criticized by PEG.

MW rather than MWh as its output is that MWh is very volatile due to hydrology. PEG treats MW as essentially a more stable proxy for MWh[547].

10.3.14 Generally, speaking, MW is a stable proxy for MWh, because circumstances in which energy production can be increased, without increases in capacity, and independent of hydrology or system demand, are uncommon. It can happen. Refurbishing a turbine can make it more efficient at the same capacity rating. A new tunnel can deliver more water to existing Sir Adam Beck turbines. These things don't happen very often, so for any given proxy group the difference between MW and MWh as an output will mostly be MW's greater stability.

10.3.15 LEI also claims that PEG's method has a problem because its use of dollars in the inputs requires a depreciation of assets, and hydroelectric assets are typically closer to a one hoss shay depreciation method. While in theory this is correct, we agree with OEB Staff that, when considering a portfolio of hydroelectric assets, as is the case with OPG and almost all of the proxy group, geometric decay depreciation more closely models the decline in the portfolio than does one hoss shay[548]. Therefore, the criticism of PEG based on using monetary inputs is not well founded.

10.3.16 LEI uses a methodology that has not one, but two fatal flaws.

10.3.17 First, LEI uses MWh as the output. As noted earlier, this means that there is an implicit assumption in LEI's study that, over their 13 year study period, there was not sufficient hydrological volatility or trends to skew the productivity results. In effect, hydrology is treated as a constant (or random) for LEI. This is unlikely to be correct.

10.3.18 For example, some of the LEI proxy group have a common hydrology impact over the study period, and as OEB Staff pointed out in cross-examination[549], LEI had no way of adjusting for the possibly material impact of this influence.

10.3.19 Second, LEI uses MW as its input, with the necessary result that no capital productivity improvements are captured. LEI in effect assumes that the cost of a unit of hydroelectric capacity is the same for all companies in the proxy group. If one company adds capacity at a lower cost than its peers, that is not considered to be a productivity impact.

10.3.20 For a purist, LEI's argument in favour of a solely physical quantities approach to productivity is not wrong. Most economists would say that getting more units of production out of the same productive capacity is a classic measure of productivity.

[547] The obvious best output would be Mwh normalized for water conditions. It appears to be common ground between the experts that the US companies in the proxy group do not make that category of information – or the data from which to calculate it easily – available publicly.
[548] See OEB Staff Submissions, p.154
[549] Tr.9:53-59

10.3.21 But this is not an economics class. This is a rate case. Productivity matters to the Board because of dollars. There is a reason why regulators rarely use entirely physical quantity productivity methods in their rate-setting processes, and the OEB has rejected that approach in the past[550]. Given the capital intensive nature of the hydroelectric business, a productivity study that ignores productive use of capital dollars is not particularly helpful.

10.3.22 Given the flaws in both studies, SEC agrees with OEB Staff that the PEG study is more helpful to the Board, for two reasons:

(a) The MW output measure is likely to be closer to normalized MWh, the optimum output measure, than non-normalized MWh will be. All parties appear to agree that non-normalized MWh has volatility that limits its correlation with normalized MWh.

(b) The monetary input measure is more suitable in the rate-setting context than the physical input measure, both because it captures efficiencies in the use of capital dollars, and because on a portfolio basis geometric decay more closely models depreciation than does one hoss shay.

10.3.23 SEC therefore submits that the Board should reject the LEI study, and should prefer the PEG study, based on those methodological differences.

10.3.24 ***What Are the Real Cost Pressures?*** There is a second reason why the Board should prefer the PEG study to the LEI study, and that is that the PEG study more closely reflects the real world pattern of capital costs faced by a hydroelectric producer operating in a stable environment, as OPG expects to do.

10.3.25 SEC put before the Board the actual pattern of capital costs OPG has experienced in its hydroelectric business since 1999[551].

10.3.26 What these two tables demonstrate is that in 1999 the OPG hydroelectric rate base was $7.2 billion[552]. By 2012, with OPG carrying on a stable hydroelectric business, the rate base had dropped to $6.2 billion[553], a compound annual decline in the capital base of 1% per year. Then OPG added the Niagara Tunnel in 2013, a highly unusual capital addition. After that adjustment, which increased rate base to $7.6 billion[554], rate base resumed its downward trajectory, so that in 2015 it was $7.4 billion[555]. That is a 1.35% decline each year.

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[550] See OEB Staff Submissions, p.153, for relevant references.
[551] JT3.16, pages 3 and 4, included in K10.4 at p. 26-27.
[552] Gross assets of $7,266.4M less accumulated depreciation of $91.5M.
[553] Gross assets of $7,750.2M less accumulated depreciation of $1,544.0M.
[554] Gross assets of $9,300.3M less accumulated depreciation of $1,676.3M.
[555] Gross assets of $9,353.2M less accumulated depreciation of $1,940.4M.

10.3.27 Throughout this period, the production from the hydroelectric facilities has not changed dramatically, except for the impact of the Niagara Tunnel (and, of course, for changes in hydrological conditions, in respect of which OPG is protected by a variance account). The result is that the net capital base for OPG generation has declined over time.

10.3.28 This is broadly consistent with the PEG study. PEG calculated that, on a total factor productivity basis, the proxy group had a 0.29% TFP. OPGs capital cost has actually been dropping by 1% per year, which with capital at 50% would translate into 0.50% productivity if all other costs were at zero productivity[556].

10.3.29 SEC believes that the declining rate base for a hydroelectric producer like OPG with a stable operation is indicative of the natural productivity – in a dollar and ratemaking sense – that arises in a capital intensive business. As the company recovers some of its capital costs through revenues (i.e. by recovering depreciation), the amount the company has left invested in its assets goes down. If production does not decline at the same rate – something that both LEI and PEG believe is true in a hydroelectric business – the output the company can get from each unit of invested capital improves over time. The OPG figures prove that is the case[557].

10.3.30 Looking at OPG's declining rate base is not a substitute for conducting a proper TFP study, and SEC would not suggest that the Board use this kind of analysis to estimate an X factor. However, the Board can and should use it to understand the underlying reasons why the PEG approach and results are more consistent with real world conditions than the LEI approach.

10.3.31 Experts like LEI would like the Board to think that the methods and jargon of their specialized area of economics is a closed and integrated system, and the Board can't be selective in how they view economic analysis. This is wrong. The Board must, in our view, always look at expert analysis through a ratemaking lens. Analysis that reflects the reality of utility costs will be the most useful to the Board. Analysis that rejects the importance of real utility cost trajectories – such as the LEI study – will be less useful.

10.3.32 In this situation, the Board can see that there is a natural tendency in a hydroelectric business to be more cost-effective over time, as the annual cost of capital assets to be

[556] We understand that this is a simplistic approach, and is not reflective of a proper productivity calculation. However, it is a useful sanity check, especially given the LEI calculation of negative productivity for a proxy group of hydroelectric generation companies.

[557] This is really pretty basic, when you think about it. Many capital intensive businesses see an increasing net profit over time because of the net decline in the cost of the capital assets, both in real and nominal terms, over time. For example, when the economics of a rental apartment or office building are calculated, it is well known that the increase in operating costs is not as great as the decrease in the real capital costs relative to inflation. That is why investors in those assets are willing to be cash poor in the early years. Over the long term, the returns improve as revenue increases outstrip total cost increases.

included in rates goes down. The PEG TFP results are consistent with that reality. The LEI results are not.

10.3.33 ***Productivity Factor – Conclusion.*** SEC therefore submits that the Board should accept the productivity factor of 0.29% estimated by PEG.

10.4 ***Stretch Factor and Resulting Formula***

10.4.1 SEC agrees with OPG, and with OEB Staff, that a stretch factor of 0.30% is appropriate for OPG's hydroelectric IRM formula. All of the evidence appears to indicate that, in its hydroelectric business, OPG is an average performer relative to its peers.

10.4.2 The result of the three components is that SEC proposes an I-X result for 2017 of 0.76%, made up of an inflation factor of 1.35%, less a productivity factor of 0.29%, less a stretch factor of 0.30%.

10.5 ***Equity Thickness***

10.5.1 OPG proposes to apply its proposed new equity thickness of 49% to its hydroelectric business as well, through the use of a deferral account. The impact of that is to collect an additional $114.3 million from customers during the period 2017-2021[558].

10.5.2 Elsewhere in this Final Argument SEC has argued that OPG's equity thickness should not increase. If the Board accepts SECs argument on that point, then the equity thickness for hydroelectric would also not change.

10.5.3 In the alternative, if the Board concludes that it will allow an increase in equity thickness, SEC submits that change should not apply to OPG's hydroelectric business until the next rebasing. We make this submission for two reasons.

10.5.4 First, it is not appropriate to change the equity thickness for a utility except as part of a cost of service or rebasing proceeding. OPG is seeking, with its proposal to use a variance account, to get an increase in its hydroelectric equity thickness through the back door. It argues that because a) nuclear is rebasing in this proceeding, and thus can consider whether its equity thickness is right, and b) the Board prefers to set ROE for OPG as a whole, rather than each technology-driven business, therefore it is appropriate to change the equity thickness for hydroelectric. This is, in all respects, nothing more than a "tag along" argument.

10.5.5 This is not realistic. The Board considers equity thickness in a cost of service context because it is appropriate to deal with all actual costs at the same time. It is normally not appropriate during an IRM year to cherry pick individual cost categories and adjust

[558] Tr.21:17. What OPG actually admitted to was $22.8 million per year for five years, which is $114.0 million.

them.

10.5.6 Second, and essentially flowing from the first, OPG proposes to keep the ROE from its rebasing year, but selectively change the equity thickness only[559]. The ROE embedded in rates is 9.33%, but the current Board allowed ROE is 8.78%. The difference between the two is $25 million a year for the OPG hydroelectric business[560], or $125 million over the period 2017-2021.

10.5.7 Thus, OPG wants to suck and blow at the same time. On the equity thickness, which if their proposal is approved would increase their revenue, they want to ignore what is embedded in rates and take an extra $114 million from ratepayers. On the ROE rate, which if updated would decrease their revenue by $125 million, they insist that the amount embedded in rates is just fine and should not be changed. In order to avoid adjusting one and not the other in 2017, they propose a variance account so that they can achieve exactly that result, but indirectly rather than directly.

10.5.8 The Board should reject this cynical and self-interested approach to the regulatory process. If any change in equity thickness is to apply to hydroelectric before 2021, it should be applied through an adjustment to base rates for 2017, and at the same time the ROE should be updated, also as an adjustment in base rates[561].

10.5.9 SEC notes that the idea that OPG would get the benefit of the increased equity thickness, but not the cost of the declining ROE, is so inappropriate that it is likely just another straw man, deliberately inserted by OPG into its application so that the Board will have something to deny them without actually costing OPG anything. If you know a proposal is untenable, and you propose it anyway, that is just playing regulatory games. In SEC's submission, the Board should have little patience for that kind of tactic.

10.6 ***Adjustments to ROE***

10.6.1 SEC has noted elsewhere that it is not appropriate to adjust the ROE for OPG's nuclear business annually as proposed by OPG. The ROE should be fixed in 2017, the rebasing year, at 8.78%, and kept constant throughout the IRM term.

10.6.2 On the same basis, SEC agrees that the ROE in the rebasing year for hydroelectric should be fixed at 9.33%, the rate embedded in base rates, and kept constant throughout the IRM term. In fact, this is a settled issue.

10.6.3 However, if the Board determines that it should adjust the ROE annually for nuclear,

[559] Tr.21:16
[560] J20.2
[561] Base rates are, of course, settled, so this would be a problem. However, the essence of the point is still valid. Equity thickness should not be updated unless ROE is also updated.

as proposed by OPG, then the ROE for hydroelectric should be adjusted at the same time, and in the same way (i.e. through a variance account). That would include 2017, where the hydroelectric ROE would drop to 8.78%. Thereafter, if the Board accepts OPG's proposal to adjust nuclear ROE, the ROE for the two businesses should be the same, as it has been in the past, and both should be adjusted each year in accordance with the Board's approved levels.

10.6.4 SEC notes that fixing ROE now, and then not changing it during the IRM term, is the best solution for both hydroelectric and nuclear. It is only if the Board is considering annual changes that, in our submission, annual changes for both businesses is the appropriate result.

10.7 ***IRM vs. CRVA Interaction***

10.7.1 The capital component of the IRM formula for hydroelectric is complicated by the existence of the CRVA, which allows OPG to recover the revenue requirement impact of certain capital costs outside of the IRM price cap formula. In a price cap environment, that kind of additional recovery is not really appropriate, as Dr. Lowry points out, but because the CRVA is required by regulation, the Board cannot deal with this by simply suspending the CRVA for hydroelectric projects[562].

10.7.2 ***The Original OPG Proposal.*** OPG's original position on the interaction between the CRVA and IRM was that OPG was allowed to recover the revenue requirement impact of any capital projects in excess of the $2 million of CRVA capital projects approved for the rebasing year[563]. The result would have been that essentially all of the planned $335M of CRVA eligible projects[564] would be incremental to the IRM formula.

10.7.3 ***The PEG Solution.*** This position was clearly untenable. As Dr. Lowry correctly pointed out, if a major category of costs is to be excluded from the IRM calculation, then the formula has to be recalculated to be fair. Dr. Lowry's proposed solution was to recalculate the productivity factor in this study excluding a proxy for the CRVA category of capital. Based on his calculations, the productivity factor would have to increase from 0.29% to 0.74% if this category was excluded[565].

10.7.4 SEC estimates that the impact of the 45 basis point increase in the productivity factor would be a decrease in OPG revenues over the period 2017-2021 of $96M[566].

10.7.5 ***The New OPG Proposal.*** OPG later came back with a new proposal, in which they allege that the depreciation embedded in their base rates, escalated at the same rate as

[562] That would likely be the best solution. It is just not a legally allowable solution.
[563] Tr.10:103-4; Tr.10:127-8
[564] IR 11.1-SEC-095 (Updated)
[565] M2, IR 11.1-SEC-001 (Updated)
[566] SEC notes that LEI did not appear to think that any adjustment for the CRVA was required. This is just one more reason for the Board to reject the LEI analysis.

the base rates under IRM, creates an envelope that is available to fund new capital additions of the IRM period. OPG calculated the total capital additions funded in rates as $749.1 million on this basis[567]. Under their new proposal, they would only be allowed to collect the revenue requirement for projects in excess of that amount, and only up to the total of CRVA eligible projects. Further, they would offset this with an annual credit of $0.9M representing the CRVA-specific revenue requirement embedded in base rates (total $4.7M over five years).

10.7.6 Based on their total capital budget of about $950M, of which $335M is CRVA eligible, under the new proposal OPG would be allowed to collect, through the CRVA, the revenue requirement impact of about $200M of projects ($950-$749), or about $31M[568]. The $4.7M embedded for CRVA projects would be deducted, leaving about $26M for the ratepayers to pay at the end of the term, in addition to normal rates.

10.7.7 ***The SEC Analysis.*** SEC put to the OPG witnesses the proposition that the revenue requirement on which base rates are set includes amounts to fund a particular rate base. The nature of the rebasing process, cost of service, is that there are certain categories of costs that are included in rates to reflect "return of capital and return on capital", the classic components of the capital part of ratemaking. OPG agreed in principle that is how capital is recovered in rates[569].

10.7.8 OPG then agreed that, if you add a given percentage to rate base, rates have to go up by the same percentage to be compensatory to the utility, all other things being equal[570].

10.7.9 We then demonstrated, in spreadsheet format[571], that the proposed IRM formula for OPG would form the basis for rate recovery of cumulative increases to rate base of $1,296.6M over the period 2017-2021. That is just simple math. As the funded rate base goes up under the OPG formula, the utility can add capital additions not only to replace the capital recovered through depreciation, but also to drive the increase in funded rate base. The difference between the rate base at the end of the term, without any capital additions, and the rate base funded through the IRM formula, is the amount of capital additions embedded in the IRM funding formula.

10.7.10 The spreadsheet provided to the witnesses during the hearing was based on an annual IRM escalator of 1.50%. SEC in this Final Argument has proposed an annual IRM escalator that would currently be 0.76%. That makes a substantial difference, so the revised calculations are set forth below:

567 H1-1-2, p.8
568 Revenue requirement on $335M is $52M (11.1-SEC-095 updated), so if the spending pattern is similar, $200M has a revenue requirement of $31M.
569 Tr.21:28-29
570 Tr.21:30-31
571 K21.1, p.15

Capital Funded in Rates						
Escalator	0.76%					
Rate Base at Start	7,507.7					
Capital Built Into Base Rates						
Depreciation/Amortization	143.3					
Cost of Debt	199.4					
ROE	315.2					
PILs	78.6					
Total in Base Rates	736.5					
Percentage of Rate Base	9.81%					
	2017	***2018***	***2019***	***2020***	***2021***	***Total***
Funding Envelope	742.1	747.8	753.4	759.2	764.9	3,767.4
Rate Base Without Additions						
Opening	7,507.7	7,364.4	7,221.2	7,077.9	6,934.6	
Depreciation	143.3	143.3	143.3	143.3	143.3	716.3
Closing	**7,364.4**	**7,221.2**	**7,077.9**	**6,934.6**	**6,791.4**	
Rate Base Funded	**7,564.8**	**7,622.3**	**7,680.2**	**7,738.5**	**7,797.4**	
Available Capital Additions	200.3	200.8	201.2	201.6	202.1	1,006.0
Cumulative Additions	**200.3**	**401.1**	**602.3**	**803.9**	**1,006.0**	

10.7.11 What the revised data shows is that, even at the lower escalator proposed by SEC, the IRM formula still allows rate recovery for more capital additions than OPG is proposing, in total, in the IRM period. Using a proper threshold for the CRVA calculation, SEC submits that the CRVA additions will be zero.

10.7.12 OPG agreed with the math, but disagreed with the concept. In their view, only depreciation funds new spending. The fact that the IRM formula also escalates the ROE, PILs, and cost of debt as well should not be considered. Those escalations are to compensate them for the risk that the cost of capital, or taxes, will change over the IRM period[572].

10.7.13 What OPG is referring to is the notion that inflation includes changes in the cost of capital in the economy. Thus, if cost of capital goes up (and therefore ROE and cost of debt and PILs would go up), the IRM formula gives them more money to cover those rising costs.

10.7.14 Their point is well taken, but wrong on the facts of this case. The inflation rate being assumed, by OPG and everyone else, is the current low rate, below 2%. That rate does not include inflation in the cost of capital. The cost of capital in Canada, and

[572] Tr.21:32

embedded in Canadian inflation rates, has been going down over the last several years, and is currently roughly static.

10.7.15 SEC agrees that if the cost of capital rises in Canada, the inflation indicators may reflect that increase in costs, and the inflation component of the PCI will compensate OPG for those increases in cost. If that were to happen, the calculation of capital funded in rates that SEC has proposed would be wrong.

10.7.16 By way of example, if inflation went from 1.6% to 3.0%, based on increases in the cost of capital in the Canadian economy, the SEC model would show that almost $1.6 billion of new capital additions would be funded in rates. That would not be a reasonable conclusion, however. Some portion of the increases in the funding envelope would have to be treated as reflecting increases in the cost of capital.

10.7.17 That, however, is not the current situation. The current situation is that Canadian inflation does not include a component reflecting increasing cost of capital, because right now the cost of capital is static. It is precisely for that reason that the application of the IRM formula allows the Board to estimate whether the level of capital additions funded in rates is sufficient to cover the total proposed capital budget of OPG.

10.7.18 SEC submits that the Board can confidently determine that recovery for at least $1 billion of new capital over the 2017-2021 period is already provided for in the existing rates, and the IRM formula. SEC proposes that the threshold for CRVA recovery be set at that level, rather than at the depreciation level, $749.1M, as proposed by OPG.

10.7.19 With that correction to the threshold, SEC believes that the approach ultimately proposed by OPG for calculation of the CRVA for hydroelectric is appropriate.

10.7.20 SEC notes that over the next five years the actual inflation rate may be different than the inflation rate included in the estimates of capital funding. If it changes, it is likely to be higher. However, in our view if the cost of capital is increasing during that period it would be reasonable for the Board to assume that the additional funding provided by those higher inflation levels is in whole or in part driven by increases in the cost of capital.[573]

10.8 ***<u>Adjustments to Base Payment Amount (Issue 11.2)</u>***

This issue has been settled in full.

[573] LPMA has done a calculation based on the ICM formula. SEC agrees that, although the approach is different than we are proposing, the result is both technically justified, and reasonable.

10.9 *Nuclear Rate-Setting Methodology (Issues 11.3-11.4)*

10.9.1 ***Overview.*** The Board's February 17th, 2015 letter to OPG detailed its expectations regarding the development of its incentive-rate-setting mechanism. In that letter it stated that it "expects OPG to develop…a custom IR framework for its nuclear assets based on the principles outlined in the RRFE."[574] SEC submits OPG's proposal rate-setting framework for its nuclear assets has not met those requirements. OPG has not sufficiently incorporated the Board's expectations for Custom IR into its Application.

10.9.2 OPG's approach to setting its rates based on a Custom IR framework was simply to move to a longer rate-setting term than it had in the past (5 years versus 2 years), and incorporate into a *portion* of its nuclear forecast OM&A costs a stretch factor.[575] This is insufficient and does not meet the Board's requirements for a custom IR. A stretch factor that is built into forecast costs must be comprehensive, and include all aspects of both OM&A and capital spending. Moreover, the stretch factor that should be applied must reflect OPG's most recent accurate benchmarking evidence, as that is most reflective of its actual performance.

10.9.3 OPG is also proposing to adjust its production forecast midway through the 5 year plan term to the mid-term review. Such an approach is not appropriate for a Custom IR application which is premised on the notion that a utility should be able to forecast its costs and revenues over such a period, and live within those forecasts even if the actuals will inevitably vary.[576]

10.9.4 ***Stretch Factor.*** The central component to OPG's proposal for setting its nuclear payment amounts on a Custom IR basis is the inclusion of a stretch factor of 0.3% for a portion of its OM&A costs, its nuclear base OM&A and nuclear allocated corporate support costs. OPG has excluded its proposed capital spending, as well as its outage, project, and centrally held OM&A costs.

10.9.5 SEC submits that the Board should set a stretch factor of 0.6% on all aspects of OPG"s OM&A and capital spending (excluding the DRP).

10.9.6 In setting the stretch factor, OPG modified the Board's framework under the RRFE. That framework assigns distribution utilities to cohorts using a predictive econometric benchmarking model, then assigning them a stretch factor between 0% and 0.6%. OPG used the cohort stretch factor models of assigning itself one between 0% and 0.6%, but instead of undertaking an econometric benchmarking exercise to determine its own predicted costs as compared to its actuals, it used information from its 2015 annual Nuclear Benchmarking Report. Specifically, OPG determined what quartile each of its

[574] Letter from Kristen Walli (Board Secretary), Re: Incentive Rate-setting for Ontario Power Generation's Prescribed Generation Assets (February 17, 2015)
[575] Tr.6:171
[576] See for example the comments in *Decision and Order* (Oshawa PUC - EB-2014-0101), November 12 2015, p.9; *Decision with Reasons* (Hydro One Dx - EB-2013-0416), March 12 2015, p.31

Darlington and Pickering units preformed compared to its peers on a 3-year rolling Total Generating Cost per MWH metric.[577] It then assigned a stretch factor between 0% and 0.6%, i.e. top quartile represented 0%, and then used the Board's 2015 approved production to create a weighted average.[578] Using that information, OPG derived a stretch factor of 0.3%, based on 0.0% (first quartile) performance of Darlington and a 0.6% (fourth quartile) performance of Pickering.

10.9.7 For numerous reasons, OPG's approach is unreasonable and insufficient. SEC does not oppose OPG's use of the Nuclear Benchmarking Report information as the benchmarking needed as the basis for the stretch factor. It does, however, disagree with how that information was used.

10.9.8 First, the 2015 Nuclear Benchmarking Report does not provide the most recent information. The 2015 report, which is actually based on 2014 information, should not be the basis for setting a stretch factor until 2021, based on information that is now over 2 years old. After the filing of the Application, OPG completed the 2016 Nuclear Benchmarking Report, which it filed on February 10th,' 2017.[579] The 2016 Nuclear Benchmarking Report shows worsening performance. On the same 3-year rolling Total Generating Cost per MWH metric, Darlington drops from the top quartile to the exact median, and Pickering remains in the fourth quartile.[580] Even with this updated information, OPG is not amending its Application.[581] Using OPGs methodology, but updating for the most recent benchmarking information, the stretch factor would be 0.45%.

10.9.9 On a company-wide basis, OPG is in the bottom quartile based on the 2015 Report.[582] It is 12th out of 13 companies benchmarked.[583] Since ratepayers pay one single nuclear payment amount that encompasses the overall costs of both Darlington and Pickering, the stretch factor should be based on the benchmarking results of OPG's nuclear facilities as a whole, not a composite of separate stretch factors for each station. This is the most appropriate way to determine the stretch factor.

10.9.10 Even if it is appropriate to create a weighted stretch factor, by first creating one for each station OPG as has proposed, the production weights should not be historic numbers, but should be based on the forecast production. Using the historic 2015 Board-approved production, or even the updated 2016 actuals, does not account for the changes in relative production of the stations in the test year. In particular, it does not account for reduction in Darlington production due to the DRP. If the Board supports the weighted approach, it should set the annual stretch factor based on the annual

[577] A1-3-2, p.32
[578] *Ibid*
[579] 6.2-SEC-63, Attachment 3
[580] *Ibid*, p.68-69; Tr.6:129
[581] Tr.6:129
[582] 6.2-SEC-63, Attachment 3, p.93; Tr,6:129
[583] *Ibid*

approved 2017-2021 production forecast. This would accurately reflect the changing share of total nuclear production between the two generation stations.

	Darlington & Pickering Weighted Stretch Factors							
	2015BA	**2015A**	**2016A**	**2017F**	**2018F**	**2019F**	**2020F**	**2021F**
Darlington (TWh)	25	23.3	26	19	19.3	19.7	17.7	16.6
Pickering (TWh)	21.6	21.2	20.8	19.1	19.2	19.4	19.6	18.8
Darlington (%)	53.6%	52.4%	55.6%	49.9%	50.1%	50.4%	47.5%	46.9%
Pickering (%)	46.4%	47.6%	44.4%	50.1%	49.9%	49.6%	52.5%	53.1%
Darlington Stretch (2016 BM Report)	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
Pickering Stretch (2016 BM Report)	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
Production Weighted Stretch	0.44%	0.44%	0.43%	0.45%	0.45%	0.45%	0.46%	0.46%
Source: Production Information J15.1								

10.9.11 Applying the stretch factor to only OM&A, and then only a component therein, is not appropriate. The Board expects that any stretch factor should be applied to all major areas of the revenue requirement.

10.9.12 In EB-2016-0116, Toronto Hydro sought to apply its stretch factor only to OM&A, arguing that capital productivity was sufficiently embedded within its plan. The Board disagreed, and required Toronto Hydro to apply its stretch factor to its capital spending plan as well, stating:

> *"The OEB has consistently applied stretch factors to total costs in order to incent productivity in both the areas of capital expenditure and OM&A. The OEB finds no compelling reason to depart from this approach. While the Application put forward by Toronto Hydro may be a custom application, one of the key aspects of the OEB's RRFE is the requirement to continue to make productivity improvements."*[584]

10.9.13 The same rationale applies to OPG: the Board's expectation is that a stretch factor should be comprehensively applied to all aspects of spending, including capital and all sub-components of OM&A.

10.9.14 OPG's position that it will only be able to find efficiency and productivity savings in the base and corporate support OM&A costs is unconvincing.[585] As discussed in greater detail in sections 5.4 and 7.1, there are abilities to create productivity in all aspects of the nuclear OM&A and capital program. OPG's view that a company can only gain efficiency in areas that have "recurring costs" is indicative of its very narrow understanding of productivity. Productivity is not simply doing the same repetitive

[584] *Decision and Order* (EB-2014-0116 – Toronto Hydro-Electric System Limited), December 29 2015, p.18
[585] Argument-in-Chief, p.169

task a little quicker the next time one does it.

10.9.15 Moreover, this issue is not too dissimilar from its hydroelectric payment amounts. OPG has proposed as required a comprehensive incentive regulation regime for its hydroelectric facilities.[586] If approved, it would apply to both capital and OM&A. OPG's hydroelectric capital is also not made up primarily of recurring costs, and its OM&A costs include not just base costs but also project OM&A.[587] If OPG can somehow do it for hydroelectric, it can apply one component of it, a stretch factor, to all aspects of nuclear operations.

10.9.16 If the Board is only going to apply a stretch factor to some aspects of OM&A, then the benchmarking measure used to determine it must be changed to allow for an apples-to-apples comparison. The Total Generating Cost per MWh benchmarks not just operating costs, but also capital costs. If OPG is to be allowed to only apply a stretch factor to OM&A, than the metric that sets that stretch factor should only include OM&A costs. The 2016 Nuclear Benchmarking Report includes two OM&A metrics (2015 3-year fuel operating costs per MWh and 3-year non-fuel operating costs per MWh). [588]

10.9.17 OPG's comments during the hearing that it simply cannot find any more productivity and efficiencies anywhere to increase its stretch factor misses the underlying aspect of Custom IR.[589] It is a form of incentive-ratemaking, as opposed to what OPG is used to, which is cost of service ratemaking. Incentive rate-making is more focused on the benchmarks and less on a utility's own cost structure. The Board described this in EB-2013-0416, the Hydro One Distribution Custom IR decision:

> *"Incentive rate-setting differs from cost of service rate-setting in that it relies less on a utility's internal cost, output, and service quality to establish rates, and more on benchmarks of cost, output, and service quality that are external to the utility revealing superior performance and encouraging best practice. The decoupling of rates from the utility's own costs simulates a competitive market environment and is more compatible with an outcomes based approach to regulation."*[590]

10.9.18 OPG's benchmarking results show that as compared to its peers, has a long way to go.

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[586] A1-3-2
[587] Historically, OPG has categorized its hydroelectric OM&A costs into two categories, base and project OM&A. (See for example EB-2013-0321, F1-1-1, Table 1)
[588] 6.2-SEC-63, Attachment 3, p.74-79
[589] Tr.6:72-73
[590] *Decision with Reasons* (Hydro One Dx - EB-2013-0416), March 12 2015, p.13

10.9.19 The Board should set the nuclear stretch factor of 0.6% applied to all of OPG's nuclear OM&A, including allocated OM&A, and capital (excluding DRP), instead of the proposed 0.3% applied only to a portion of the OM&A.

10.9.20 ***Z-Factor and Materiality Threshold.*** OPG has not specifically proposed a particular mechanism to deal with financial impacts of unforeseen events, but has requested that it that it be able to address them in a way consistent with the RRFE.[591] In Undertaking J8.2, OPG stated that z-factors are just one way that it could be addressed, with the other being an accounting order mechanism similar to the one it has utilized on three separate occasions since its first payment order decision.[592]

10.9.21 SEC does not oppose OPG being eligible for a z-factor to deal with the financial impacts of unforeseen, material, externally driven events. The distinction between a z-factor and accounting order appears to be entirely artificial. The Board has in the past used the z-factor criteria as a test for an accounting order.[593] This makes sense, since an accounting order is simply the creation of a deferral account to deal with the financial impacts on a going-forward basis, where as a z-factor is usually sought when the impact has already occurred (usually due to a one-time event).

10.9.22 SEC does have a concern with OPG's proposed materiality threshold of $10M. While that has been the historic materiality threshold that has been applied by OPG for evidence updates in this proceeding, as well as what was approved in past proceedings, it is no longer appropriate. The Board should adjust OPG's materiality threshold going forward, updating it to reflect the changes in OPG's revenue requirement, since its original payment amounts applications where the $10M amount was originally set[594]. Depending on the methodology it would result in an updated threshold of between $12.1 and $16.8M for nuclear only.[595]

10.10 *Mid-term Review (Issue 11.5)*

10.10.1 OPG is proposing that it be able to adjust its production forecast for the second half of the plan term (July 1st 2019-December 31st 2021) through a mid-term review to take place in the first half of 2019. It proposed that the revenue difference between the approved production forecast in this proceeding, and the adjusted revenue forecast approved in the mid-term review, be captured in a variance account for disposition later.[596] It further proposes to make corresponding adjustments to its fuel costs based on the change in production forecast, which would also be accounted for in a variance account.

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[591] J8.2
[592] *Ibid*
[593] *Decision and Order*, (EB-2014-0311 - Hydro One Networks Inc.), March 27, 2015, p.2-5
[594] We have had a chance to review the submissions of LPMA on this issue, and we agree with their analysis and their calculations.
[595] J8.1
[596] A1-3-3, p.10-14

10.10.2 SEC submits adjusting the production forecast is contrary to the Board's Custom IR expectations. The Board has said in the past that it "expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast."[597] In the Board's *Handbook for Utility Rate Applications* ("Rate Handbook"), which applies to OPG[598], the expectation is that only in exceptional circumstances should there be further rate applications for annual adjustments in Custom IR plans:

> *"Updates: After the rates are set as part of the Custom IR application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral accounts. <u>For example, the OEB does not expect to address annual rate applications</u> for updated cost of capital, working capital allowance or <u>sales volumes.</u> In addition, the establishment of the new deferral or variance accounts should be minimized as part of the Custom IR application." [emphasis added]*[599]

10.10.3 The Rate Handbook specifically references as an example of updates it does not expect to see, absent exceptional circumstances, sales volumes. When asked during the hearing if OPG believed the need to adjust its production forecast, i.e. its sales volumes, was an exceptional circumstance, OPG's witness Mr. Pugh, responded "yes", since the forecasting of five years is "different than anything we've been through.[600]

10.10.4 While forecasting its production for five years is different from what OPG has had to do in applications before, the same could be said for all other utilities whose rates are set by the Board. In fact, the task is much more difficult for natural gas and electricity distributors who are subject to weather and demand variations which are entirely outside of their control. OPG is not affected by either. As a baseload power generator, it will produce, and thus be compensated for all of the power that it can generate. It is not affected by changes in demand. This includes changes in weather which are almost always the primary driver in annual variances in sales volumes from forecast.

10.10.5 SEC therefore submits that OPG's production forecast is not an exceptional circumstance which requires a mid-term adjustment.

10.11 ***<u>Nuclear Rate Smoothing Proposal</u>***

10.11.1 The issue of rate smoothing has devolved into two components:

[597] *Decision with Reasons* (Hydro One Dx - EB-2013-0321), November 20 2014, p.31
[598] *Handbook to Utility Rate Applications*, October 13 2016, p.26
[599] *Ibid*, p.26
[600] Tr.6:189

(a) ***Substantive.*** What is the appropriate smoothing formula to use over the next five years consistent with O.Reg. 53/05, and with good rate-making principles?

(b) ***Procedural***. What is the appropriate point in this process for the Board to consider the options for rate smoothing, and how should that consideration take place to ensure that the Board has full participation by all concerned?

10.11.2 Before looking at the details, it is appropriate to note that OPG's new smoothing proposal actually seeks higher rates at the outset, and on average higher rates over the five year IRM period. This is evidenced by the fact that the deferred revenue is dropping by $400M[601] as OPG has proposed this new rate smoothing method.

10.11.3 So, when OPG said "Our shareholder has been looking at ways to reduce customer bill impacts[602]", that may well have been true, but that is not the result of the new OPG proposal. The new OPG proposal asks the customers to pay more in the 2017-2021 period, not less[603].

10.11.4 What is actually happening is that the new regulation allows, even directs, OPG to seek to hide the size of the nuclear payment amount increases by bundling them with the hydroelectric payment amounts, which will go up much more slowly under Price Cap IRM. OPG's proposal is to increase nuclear payment amounts in 2017 by almost 45%. The WAPA smoothing method allows OPG to present that huge increase as a 2.5% increase in rates.

10.11.5 Having said that, the Board is not in a position to do anything about it, even if it wanted to. OPG has initiated[604] a change in the regulation, to which the Ontario government has agreed. The fact that the result is a much larger initial increase in nuclear payment amounts is not something that is within the Board's control.

10.11.6 Therefore, in the analysis that follows SEC focuses on what the Board can do, in the public interest, while still complying with the full spirit and intent of the revised regulation.

10.11.7 ***The OPG Proposal***. OPG has proposed a rate smoothing mechanism that increases the amounts it bills each customer by 2.5% per year for the five years of this IRM plan[605]. This is intended to include both nuclear and hydroelectric payment amounts and riders, and to be calculated on a production weighted basis using year by year differences.

[601] N3-1-1, p.14
[602] Tr.22:12.
[603] See, e.g. Tr.23:9.
[604] Tr.23:15
[605] N3-1-1, p.2

10.11.8 The OPG proposal is summarized in Table 2 attached to N3-1-1. That table calculates weighted average payment amounts, and the resulting nuclear payment amounts (NPA) to achieve those WAPA figures, as follows[606]:

WAPA Proposal by OPG				
Year	***WAPA***	***% Inc.***	***NPA***	***% Inc.***
2016	$60.97		$59.29	
2017	$62.50	2.51%	$76.39	28.84%
2018	$64.06	2.50%	$78.60	2.89%
2019	$65.66	2.50%	$84.83	7.93%
2020	$67.30	2.50%	$88.21	3.98%
2021	$68.98	2.50%	$92.02	4.32%

10.11.9 For years one of Canada's top philosophy teachers, Professor Howard Adelman (one of the original founders of Rochdale, if anyone remembers that), taught at York University. His basic mantra about understanding the propositions of others was three steps:

(a) What does the author say?
(b) What does the author mean?
(c) What does the author really mean?

10.11.10 His point – absorbed by many thousands of students over the years – was that it is not enough to read the words, or even understand in a nuanced way what they mean. It is also necessary to understand the implications of the propositions being offered. It is only then that you truly understand what is being proposed.

10.11.11 Looked at in that way, the rate smoothing proposal of OPG has implications that it has not been willing to describe to the Board. Those include the following:

(a) In the first two years, while the smoothing may provide limited rate stability in some scenarios for RPP customers, the non-RPP customers, who consume the bulk of the generation from OPG, get a high level of volatility from the OPG proposal.

(b) In the later years of the plan, the rate smoothing proposal would include large rate increases, much larger than under the previous rate smoothing proposal.

10.11.12 SEC has redone Table 2. We have only made two adjustments. First, we have used what would actually happen in 2017 assuming an October 1, 2017 date for new rates, but a January 1, 2017 effective date as proposed by OPG. Second, we have added into the 2019 to 2021 figures nuclear and hydroelectric payment riders at typical levels (in

[606] N3-1-1, Tables 2 and 3, and p.16

this case, the average of the proposed 2017 riders and the actual 2016 riders).

10.11.13 In recasting the table, SEC has calculated the revenue shortfall rate riders over the period to the end of 2019, to reduce the level of volatility that would have arisen had the end of 2018 been used. However, in addition to the shortfall on the payment amounts, we have also included the shortfall on the riders, since that would have to be collected too if a January 1, 2017 effective date is allowed. It would appear to us that the Board is required to include that rider in the WAPA calculation as well.

10.11.14 The point of the revised table, of course, is not to suggest that this is what would actually happen. The point is to demonstrate that, under the OPG proposal as presented to the Board, the real life implications are not rate stability, but rate volatility. If the Board accepts the OPG proposal, it will be undermining rather than achieving the Government's goals in amending O.Reg. 53/05.

10.11.15 Here is the revised table.

Revised OPG Table 2 from N3-1-1

Ln.	Description	2016	Jan/ Sept 2017	Oct/ Dec 2017	2018	2019	2020	2021
1	Hydroelectric Pmt Amt (HPA)	$41.09	$41.09	$41.71	$42.33	$42.97	$43.61	$44.27
	Hydroelectric Pmt Rider (HPR)	$3.46		$1.44	$1.44	$2.45	$2.45	$2.45
	Hydroelectric Rev. Shortfall Rider			$0.69	$0.69	$0.69		
	Total Hydroelectric	$44.55	$41.09	$43.84	$44.46	$46.11	$46.06	$46.72
2	Nuclear Pmt Amt (NPA)	$59.29	$59.29	$76.39	$78.60	$84.83	$88.21	$92.02
	Nuclear Pmt Rider (NPR)	$13.01		$2.85	$2.85	$7.93	$7.93	$7.93
	Nuclear Rev. Shortfall Rider			$6.55	$6.55	$6.55		
	Total Nuclear	$72.30	$59.29	$85.79	$88.00	$99.31	$96.14	$99.95
3	Hydroelectric Prod. Forecast (HPF)	33.0	24.8	8.3	33.0	33.0	33.0	33.0
4	Nuclear Production Forecast (NPF)	47.8	28.6	9.5	38.5	39.0	37.4	35.4
5	Total Production	80.8	53.3	17.8	71.5	72.0	70.4	68.4
6	Hydroelectric Portion of WAPA	$18.19	$19.07	$20.35	$20.52	$21.13	$21.59	$22.54
7	Nuclear Portion of WAPA	$42.77	$31.77	$45.97	$47.38	$53.79	$51.07	$51.73
8	WAPA	$60.97	$50.84	$66.32	$67.90	$74.93	$72.67	$74.27
9	% change in Hydroelectric		-7.77%	6.68%	1.41%	3.71%	-0.10%	1.43%
10	% change in Nuclear		-17.99%	44.70%	2.58%	12.85%	-3.19%	3.96%
11	% change in WAPA		-16.61%	30.44%	2.39%	10.34%	-3.02%	2.21%
12	Annual % increase			8.78%	2.39%	10.34%	-3.02%	2.21%
13	Hydroelectric PA Shortfall		$15.3					
14	Hydroelectric Rider Shortfall		$35.6					
15	Total Hydroelectric Shortfall ($M)		$51.0					
16	Shortfall Rider - Hydroelectric ($/MWh)		$0.69					
17	Nuclear PA Shortfall		$488.6					
18	Nuclear Rider Shortfall		$81.4					
19	Total Nuclear Shortfall ($M)		$570.1					
20	Shortfall Rider - Nuclear ($/MWh)		$6.55					

10.11.16 The results in this table are consistent with the evidence of OPG, under cross-examination in the oral hearing.

10.11.17 ***What Happens in 2017?*** OPG presented a proposal to the Board that it said produced smoothed rates in 2017 and beyond, preventing volatility. Under cross-examination, OPG admitted that was actually misleading[607]. It is only with respect to RPP customers that volatility is reduced. With respect to non-RPP customers, who are the largest consumers of OPG's generation, volatility is not addressed by the OPG proposal.

10.11.18 For Ontario's schools, for example, they have so far in 2017 experienced a drop of 16.61% in their per MWh costs from OPG, which works out to about $900,000 per month. On October 1, 2017, assuming OPG's proposal, they will experience an increase of 30.44%, i.e. an incremental $1,400,000 per month, just in time for their new budget year[608], but after their new budgets have been finalized by the Province.

10.11.19 The same impact will be felt in most industrial, commercial and institutional enterprises around the province. It is the worst kind of volatility. Drop rates for a short time, then come back full force with a massive increase[609].

10.11.20 OPG's response to that was to come back time and again to the RPP customer, who would not see the up and down because of the lagged reset of RPP rates every six months[610].

10.11.21 SEC notes that it is not only obviously contrary to the public interest to ignore the impacts on the customers who buy the bulk of your generation. It is also just as obviously contrary to law for OPG, or the Board for that matter, to consider only residential impacts and not the impacts on other customer classes. Rates set on that basis would not be "just and reasonable".

10.11.22 SEC believes that the volatility in 2017 is clear, and in keeping with the spirit and intent of the new regulation, the Board should seek to minimize that volatility to the extent that it can. We make a proposal below that would go some of the way towards achieving that result.

10.11.23 ***And What About 2019-2021?*** OPG asks the Board to smooth rates for the full five year period, with rate riders included in the calculation for 2016, 2017 and 2018, but with any rate riders ultimately approved in a subsequent proceeding for 2019-2021 treated as extra, on top of the smoothed rates.

10.11.24 SEC submits that this is inconsistent with the evidence, contrary to good rate-making principles, and contrary to the revised regulation.

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[607] Tr.23:17
[608] That will go up a further $200,000 per month in 2018, and $600,000 per month in 2019, then decline slightly in 2020 and jump up again in 2021. That is all assuming that the DRP does not go materially over budget.
[609] This is discussed in the proceeding as if it only affects OPG. Volatility like that proposed by OPG has real world impacts. People get laid off. Businesses fail. This is not a small impact that can be buried by the Fair Hydro plan. The consequences will be real.
[610] E.g. Tr.23:22, but there are a number of other examples.

10.11.25 The evidence is clear that there will almost certainly be rate riders for both hydroelectric and nuclear in 2019-2021. OPG admits as much[611], and admits that the riders in 2019 could be large. This is especially true given the obvious risk of cost overruns in the DRP, which could be reflected in the CRVA. In fact, since OPG became regulated it has always had rate riders, except, as in 2017, where existing riders have expired and their new riders have not yet kicked in.

10.11.26 Thus, the evidence before the Board is that there will almost certainly be additional charges to ratepayers in 2019 which have not been included in the OPG forecasts[612]. The average since regulation has been $4.33/MWh[613].

10.11.27 SEC submits that failure to include high probability amounts in the forecast because they are not known for sure results in smoothing that is already known to be incorrect, and likely materially so. It is not the Board's practice, and not good rate-making policy, to use forecast amounts – in this case, zero - that will almost certainly be wrong.

10.11.28 Perhaps recognizing that, OPG says that the riders that are not approved in this proceeding should simply be treated as outside of the rate smoothing process.

10.11.29 SEC submits that such an approach is contrary to the regulation.

10.11.30 The last is the easiest point. O.Reg.53/05 directs the Board to determine the revenue requirements for OPG for the five years 2017-2021, and the amount of that revenue requirement that will be deferred for smoothing purposes. Nothing in the regulation requires the Board to fix the dollar amounts for deferral in advance of the five year period. The Board is directed to make a determination, and the sole direction that the Board must make that determination "*with a view to making more stable the year-over-year changes in the OPG weighted average payment amount over each calculation period*"[614].

10.11.31 The term "weighted average payment amount" ("WAAP") is a defined term, and it expressly includes nuclear and hydroelectric payment riders. The Board is therefore required by law to consider riders in its smoothing calculation, and is required to seek stability, not just in base payment amounts, but in payment amounts including riders. There is no option here. The regulation is prescriptive in nature.

10.11.32 SEC therefore submits that the Board cannot, and should not, accept the OPG proposal to treat riders, other than those approved in this proceeding, as "extra". The

[611] Tr.23:23
[612] In fairness, they can't include them, because they can't forecast an amount that is inherently about variances from forecasts.
[613] SEC's calculation, which OPG accepted. Tr.23:23
[614] O.Reg.53/05, s. 6(12)(i)

Board should either:

(a) Establish a rate smoothing formula and process that, while fully compliant with the regulation, self-adjusts when the amounts of future rate riders are known (the "formula approach"); or

(b) Make reasonable assumptions about riders for 2019-2021, and build those into the forecasts on which the rate smoothing mechanism is built in compliance with the regulation (the "forecast approach").

10.11.33 ***SEC Rate Smoothing Proposal.*** SEC proposes that the Board use the formula approach to compliance with the regulation. To provide some visibility, however, SEC proposes that the Board establish a forecast at the outset, which would be used to start the rate smoothing proposal off, and also test its appropriateness in the later years. The formula would then adjust those payment amounts, when actual rate riders in 2019-2021 are known, based on the principles outlined in the formula.

10.11.34 The specifics of the SEC proposal are as follows:

(a) The proposal of OPG to target 2.5% per year increases in weighted average payment amounts should be accepted and implemented.

(b) Because of the high volatility that would already exist in 2017, the WAPA increase in 2017 should be limited to zero. Based on the Application, this would still result in an increase in the nuclear payment amount in 2017 of almost 28%, but it would ameliorate the roller coaster that non-RPP customers would otherwise experience this year.

(c) The WAPA calculation is solely adjusted through the nuclear payment amount. In any year where, because of changes to the riders, the result would be that the nuclear payment amount would go down, the default would be to leave it at the same level. If the 2.5% target could not be accomplished by adjustments to the rate riders, an increase in WAPA greater than 2.5% would be allowed.

10.11.35 SEC has modeled the impacts of its proposal using the unamended revenue requirements and other proposals in the OPG Application. The result is in the following table:

Revised OPG Table 2 from N3-1-1 - SEC Proposal

Ln.	Description	2016	Jan to Sept, 2017	Oct to Dec., 2017	2018	2019	2020	2021
1	Hydroelectric Pmt Amt (HPA)	$41.09	$41.09	$41.71	$42.33	$42.97	$43.61	$44.27
	Hydroelectric Pmt Rider (HPR)	$3.46		$1.44	$1.44	$2.45	$2.45	$2.45
	Hydroelectric Rev. Shortfall Rider			$0.69	$0.69	$0.69		
	Total Hydroelectric	$44.55	$41.09	$43.84	$44.46	$46.11	$46.06	$46.72
2	Nuclear Pmt Amt (NPA)	$59.29	$59.29	$68.87	$71.01	$71.01	$78.97	$82.71
	Nuclear Pmt Rider (NPR)	$13.01		$2.85	$2.85	$7.93	$7.93	$7.93
	Nuclear Rev. Shortfall Rider			$4.08	$4.08	$4.08		
	Total Nuclear	$72.30	$59.29	$75.80	$77.94	$83.02	$86.90	$90.64
3	Hydroelectric Prod. Forecast (HPF)	33.0	24.8	8.3	33.0	33.0	33.0	33.0
4	Nuclear Production Forecast (NPF)	47.8	28.6	9.5	38.5	39.0	37.4	35.4
5	Total Production	80.8	53.3	17.8	71.5	72.0	70.4	68.4
6	Hydroelectric Portion of WAPA	$18.19	$19.07	$20.35	$20.52	$21.13	$21.59	$22.54
7	Nuclear Portion of WAPA	$42.77	$31.77	$40.62	$41.97	$44.97	$46.17	$46.91
8	WAPA	$60.97	$50.84	$60.97	$62.49	$66.10	$67.76	$69.45
9	% change in Hydroelectric		-7.77%	6.68%	1.41%	3.71%	-0.10%	1.43%
10	% change in Nuclear		-17.99%	27.85%	2.82%	6.52%	4.67%	4.30%
11	% change in WAPA		-16.61%	19.91%	2.50%	5.79%	2.50%	2.50%
12	Annual % increase			0.00%	2.50%	5.79%	2.50%	2.50%
13	Hydroelectric PA Shortfall		$15.3					
14	Hydroelectric Rider Shortfall		$35.6					
15	Total Hydroelectric Shortfall ($M)		$51.0					
16	Shortfall Rider - Hydroelectric ($/MWh)		$0.69					
17	Nuclear PA Shortfall		$273.7					
18	Nuclear Rider Shortfall		$81.4					
19	Total Nuclear Shortfall ($M)		$355.2					
20	Shortfall Rider - Nuclear ($/MWh)		$4.08					

10.11.36 The effect of this proposal would be to increase the amount of deferred revenue from $1.0 billion, as proposed by OPG, to just under $2.4 billion, almost a billion more than the original OPG proposal**.** SEC believes that this would result in unacceptable credit metrics. The 2.5% target would have to be adjusted upward to 3.5% per year, and including 2017. Once that was done, even on the OPG proposed spending plan, unamended, the deferred revenue would be very close (within $70 million) to the amount in the original OPG proposal, which OPG said was acceptable.

10.11.37 Of course, it is unlikely that the Board will approve the OPG Application without any adjustments to revenue requirement or rates. We have therefore modelled the SEC proposal on the assumption that the Board orders an effective date after the payment amounts order, and adopts the proposals of OEB Staff with respect to adjustments to revenue requirement and rates. Those proposals would give OPG higher revenues and rates than SEC and a number of other customer representatives are proposing, but lower than OPG has requested.

10.11.38 Modeled with those adjustments, the amount of deferred revenue over the entire five year period is reduced to $465M, well below the threshold that would put pressure on OPG credit metrics.

10.11.39 ***Conclusion***. SEC therefore submits that the Board should establish a smoothing mechanism, as required by O.Reg.53.05, that targets a zero increase in WAPA when the new rates are implemented, and 2.5% per year in each of the remaining years, but with a higher increase where otherwise the nuclear payment amount would have to go down. The smoothing amounts should be forecast now, including all known rate riders (including riders to recover any revenue shortfall) and forecasts of future rate riders, and should be adjusted in accordance with the formula when there are any changes to the nuclear or hydroelectric payment riders.

10.11.40 ***Procedure Going Forward***. OPG and OEB Staff have both suggested that the rate smoothing mechanism should be finalized during the payment order process, when the revenue requirement, unadjusted rates, riders, and other decisions of the Board are known. SEC agrees that this is a sensible proposal.

10.11.41 However, SEC is concerned that the ability during the payment amounts order process to get full discovery, and for customer groups to participate, could be constrained either by time or by process assumptions. SEC urges the Board to ensure that, on this important aspect - the actual setting of the rates customers will pay - parties are given a full opportunity to participate.

10.12 ***Off-Ramp***

No submissions.

11 OTHER MATTERS

11.1 ***Effective Date (Issue 12.1)***

11.1.1 **Determination of Effective Date.** OPG filed this Application on May 27, 2016, but is seeking a January 1, 2017 effective date. SEC submits that allowing for 218 days to complete this process was unreasonable, and the Board should not allow the January 1, 2017 effective date.

11.1.2 This Application is the biggest and most complex rate application for any utility in Canadian history. Not only does it involve more than $27 billion of proposed revenue requirement, but it also contemplates the review of a large and risky nuclear capital plan. It is a five-year Custom IR application for nuclear, the first time that has ever happened in Canada, and a five year Price Cap IRM application for hydroelectric, also the first time that has ever happened. In addition to the obvious, there are many other twists and turns that the Board must address.

11.1.3 OPG is a large and experienced utility. This is not their first rodeo. It should have been – and undoubtedly was - readily apparent to them that a period of less than nine months would be woefully inadequate to deal with this Application. The time frame for EB-2013-0321 was 447 days from filing to payment amounts order. The time frame for EB-2010-0008 was 321 days from filing to payment amounts order. The time frame for EB-2007-0905 was 367 days from filing to payment amounts order. All of those were less complex applications, with less money involved and fewer major issues to address.

11.1.4 Not only that, but OPG was warned in the last proceeding that it could not simply delay its filing at its own convenience, then expect to recover a deficiency for the intervening period. On the principles at play in determining effective date, the Board had this to say[615]:

> *"The Board has determined that the effective date for the payment amounts for the nuclear and previously regulated hydroelectric facilities will be November 1, 2014. The Board is not prepared to accept the January 1, 2014 effective date proposed by OPG as it is contrary to the Board's long-standing practice of setting rates on a forecast (i.e. forward test year) basis.*
>
> ***The Board's general practice with respect to the effective date of its orders is that the final rate becomes effective at the conclusion of the proceeding.*** *This practice is predicated on a forecast test year which establishes rates going forward, not retrospectively. Going forward, the utility knows how much money it has available to spend and the*

[615] *Decision with Reasons* (EB-2013-0321 - OPG 2014-2015), p.134-5.

> *ratepayer knows how much it is going to cost to use electricity in order to make consumption decisions. The forecast test year enables both the utility and the ratepayer to make informed decisions based on approved rates. The forecast test year is a pillar in rate setting and **the Board's practice must be respected.***
>
> *The Board must control its regulatory process. The Board hears a large number of cases throughout the year and must plan its resources accordingly to ensure cases are completed and decisions are rendered. In cases where utilities have not filed their applications in time to have rates in place prior to the effective date, the Board's practice has typically been to not allow the utility to retrospectively recover the amounts from the period where the interim order was in effect. All applicants are aware of the Board's metrics. The process for an oral hearing is expected to take 235 days from the filing of the application to the issuance of the final decision, and 280 days until the issuance of the rate order." [emphasis added]*

11.1.5 Further, while there are metrics, the Board has always made clear to regulated utilities that it is their responsibility, not that of the Board, to engage the regulatory process with sufficient time to achieve the results the utility is proposing.

11.1.6 Enbridge and Union Gas get it. While they are aware of the 280 day metric for applications, they will be filing their January 1, 2019 rate applications in November of 2017, giving themselves fourteen months lead time. That is, of course, now included in their filing requirements, but the Board is well aware that they already in any case planned to file that early to ensure a timely result. Those are both expected to be much simpler applications than this one.

11.1.7 OPG, on the other hand, appears not to have listened when the Board told it to get on top of the timing of its regulatory process. It appears to disagree with the Board that "the Board's practice must be respected".

11.1.8 SEC is aware that OEB Staff proposes to give OPG a free pass in this case. SEC disagrees. If the Board can't expect the largest regulated utility in the province to respect its practices, and to be responsible in the timing of its applications, it can hardly expect the smaller utilities to do so.

11.1.9 SEC therefore submits that the effective date for the payments order in this proceeding should be the beginning of the month following the payment amounts order. It is our estimate that will be October 1, 2017, 461 days after the Application was filed. While this is longer than the Board's normal 280 day window, this is not a normal application. Further, it is in the same range as EB-2013-0321, which took 447 days, and generated the Board's comments on effective date and the utility's regulatory responsibility, quoted above.

11.1.10 ***Clawback Issue***. Stung by the result in EB-2013-0321, where despite the Board's determination on effective date, OPG subsequently recovered much of the intervening deficiency through deferral and variance accounts in EB-2014-0370, SEC in cross-examination of OPG witnesses in this proceeding asked whether a later effective date would mean OPG actually loses anything.

11.1.11 OPG's response was in Undertaking J23.1. In that undertaking, OPG claims that it would use the RSVA to claw back the entire amount of the deficiency for the period from January 1, 2017 to the effective date ordered by the Board.

11.1.12 SEC is not surprised, but does submit that the Board should refuse to allow this perversion of the plain meaning of O.Reg.53/05 and the RSVA concept. In no way is O.Reg. 53/05 designed or intended to take away from the Board its statutory right to control its process, including its right to determine the effective date of new payment amounts.

11.1.13 We note that this is not the first time OPG has argued for limitations on the Board's control of this aspect of its mandate. In EB-2013-0321, OPG made the shocking argument that, once the Board makes rates interim, it cannot choose an effective date later than the date of interim rates, because then they would not be just and reasonable. The Board obviously rejected that argument in its decision.

11.1.14 In this case, OPG claims that if the Board determines a revenue requirement for calendar 2017, then under O.Reg.53/05 OPG is entitled to collect that entire revenue requirement, no matter what the Board says about effective date.

11.1.15 SEC submits that the Board has an easy solution to this absurd technical argument. The Board should, in our submission, determine that the revenue requirement for the period from January 1, 2017 to the effective date of new payment amounts is the actual volumes for hydroelectric and nuclear for that period, multiplied by the existing payment amounts approved in EB-2013-0321 and in effect during that period. It should then determine that the revenue requirement for the period from the effective date until December 31, 2017 is the pro rata calculation of the calendar revenue requirement that otherwise would have been determined.

11.1.16 By way of example, if the effective date ends up being October 1, 2017, the actual nuclear production for January 1, 2017 to September 30, 2017 is 28.6 Twh[616], and the annualized 2017 revenue requirement for nuclear, after Board adjustments, would have been $3,000M[617], the Board would determine the 2017 nuclear revenue requirement for ratemaking purposes as follows:

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[616] 75% of the current 2017 12 month forecast.
[617] OPG has applied for $3,161M for 2017, and for the purposes of the hypothetical we are assuming some reductions by the Board in its Decision.

(a) For the period January 1, 2017 to September 31, 2017, the volume of 28.6 TWh. times the approved nuclear payment amount, $59.29, for a total of $1,695.7M.

(b) For the period October 1, 2017 to December 31, 2017, the annualized revenue requirement of $3,000M, multiplied by 92 days in October through December, and divided by 365, for a total of $756.2M.

(c) For the calendar year 2017, the revenue requirement, including the figure to be used for RSVA purposes, is the sum of the two, being $2,451.9M.

11.1.17 SEC notes that, whatever the Board does to protect its process and avoid this RSVA clawback trick, it is likely that some of the effective date reduction will still be clawed back by OPG through other deferral and variance accounts. As the Board saw in EB-2014-0370, even with the best of intentions the regulator has only limited ability to hold OPG to account, given the strong protection it has from government-mandated deferral and variance accounts.

11.1.18 SEC therefore submits that the Board should take proactive steps to ensure that its decision on effective date is not subverted by an inappropriate use of the RSVA, but should recognize that even with those steps the cost to OPG of an effective date later than January 1, 2017 is likely to be only a fraction of what it first appears to the Board.

11.2 ***Costs***

11.2.1 The School Energy Coalition hereby requests that the Board order payment of our reasonably incurred costs in connection with our participation in this proceeding. It is submitted that the School Energy Coalition has participated responsibly in all aspects of the process, in a manner designed to assist the Board as efficiently as possible

All of which is respectfully submitted.

Original signed by

Jay Shepherd & Mark Rubenstein
Counsel for the School Energy Coalition

12 APPENDICES

APPENDIX A

SEC Revised JT 3.2

Group	Segment	WTW Estimate: TDC Costs Above (Below) 50thP ($M)	SEC Estimate: TDC Cost Difference P50 for Entire Org (1)	SEC Estimate: TDC Cost Difference P50 inc P50 for Nuc Auth for Entire Org (2)	OPG Headcount (Apr 1 2015): Nuclear Org	OPG Headcount (Apr 1 2015): Corporate Groups	OPG Headcount (Apr 1 2015)	% Nuclear Regulated (from Appendix 2K Data): Nuclear Org	% Nuclear Regulated (from Appendix 2K Data): Corp Groups	% of Headcount	OPG Estimate of Nuclear Regulated Costs	SEC Estimate of Nuclear Regulated Costs	SEC Estimate of Nuclear Regulated Costs (All P50)
		A	A2	A3	B	C	D	E	F	G = (B x E + C x F) / D	H = A x G	i = A2 x G	J = A3 x G
Mgmt	Utility	-13.8	-20.7	-20.7	358	81	532	99%	71%	77%	-10.7	-16.0	-16.0
	Nuclear Authorized	-4	-4.2	-3.1	33	6	39	100%	100%	100%	-4.0	-4.2	-3.1
	General Industry	0.6	0.8	0.8	94	386	491	99%	71%	75%	0.4	0.6	0.6
	Mgmt Sub-Total	-17.1	-24.1	-23.0	485	473	1,062	99%	71%	77%	-14.2	**-19.6**	**-17.7**
Society	Utility	13.4	16.6	16.6	1,630	302	2,235	100%	75%	83%	11.1	13.8	13.8
	Nuclear Authorized	-1.9	-4.0	-1.8	77	34	111	100%	100%	100%	-1.9	-4.0	-1.8
	General Industry	7.4	14.6	14.6	118	429	572	100%	75%	77%	5.7	11.2	11.2
	Society Sub-Total	18.9	27.2	29.4	1,825	765	2,918	100%	75%	82%	14.9	**21.0**	**23.2**
D\A/I 1	Utility	14.1	16.7	16.7	2,711	191	3,754	100%	90%	77%	10.8	12.8	12.8
	Nuclear Authorized	3.9	3.9	7.7	255	0	255	100%	100%	100%	3.9	3.9	7.7
	General Industry	17.6	25.5	25.5	621	680	1,524	100%	90%	81%	14.2	20.6	20.6
	PWU Sub-Total	35.6	46.1	49.9	3,587	871	5,533	100%	90%	79%	29.0	**37.4**	**41.1**
Total		37.4	49.2	56.3	5,897	2,109	9,513				**29.7**	**38.8**	**46.7**

Determination of Regulated Portion Based on Organizational Details *(Prorated costs provided by WTW to each organization, and then used 2K FTE proportions to identify that which is assocaited with Regulated Nuclear, including both Direct (Nuclear Org) & Allocated (Corp Group) costs.*

Source:
(1) See Calculation Sheet column E
(2) See Calculation Sheet column G

Calculation Sheet

OPG Group (a)	Total # OPG Incumbents (b)	Total # OPG Incumbents Benchmarked (c)	WTW Estimate - TDC Costs at P50 ($M) (d)	TDC Cost at P5O Entire Org (e)	TDC Cost at P50 - Nuc Auth at P50 ($M) (f)	TDC Cost at P50 Entire Org - Nuc Auth at P50 ($M) (g)
				b/c*e		b/c'*f
Management Group						
Utility	532	355	-13.8	-20.7	-13.8	-20.7
Nuclear Authorized	39	37	-4	-4.2	-3.0	-3.1
General Industry	491	362	0.6	0.8	0.6	0.8
Management Subtotal	**1062**	**754**	**-17.2**	**-24.1**	**-16.16**	**-23.0**
Society Group						
Utility	2235	1808	13.4	16.6	13.4	16.6
Nuclear Authorized	111	53	-1.9	-4.0	-0.8	-1.8
General Industry	572	290	7.4	14.6	7.4	14.6
Society Subtotal	**2918**	**2151**	**18.9**	**27.2**	**19.952**	**29.4**
PWU Group						
Utility	3754	3169	14.1	16.7	14.1	16.7
Nuclear Authorized	255	255	3.9	3.9	7.7	7.7
General	1524	1051	17.6	25.5	17.6	25.5
PWU Subtotal	**5533**	**4475**	**35.6**	**46.1**	**39.35**	**49.9**
TOAL	9513	7380	**37.3**	**49.2**	**43.1**	**56.3**

Source: (b)& (c) F4-3-1, Attach 2, p.3; (d) JT3.2, Attach 1, column A

Nuclear Authorized (P50)

Category	# OPG Matched Positions	TDC OPG. Avg.n ($K)	TDC P50 ($K)	Difference ($K)	Diff x OPG Matched Positions ($K)
Management*	37	287	367	-80	-2,960.00
SEP	53	213	229	-16	-848.00
PWU	255	167	137	30	7,650.00

Source: F4-3-1, Attach 2, p.18-20

* Management has 37 positions listed, but for one position the information is not disclosed due to small sample size in that sub-category. For the purposes of this calculation SEC has assumed the 37th person has the same difference from the other positions in the category.

Nuclear Liabilities Summary GAAP vs. ONFA (After Tax Impacts)

#	Description	Units	Reference	2017	2018	2019	2020	2021	Total
	GAAP Amounts								
1	Depreciation of Asset Retirement Costs	Prescribed	N1-1-1, Table 2, Line 1	77.3	77.3	77.3	77.3	7.9	317.1
2		Bruce	N1-1-1, Table 2, Line 9	68.6	68.6	68.6	68.4	68.4	342.6
3		Total		**145.9**	**145.9**	**145.9**	**145.7**	**76.3**	**659.7**
4	Used Fuel Storage Variable Expense	Prescribed	N1-1-1, Table 2, Line 2 less J20.8, Chart 1, Line 2	36.4	38.4	48.9	38.6	42.6	204.9
5		Bruce	J21.2, Table 1, Line 16	57.0	55.0	59.3	64.2	52.2	287.7
6		Total		**93.4**	**93.4**	**108.2**	**102.8**	**94.8**	**492.6**
7	Low and Int. Level Waste Mgmt. Exp.	Prescribed	N1-1-1, Table 2, Line 3	12.5	10.1	12.2	14.0	15.9	64.7
8		Bruce	J21.2, Table 1, Line 17	2.5	3.0	2.8	3.4	4.6	16.3
9		Total		**15.0**	**13.1**	**15.0**	**17.4**	**20.5**	**81.0**
10	Accretion and Earnings	Prescribed	N1-1-1, Table 2, Line 1	25.9	22.1	18.3	14.5	12.4	93.2
11		Bruce - Accretion	J21.2, Table 1, Line 14	458.6	465.7	480.6	495.8	512.4	2413.1
12		Bruce - Earnings	J21.2, Table 1, Line 15	393.0	404.3	415.6	426.2	436.0	2075.1
13		Bruce - Net	Line 11 minus Line 12	65.6	61.4	65.0	69.6	76.4	338.0
14		Total		**91.5**	**83.5**	**83.3**	**84.1**	**88.8**	**431.2**
15	Total Accrual Amounts (Pre-Tax)	Prescribed	Compare: J21.2, Chart 1, Line 1	152.1	147.9	156.7	144.4	78.8	679.9
16		Bruce	Compare: J21.2, Chart 1, Line 8	193.7	188.0	195.7	205.6	201.6	984.6
17		Total		**345.8**	**335.9**	**352.4**	**350.0**	**280.4**	**1664.5**
18	Tax Impacts	Prescribed	J21.2, Table 1, Line 2+4	-27.9	-32.3	-19.5	-30.0	-49.0	-158.7
19		Bruce	Offsets: See J21.2, Table 1	0.0	0.0	0.0	0.0	0.0	0.0
20		Total		**-27.9**	**-32.3**	**-19.5**	**-30.0**	**-49.0**	**-158.7**
21	Total Accrual Amounts (After tax)	Prescribed	Compare: J21.2, Chart 1, Line 5	124.2	115.6	137.2	114.4	29.8	521.2
22		Bruce	Compare: J21.2, Chart 1, Line 8	193.7	188.0	195.7	205.6	201.6	984.6
23		Total		**317.9**	**303.6**	**332.9**	**320.0**	**231.4**	**1505.8**
	ONFA Amounts								
24	Actual Expenditures	Prescribed	N1-1-1, Table 3, Line 8	217.5	227.9	232.8	283.6	317.0	1278.8
25		Bruce	N1-1-1, Table 4, Line 8	157.0	164.2	198.6	201.0	215.7	936.5
26		Total		**374.5**	**392.1**	**431.4**	**484.6**	**532.7**	**2215.3**
27	Contributions to Seg Funds	Prescribed	J20.8, Chart 1, Line 4	102.5	102.5	102.5	102.5	102.5	512.5
28		Bruce	J20.8, Chart 1, Line 12	-102.5	-102.5	-102.5	-102.5	-102.5	-512.5
29		Total		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
30	Recoveries from Seg Funds	Prescribed	N1-1-1, Table 3, Line 15	84.4	85.7	120.4	152.0	193.7	636.2
31		Bruce	N1-1-1, Table 4, Line 15	70.5	70.9	93.7	119.7	144.3	499.1
32		Total		**154.9**	**156.6**	**214.1**	**271.7**	**338.0**	**1135.3**
33	Net Cash Amounts	Prescribed	Compare: J21.2, Table 1, Line 6	235.6	244.7	214.9	234.1	225.8	1155.1
34		Bruce	Compare: J21.2, Table 1, Line 14	-16.0	-9.2	2.4	-21.2	-31.1	-75.1
35		Total		**219.6**	**235.5**	**217.3**	**212.9**	**194.7**	**1080.0**
36	**GAAP Less ONFA - Difference**	Prescribed	Compare: J20.8, Chart 1, Line 7 plus J21.2, Chart 1, Line 2+4	-111.4	-129.1	-77.7	-119.7	-196.0	-633.9
37		Bruce	Compare: J21.2, Table 1, Line 8 less J20.8, Chart 1, Line 14	209.7	197.2	193.3	226.8	232.7	1059.7
38		Total		**98.3**	**68.1**	**115.6**	**107.1**	**36.7**	**425.8**