EB-2016-0152

Before the Ontario Energy Board

Ontario Power Generation Inc.
Application for payment amounts
January 1, 2017 to December 31, 2021

Final Argument of the Green Energy Coalition

Contents

The GEC's submissions address three topics and related issues: Pickering Continued Operations, the Darlington Refurbishment Program, and Rate Smoothing.

1. Issues 6.1, 6.3, 6.5 – Nuclear OM&A, Fuels and Pickering Extended Operations

GEC submits that the extended operation of Pickering is not cost effective. While our submissions focus on that issue (issue 6.5), a determination on that issue will impact OM&A and Fuels (Issues 6.1 and 6.3), depreciation (Issue 6.9) nuclear liabilities (Issue 8), as well as compliance with Reg. 53/05 (Issue 4.1).

OPG proposes to run its aging Pickering Nuclear Station for up to six years beyond 2018 (the point at which transmission constraints necessitating its operation will have eased). Pickering is a dangerous and expensive station on the edge of a city of 3 million. It would not meet the safety requirements for new reactors. Due to its small reactor size and age, it is among the least cost-effective nuclear stations on the continent.[1]

As discussed below, operation beyond 2018 is both unnecessary and uneconomic compared to alternatives. It is not needed to meet load or carbon reduction objectives. In short, Pickering is well past its best before date. Its extended operations will cost ratepayers dearly. Even the conservative planers at the IESO are not prepared to say it is needed, only that is "an option worth continuing to explore".[2] If ever there was a time for the Board to step up and protect ratepayers, now is the time.

a) The Board's Jurisdiction and its obligation to address the appropriateness of the PEO

On December 9th in the context of motions for further and better interrogatory responses, Board Staff offered submissions on the scope of the OEB's jurisdiction and the appropriate scope of review of Pickering Extended Operations (PEO). Staff correctly noted:

- Section 78.1 sets the standard for payments as "just and reasonable"
- Section 78.1(6) provides that the burden rests with the applicant

[1] Exhibit L, Tab 6.2 Schedule 15 SEC-063 Attachment 3 Page 6 of 107.
[2] K.12.1, p. 41

- The Divisional Court in the Toronto Hydro-Electric System case emphasized the Board's broad powers
- "If the OEB determines that a proposed project provides poor value for ratepayers, then it should not approve costs associated with that project."
- Extending Pickering is not in the current LTEP
- The Government has the power to direct the Board in regard to need for specific projects. It has done so in regard to the DRP but has not done so in regard to Pickering. The doctrine of implied exclusion suggests that the absence of a directive is intentional and therefore the Board's ordinary powers and scope of review should apply.

OPG points out that the Government has indicated support for the project in a January 2016 press release. However, the Government has **subsequently** clarified in the House, on October 26th 2016, that it has only given approval for OPG to "**pursue approvals"** before the CNSC and the OEB and then ***"to return to the government after we have all the information."*** At which point the minister and cabinet will make a "*final decision*"[3] OPG argues that a decision has been made implying that it is final. This is tantamount to suggesting that the Deputy speaking on behalf of the Minister and the government has misled the House. The Board cannot accept such a suggestion. The statements in Hansard are unambiguous – the government awaits "*all the information*".

While the Board is not the system planner, the Board is relied upon by government to be an expert body on the economic aspects of energy regulation. It may be that a project that is not cost-effective is nevertheless warranted for other system planning objectives, but that is for the government to determine with the advice of the Board on economics, the CNSC on safety, and the IESO on technical planning aspects. As evident from the exchange in Hansard, the government awaits the Board's consideration of the matters within its area of expertise. If the Board finds PEO non-cost-effective and limits payments accordingly, and the government nevertheless finds it advisable to run Pickering, it can simply direct the IESO to procure the power and the funds would flow via the general adjustment. Alternatively, the Board can determine appropriate payments with and without extended operations, set rates on an interim basis and finalize rates after the government determines the need question in light of "all the information".

Accordingly, in GEC's submission, the Board has both the power and the obligation to review the cost-effectiveness of Pickering extended operations and to provide the government with its findings. Thus, OPG has the burden of demonstrating cost effectiveness. As discussed below, OPG has not met that burden.

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[3] K12.1, p. 5 & 7 (Hansard 26 October 2016 at pp. 69 & 71)

b) Pickering extension beyond 2018 (PEO)[4] is not cost-effective

OPG has elected to file studies from two years ago and not to update them. In GEC's submission the reason that OPG has not updated these studies is clear – to do so would make clear that PEO will cost ratepayers hundreds of millions of dollars. As can be seen by the sensitivity analyses in the various vintages of studies that are before the Board, lower gas costs, lower carbon costs, and lower load forecasts all reduce the cost-effectiveness of the proposal. The evidence before the Board, which is discussed below, makes clear that each of these critical variables has in fact moved in that direction and that the project is highly likely to impose significant cost on ratepayers. The Board should also note the submissions of Environmental Defence on current forecasts of production, operating costs and peak availability, all of which are worse than modeled in 2015. OPG's failure to provide updated analysis in light of these trends must lead to a conclusion that OPG has not met the burden of proof that the Act explicitly imposes on the corporation.

OPG filed evidence produced by OPG and by the IESO on the cost/benefit of PEO and the Board heard extensive cross-examination thereon. However, in its Decision on motion day the Board indicated that it would not require IESO or OPG to update the economic analyses of PEO despite *prima facie* evidence that there has been a significant shift in the inputs to those analyses. If that determination rests on the premise that the applicant bears the burden and controls its case, so be it. In that case GEC submits that OPG has simply failed to make its case. Alternatively, if the Board were to base a decision to allow Pickering costs into rates based on clearly outdated information and analyses GEC submits that the Board will have inappropriately curtailed its scope of review, and turned a blind eye to the facts and the welfare of ratepayers. We trust that is not the situation.

c) The lower load forecast alone has wiped out any possible PEO system economic benefit

The 2015 OPG and IESO studies fail to include a sensitivity analysis for lower load forecast. However, a sensitivity to load forecast is provided in the earlier IESO studies filed in the previous case and included in K 12.1 at p. 28 and 31. The 2012 study shows that lower load at 139 TWh in 2020 (rather than 148) would lower net benefits of the project as it was envisioned then by $760,000. The 2014 study increases that to a loss of $1.77 billion. Because the period covered by the project has changed these values are only indicative. That said, the load forecast that the IESO study relied on in this case shows 2020 load as 147 TWh, remarkably close to the 2014 study assumption. We now know that the Ontario Planning Outlook (OPO)

[4] For simplicity we refer to operation after 2018 as PEO despite the inclusion of aspects that OPG has characterised as PCO in the early period.

indicates that 2020 load is forecast at 138 to 142 TWh in scenarios A and B. The more aggressive scenarios C and D are described by Mr. Pietrewicz as "a very, very aggressive electrification of the Ontario economy"[5]. Those scenarios are described in the Outlook document as requiring a 25% and 50% share respectively of the gas heating market to switch to electricity. However, as the Board will be aware, the government has backed off its initial proposal to aggressively move space heating loads off gas in the next few years and these more aggressive scenarios will therefore not come into play in the 2018-24 period that is relevant to the PEO analysis. But even these more aggressive scenarios are lower than the forecast utilized in the IESO PEO study throughout most of the period[6]. Accordingly, from the information available on the record, we now know that the earlier study conclusion of cost-effectiveness of PCO was in all likelihood wrong and the Board should not feel constrained by its earlier conclusions on PCO given this new information. Further, the only reasonable conclusion to be drawn is that the lowering of the load forecast has moved the PEO project from the black to the red.

Like the IESO, OPG assumed 147 TWh in 2020 growing to 152 in 2024 a far cry from the level or declining load in the relevant current OPO forecasts.[7]

The trend is clearer if we consider the December 2016 Reserve Margin report where the IESO provides the following single line forecast that it actually uses for reserve margin analysis. It shows grid load falling from 137.4 TWh to 133.6 TWh over the period 2017-2021[8].

Table A1: Annual Energy Consumption and Peak Demand

Year	Demand Forecast	
	Energy (TWh)	Peak (MW)
2017	137.4	22,680
2018	135.7	22,519
2019	134.0	22,357
2020	133.4	22,192
2021	133.6	22,479

[5] V. 8, p. 94, L-6.5-1-Staff-125
[6] L-6.5-8 GEC-43
[7] L. 6.5, Staff 125 discussed at V. 13, p. 183
[8] K. 13.3 section A4. J12.5 provides the NERC LTRA demand forecast adjusted to Net Demand, consistent with the forecasts used by IESO in the PEO analyses. Peak Demand in 2018 is at 24,073 MW moving only slightly by 2024 to 24,186 MW.

The Ontario Planning Outlook also show load falling throughout the PEO period in scenario A and level in scenario B whereas both the IESO and OPG studies in support of PEO have load rising throughout the period.[9]

Thus the best available information on the expected load predicts an economic loss due to PEO that in all likelihood far exceeds the benefits that either IESO or OPG identified in the past. *Prima facie* PEO is a loser. OPG has elected not to provide updated evidence indicating otherwise and in GEC's submission could not do so.

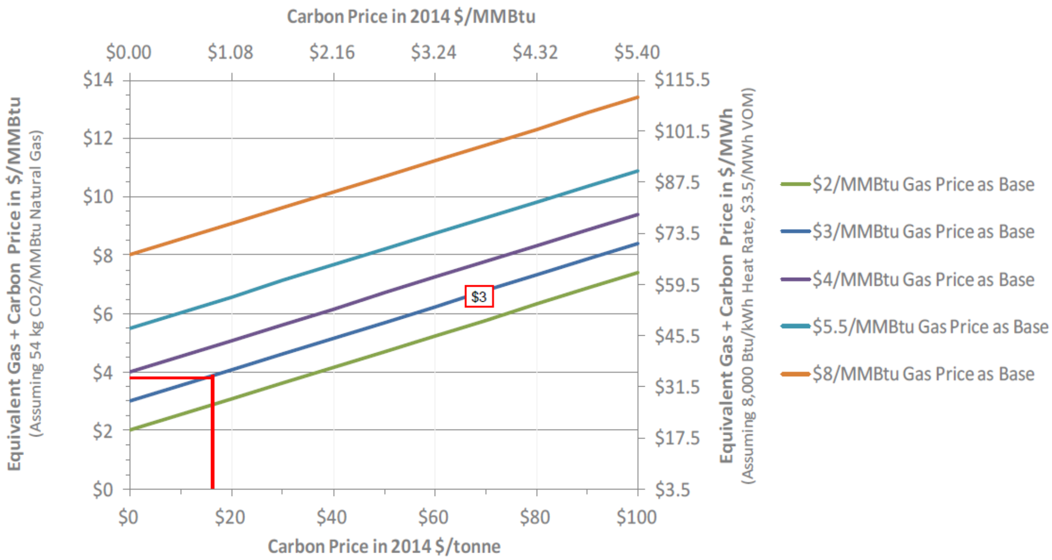
d) Lower gas plus carbon costs also wipe out any possible PEO economic benefit

The IESO studies assume a US$5.25 Henry Hub gas price (2015 dollars).[10] OPG assumes a $4.3 to 4.7 price for gas in its analysis.[11] The IESO reports that PEO has value when gas or combined gas and carbon prices exceed $4.7 in 2015 dollars.[12] However the evidence shows current Henry Hub future prices for 2018 to 2024 averaging $3.03. [13] As futures prices are in nominal dollars the 2015 dollar equivalent would be well below $3.00[14]

OPG reports that it utilized a carbon price of $24.7 in 2018 rising to $34 in 2024[15] but the 2016 Ontario Planning Outlook expects the price to average $16.30/tonne for the 2018-2024 period (roughly $15.97 in 2015 dollars).[16]

Gas and carbon values can be combined using the IESO chart into an equivalent total cost:

[9] L-6.5-1-Staff 125
[10] F-2-2-3, Att 1, p. 93
[11] L-6.5-S 1 Staff 125 page 2. Note as well that OPG also utilized a Dawn Gas value that it assumed would be more expensive than Henry Hub prices but the (untested) information from Navigant provided by Environmental Defence suggests that situation has reversed.
[12] V.8, p. 56
[13] J8.5 March 13, 2017 values
[14] See J8.5 where with all values expressed in nominal dollars IESO's estimate is 90 -106% above NYMEX
[15] L-6.5-S 1 Staff 125 page 2 but see Ex. F2-2-3 Att. 2, Figure 3 which appears to assume a $40 price for carbon
[16] K.12.1 p. 37



Source K.12.1, p. 38

The $3.03 average Henry Hub price plus the $15.97 average carbon value results in an equivalent Gas + Carbon combined price of approximately $3.80 as opposed to the $5.25 gas value assumed by the IESO or the approximately $5.50 value that would equate to OPG's average assumed $4 gas plus average $30 carbon.[17] This is well below the $4.7 break even.

For both gas and carbon the forecasts are lower in the early years when more PEO production would occur and when discounting would have less effect, so using these averages understates the net cost of PEO versus alternatives.

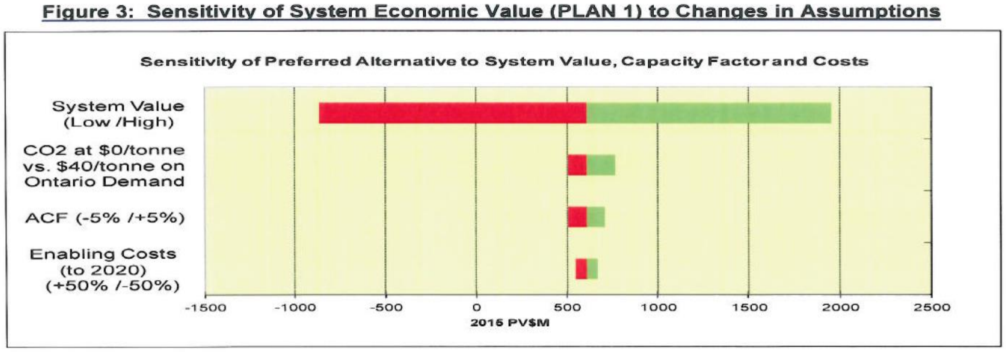
IESO does provide a sensitivity analysis if one assumes the lower gas costs seen in the 2010 – 2015 era (i.e. with the advent of fracking). The IESO chart reproduced below shows **a 70% likelihood that PEO will result in an economic loss to ratepayers.**[18] Mr. Pietrewicz also agreed that a lower load forecast would amplify this likelihood.[19]

[17] The use of this chart was discussed at V. 12, p75 *et seq.* All values in 2015 dollars.
[18] F2-2-3 Att 1 page 18. (and note that OPG has indicated that the 62 TWH scenario is the more accurate than the 65 TWh – see K 8.1 p. 18)
[19] V. 12, p. 78

The 30% probability of PEO saving money (in the 62 TWh scenario OPG's expects) is relative to a 2020 shutdown. As discussed below, the likelihood and scale of loss is even greater when compared to a 2018 shutdown.

OPG's report identifies system value (i.e. avoided gas and capacity costs) as the dominant factor.[20]

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



The updated information on predicted gas plus carbon cost of approximately $3.80 is significantly lower than the approximately $5.50 combined value equivalent to OPG's assumed gas and carbon costs. To ignore this would be willful blindness.

Further, there are likely cheaper and cleaner options available in the form of imports and demand response. DR (which emits no carbon) has recently been acquired for a cost of $83

[20] F 2-2-3 Att 3 Fig 3

versus the $130/kW year assumed for capacity by IESO.[21] Quebec power has also been acquired for less than the cost of gas-fired power.[22]

e) Optimistic production forecasts bias the studies

Mr. Pietrewicz acknowledged that the IESO studies utilized OPG's information to inform production forecasts but that he had not analysed the over-forecasting pattern that is evident and did not include a sensitivity analysis based on forecast variance.[23] A comparison of OPG's nuclear production forecasts as approved to actuals for the years 2008-2015 shows an average 3.2 TWh/yr over-forecast on approximately 50 TWh/yr or 6.4%.[24] Virtually the entirety of the net benefits identified in the OPG and IESO studies would disappear if this one adjustment is made.

f) The Surplus Baseload Generation problem stems from Pickering Extended Operation

As discussed in the IESO 2016 Operability Assessment, Ontario experienced SBG conditions approximately 66% of the time in 2014 and this is expected to increase to 72% of the time by 2020.[25] The IESO chart reproduced below shows how PEO is responsible for roughly ¾ of the problem:

[21] See discussion at v.8 p. 111 and at p. 124 where it is noted that the IESO didn't look at how much incremental DR there would be and the cost of it, and is still not sure. To get a sense of how fragile the PEO assumed benefits are, If we were to change this one assumption by assume that the $800 million gas peaker capacity costs IESO estimated (based on the $130 figure) could be replaced by $83 dollar DR, that saving alone would all but offset the IESO's assumed PEO benefit of $300M: (130-83)/130 X 800 = $289

[22] V. 8, p. 136

[23] See v. 12 at pp. 105 et seq

[24] E2-1-1 p.3

[25] K.12.1 pp 42-44

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Exhibit F2-2-3
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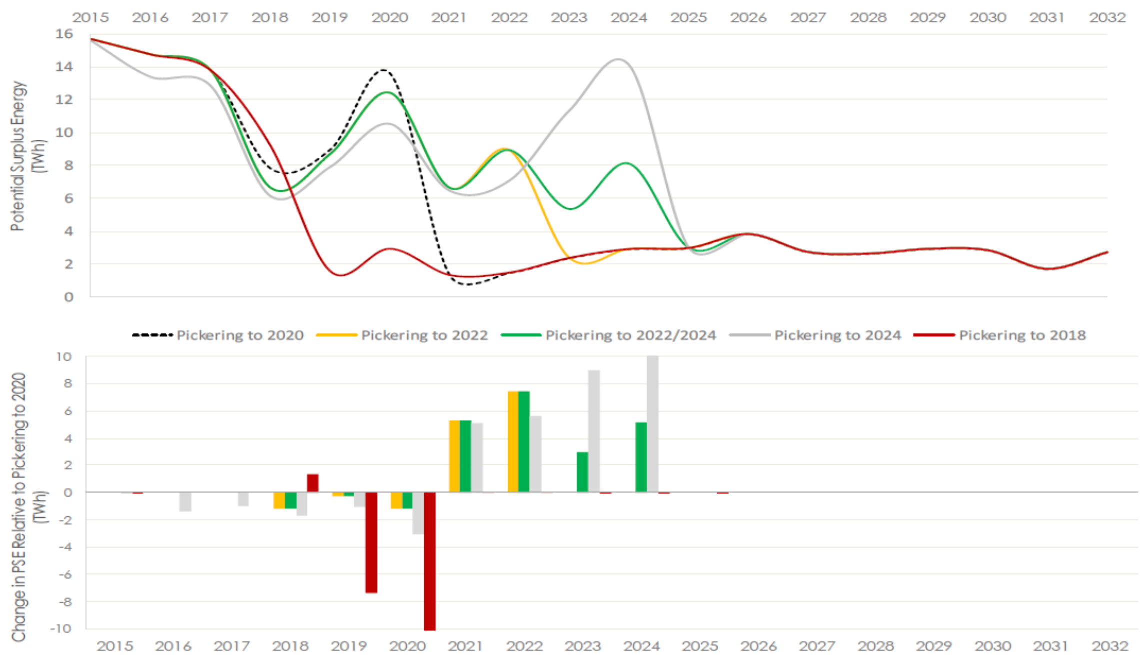
Energy production from Pickering increases potential surplus energy



g) Need

The IESO's interest in maintaining Pickering as "an option worth continuing to explore"[26] is largely about maintaining flexibility to meet system peak demand. The IESO evidence indicates that Quebec has "an abundance of energy, but currently has a capacity shortfall during the winter peak."[27] Of course, Ontario is a summer peaking jurisdiction so increasing exchange is mutually advantageous and Quebec's peaking problem in winter is not relevant to the question of meeting Ontario's summer peak.

But even assuming that Ontario's winter peak becomes more of an issue, the IESO indicates that "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 the coming years, taking advantage of resource options via capacity options (SIC) [auctions], and greater use of non-firm intertie transactions."[28] IESO also indicates that it is

[26] K.12.1, p. 41
[27] K.12.1, p. 18
[28] L 6.5-8 GEC 56b

possible to replace Pickering output in 2018 by launching new rounds of resource acquisition[29]. Mr. Pietrewicz clarified that there is no energy supply issue just a peak capacity concern and that amongst other options, existing NUG contracts that are near completion could be renegotiated and extended to address that.[30] He indicated that the need for an actual plan to address non-approval of PEO could wait until 2018 as "I would say starting in the early 2020s is when we would start seeing, I think, from my current perspective, the effects of no Pickering continued operation on the resource adequacy picture."[31]

In its September 2016 report to NERC, IESO provides a single line peak demand forecast for reliability considerations and that forecast is described in the 2016 LTRA Narrative Guide as "The average annual growth in the Ontario Total internal demand forecast is -0.1% during the 10 year period, a decrease since the 2015 LTRA report which forecast 0.1% average annual growth."[32] In other words, the IESO reports that its demand forecast for the next ten years has fallen since the Pickering studies were done.

For the purposes of this proceeding it is not necessary for the Board to resolve this question of need. Nor is that determination to be made by OPG or the IESO. The new regulatory regime places that decision in the hands of the Government and it has indicated that it will do so after considering all options available and after hearing from the Board on the economics. In GEC's submission, the Board's responsibility is to illuminate the economics and provide a determination of appropriate payments to be made in the case with and without PEO. Rates can be set on an interim basis for 2017 and 2018 and finalized after the government has made its determination in light of the Board's findings on economics and the CNSC's determinations on licensing.

h) Carbon impact

As discussed above, Pickering's output can be met to some significant degree by carbon free imports at times other than system peak. Existing NUGs and imports (including non-firm imports) can provide for system peak. The small amount of time that carbon based fuels would

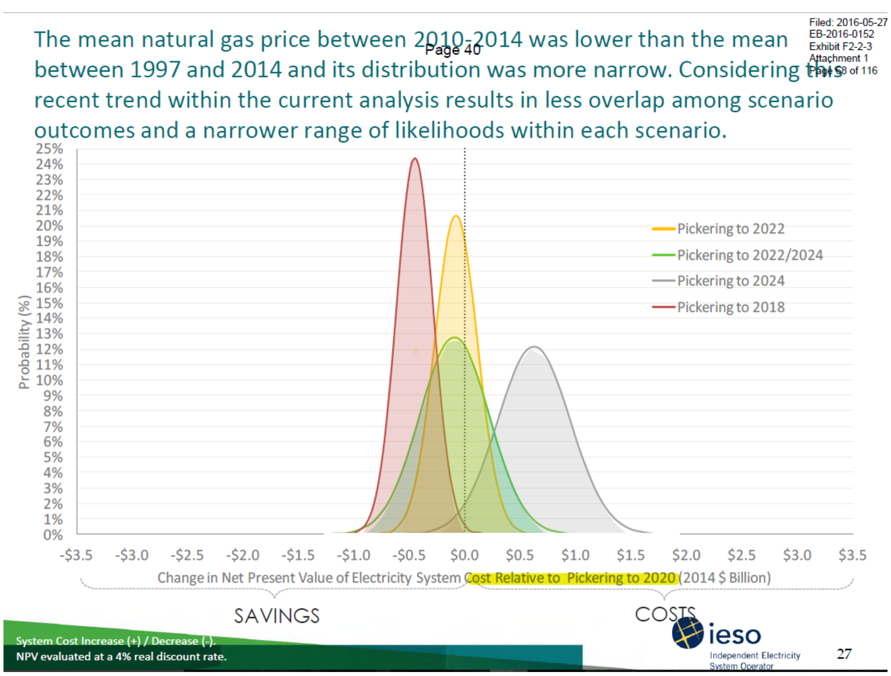
[29] L. 6.5 S.1 Staff 132.
[30] V. 8, p. 66: "we wouldn't propose to build new plant to replace the energy from Pickering. In fact, they would come from the existing system, just at higher levels of utilization, so our existing gas plants would operate at higher capacity factors. We would see less curtailments of renewables than we do today, for example. So the energy picture could be addressed by our existing system, which still has a lot of energy production capability left in it. However, to meet peak requirements these are requirements to meet a small amount of hours in a year, just at the highest demand hours."
[31] V. 8, p. 104-105
[32] K.12.1, p. 15

be required for that purpose means that the carbon impact would be minimal. Moreover, as the significant outages of the past demonstrate, reliance on nuclear to address emissions reduction is a risky strategy. Demand Response is a far more diversified and reliable approach to addressing peak capacity. The cap and trade regime now in place captures both domestic and imported power and we would expect that regime will be managed to be effective, so that any increase in domestic gas generation would have to be offset by demonstrable emissions reductions elsewhere and overall[33]. As in the matter of need, the Board's mandate does not include this issue directly. Again, the government will consider this factor in its ultimate decision. However, the Board needs to be cognitive of carbon costs and as noted above, including these costs does not make the project economic.

i) 2018 vs 2020

OPG and IESO have cast the debate as the relative merits of a 2020 shutdown versus a 2022/24 shutdown. However, with the Clarington transformer scheduled to be available in 2018 the economically superior option of a 2018 shutdown must be on the table.

Gas prices and load forecasts have fallen since the Board considered this in the previous case. As OPG's 2015 analysis demonstrates, a 2018 shutdown is now the least cost scenario for Ontario ratepayers:



33 See V. 12, p. 14 where the inclusion of imports in the cap and trade regime is acknowledged by IESO

j) Cost (disbenefit) will only go up

As discussed throughout this proceeding, OPG's terrible cost control problems on the campus projects of the DRP have been attributed to work proceeding before all engineering is complete. In the case of PEO one third of the assessment and scoping has not been finalized:

> MR. BLAZANIN: The business case will be updated based on finalization of the scope of work that will be completed.
>
> MR. POCH: Right. And that scope of work is not, as you say, finalized at this point in time.
>
> MR. BLAZANIN: It is not fully finalized. The major life cycle management plan work, which represents probably two-thirds of that, has been defined and is being refined, and the balance of plant equipment is being finalized through the component condition assessment and PSR work.[34]

Given the potential for these further equipment assessments to indicate the need for expanded scope, it is clear that the cost risk for the project is not symmetrical.

Further, the IESO and OPG have not done a sensitivity analysis for Pickering production.[35] This is another asymmetrical risk.

Finally, while the IESO did provide some statistical analysis of the risk of disbenefit due to gas prices, the IESO and OPG have not combined the various risks in their analyses (for e.g. by utilizing a Monte Carlo technique). Accordingly, the cumulative likely disbenefit will be larger than that due to any one source of risk, and that likelihood of disbenefit has not been made apparent.

k) Pickering - Conclusion

It is beyond doubt that Pickering Extended Operations beyond 2020, and *a fortiori* beyond 2018, will in all likelihood be severely cost ineffective. Environmental Defence, in its

[34] Vol. 13, p. 179
[35] Vol. 12, p. 103

submissions, has provided estimates that range from over $1B to over $2B in net costs. To facilitate an informed government determination on the project GEC submits that the Board should clearly reflect these observations in its report. In GEC's submission, rates should be set that assume no operation of Pickering beyond 2018 and that do not cover the unspent costs of the PEO project itself. In that scenario, should the government's broader consideration determine that Pickering should nevertheless continue operations beyond 2018, the costs can and should be addressed via a directive. Alternatively, in the circumstance that the government concludes the project should proceed despite being non-economic and the Board concludes that Pickering costs should be addressed in that scenario in the payments, then the Board may wish to set rates on an interim basis for the 2017-18 period and provide a determination of appropriate payment amounts with and without PEO to enable rate finalization following a government determination on need.

2. Issues 2.2, 4.1, 4.3, 4.5 -- Darlington Refurbishment Program

Regulation 53/05 has deemed need for the Darlington Refurbishment Program (DRP). However, government policy as expressed in the LTEP has called for explicit off-ramps and risk containment. Accordingly, GEC's focus in this proceeding is ensuring that the true costs and ratepayer risks of the DRP are illuminated, and that information and reporting are adequate to support a timely and informed off ramp process and consideration by the government. Further, GEC submits that OPG's accountability and its incentive for cost control will be impacted by two matters before the Board; the interpretation of section 6.(1)4. of regulation 53/05 and the manner in which the Board will apply its prudence test for the project as a whole and for the expenditure of the significant contingency budget. Finally, GEC submits that the prudence standard OPG proposes, 'consistency with industry best practices', is inadequate given the routine failure of the nuclear industry to control capital costs.

a) Reg. 53/05 precludes Board approval of costs that have not already been incurred or firmly committed to.

OPG proposes that the entire capital outlay to bring Unit 2 on line in 2020 should be approved in the capital budget for rate base inclusion as part of this proceeding. GEC submits that the explicit statutory framework for the DRP precludes such treatment for the approximately $2 billion of DRP Unit 2 costs that have not already been incurred or for which a firm financial commitment has not been made.

GEC's submission is based upon the following interpretation of the statutory framework:

Section 78.1(4) reads as follows:

> (4) The Board ***shall*** make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment. 2004, c. 23, Sched. B, s. 15. (emphasis added)

The inclusion of the word 'shall' makes the requirement that the Board's payments order be in accord with the regulations mandatory and that the rules in the regulation must displace the ordinary approach of the Board. Thus the ordinary Board practice of approving capital budgets on a forward basis using a test of reasonableness is supplanted by the specific regulatory mechanism provided by the regulations.

Regulation 53/05 provides:

> 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… (emphasis added)
>
> ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., **if the Board is satisfied that the costs *were* prudently incurred and that the financial commitments *were* prudently made.** (emphasis added)

Given the maxim of statutory interpretation, *expressio unius est exclusio alterius,* the specification in the legislation of mandatory payments for costs and commitments already incurred must be read to exclude the payment for costs and commitments not already incurred. Accordingly, only costs and firm commitments already incurred can be considered at this time for recovery or addition to rate base during the rate period.

It is also important to note that the 'financial commitments' referred to in subsection ii are defined in the first paragraph of section 6.(2)4. as '***firm*** financial commitments'. Given the explicit government direction to OPG to maintain flexibility in its DRP contracts and OPG's ability to cancel without penalty for any reason, it is abundantly clear that unspent funds are not firmly committed apart from the amounts that OPG has indicated are accrued or it is contractually committed to pay for demobilization.[36] Adjusting for those accruals and commitments, the non-incurred costs are described by OPG as $2130 million "unspent and not committed" as of December 31st 2016.[37]

b) DRP spending, whether spent or firmly committed or not, cannot be judged prudent or reasonable at this stage

Even where funds fall under the Regulation 53/03 phrasing of already incurred or firmly committed, the Board cannot include them in rate base and payments unless it is "satisfied that the costs were prudently incurred". In a situation where billions remain to be spent over many years initial expenditures can only be said to be prudent with a determination that the entire project budget is reasonable and attainable. GEC submits that OPG has not demonstrated that it optimized its budget or contracting strategy or contract details, nor does its proposal of 'industry standards', from an industry rife with failure, provide a suitable benchmark or standard of review to enable the Board to judge prudence.

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[36] OPG notes the inclusion of Termination for Convenience provisions: "OPG may terminate the contracts for convenience at any 21 time, providing an important off-ramp to OPG", OPG argument p. 47. Termination costs are discussed at V. 4, p. 11 to 16.

[37] J4.1

OPG asks the Board to approve close to half the estimated cost of the entire DRP program at this time as attributable to unit 2. Counting capital, DRP related OM&A and related costs, that amount exceeds $5 billion of the $12.8 estimate for the DRP[38]. No one would propose a single reactor refurbishment costing over $5 billion.[39] OPG can only justify $5.3B (or more than $5.6B including D2O facility costs) based on a 4 unit plan. Accordingly, spending over $5 billion for a single rector refurbishment cannot be prudent or reasonable unless those common costs that are included with the first reactor will serve the other 3 reactors. If the overall DRP is or turns out to be imprudently costed or is mismanaged the expenditure of over $5 billion on unit 2 and common costs cannot be prudent. But OPG has refused to respond to questions about units 1, 3 and 4.[40]

More fundamentally, OPG has not demonstrated that its total project cost is reasonable.

OPG has stated:

> "There was no third party review undertaken to verify or validate the final schedule duration, cost estimate, or scope definition for the refurbishment. The purpose of the third party reviews of the RQE was to validate that the processes and practices to develop the final cost, schedule, and scope for refurbishment met or exceeded industry standards, and, to confirm that OPG was effectively following those processes and practices."[41]

Lest there be any doubt about this, the matter was also canvassed by the Chair:[42]

> MS. LONG: Thank you. Mr. Janigan took you through a number of expert -- well, reports that you filed to demonstrate reasonableness, and those reports deal with governance. They deal with methodology. They deal with process. But is there anywhere in the evidence where you filed a report or commentary on any independent assessment of the actual costs of this project, be it the 12.8 or the 4.8 billion? Is there anybody who took a sober second thought at that and said, "Yes, 4.8 is reasonable; 12.8 is reasonable"? Not how you did it, not the methodology, not the risks that you identified, but the actual numbers?

The answer was that OPG deemed that too difficult to do. The sole exception being the turbine package.

Prudence is to be judged on a prospective basis. Would a reasonable actor proceed as planned based on what was or should have been known at the time? But that requires the actor to have been diligent in understanding the facts available. Accordingly, while theoretically the Board

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[38] Discussed at V.1, p. 136
[39] Discussed at V.1, p. 143
[40] Exhibit L, Tab 4.3, Schedule 2 AMPCO-031
[41] L-4.3, S.2, AMPCO-101
[42] V. 2, p. 173

could find reasonableness based on what could be known today, OPG has not diligently equipped itself and the Board with a sufficient factual basis for such a judgement to be made.

And despite a specific government direction to externalize risk in its contracting approach, OPG did not obtain bids with alternative risk allocation approaches that could lower ratepayer risk and inform us of the reasonableness of the costs and risks OPG has taken on.[43] OPG suggests that to do so would just result in unaffordable bids. That may be so, but wouldn't that then indicate that the project costs plus risks are unreasonable?

Nor can OPG provide any report on cost benchmarking.[44]

On what basis and with what evidence can OPG claim that the $12.8 billion or $4.8 billion is a reasonable estimate for the program and is a reasonable cost? The directive deeming need does not equate to a directive to find costs or approach reasonable regardless of the costs or approach. The Board is being asked to engage in a legal fiction – finding reasonableness or prudence with little or no evidentiary basis for the $4.8 billion figure.

Apparently, OPG's answer is to say its 'approach' meets or exceeds 'industry standards', an inadequate standard which we address below.

c) OPG has proposed an inappropriate standard for approval of the DRP capital budget

If the Board elects to consider the reasonableness of the DRP or aspects thereof, it must base that on some standard. OPG's proposal of 'industry standards' is in GEC's submission a recipe for failure.

Dr. Roberts commented: "Because the vast majority of mega-projects 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"

Past nuclear builds in Ontario have on average experienced 250% cost overruns. More recently the rebuild of Point Lepreau went from 18 to 55 months and $1B to $2.4B with related costs. Bruce A refurb was supposed to take 25 months and took 84 and went from $2.75B to $4.8B. Current projects elsewhere are faring no better. Completing Watts Bar in the U.S. was supposed to cost $2.5B and is now expected to cost 4-$4.5B. Flamanville 3 in France as of 2015

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[43] L-4.3-8 GEC 3, and V. 1, p. 150, and see the LTEP principle: Minimize commercial risk on the part of ratepayers and government.

[44] L-4.3-3 CME 18

had grown from 3.3B Euros to 10.5. Hinkley Point C in England has gone from 6 billion Pounds to 18 billion.

OPG claims it has learned lessons from past nuclear misadventures which seems a clear recognition that industry standards have failed, and as the discussion with OPG's first panel makes clear, learning from others mistakes has not been a panacea elsewhere:

> MR. POCH: You know, we have any number of nuclear mega -- megaprojects, in general, happening around the world, nuclear in particular, that are going sour. Are you suggesting that those projects, they haven't made a good attempt to learn lessons and meet industry standards?
>
> MR. REINER: They do. Every project does….[45]

In short, OPG offers no reasonable basis upon which to judge its proposal reasonable. In such circumstances, the Board has no basis to approve such costs. To provide optimal incentives for cost and risk control, OPG should remain at risk to the greatest extent feasible.

Finally, in its argument OPG recites Mr. Lyash's comments on the incentives that OPG has to control project costs. We simply point out that OPG and similarly situated nuclear proponents elsewhere have had these same incentives for the projects to date, projects that almost universally have experienced significant cost overruns. Mr. Lyash's incentives are not a substitute for accountability and cost exposure, they didn't save his past nuclear projects.

d) OPG has failed to respect the Directives

In EB-2013-0321 the Board indicated that it would not opine on the alignment of the DRP with the LTEP. At p. 64 the Board said:

> The Board will not opine on whether OPG's nuclear refurbishment process for Darlington aligns with the Government of Ontario's Long-Term Energy Plan. The Board considers this review to be outside of its mandate. A key component of the principles outlined in the Long-Term Energy Plan is the appropriate allocation of risk as it relates to nuclear refurbishment. The Board is of the view that for the reasons previously stated, the amount of evidence related to appropriate risk allocation would be insufficient for the Board to reach such a finding.

Nevertheless, OPG seeks the Board's blessing of its contracting approach in this case as part of its request for a finding of reasonableness.

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[45] V.1, pp. 147-148

The first of the seven LTEP principles is: *Minimize commercial risk on the part of ratepayers and government.*

In EB-2013-0321 GEC submitted, and the Board agreed, that "The evidence suggests that OPG bears the primary risk for overruns with respect to 93% of the program costs."[46] OPG had responded that the 93% includes OPG internal costs. In GEC's submission, that misses the point, whether internal or contracted, these risks will be borne by ratepayers or taxpayers not contractors. In the present case Mr. Lyash responded by noting how risk is minimized through other mechanisms like training and testing of tooling, but his examples do not respond to the directive requiring OPG to minimize 'commercial risk' which must certainly be largely about risk allocation in contracts.

In that regard OPG has simply failed to externalize risk as directed and has failed to even adequately investigate the options:[47]

> MR. POCH: But if this Board is interested in your compliance with the long-term energy plan, with the principles -- and one of those is minimizing risk. We all understand, if you minimize risk, the price is going to go up. You buy insurance; it costs something. You don't have a report you can lay before us showing how you tested that, those waters, and what that curve looks like. You've made that call. You made that call early on, and you don't have anything further to offer us now.
>
> MR. REINER: We don't have anything that you're describing that goes with that -- with that principle…

Mr. Reiner goes on to report that OPG looked at Lepreau where a fixed price approach was taken and the project went bad. However, because that matter is subject to litigation he could not conclude that the fixed price contracting approach failed to protect ratepayers. OPG seems to have simply rejected any approach that further externalizes risk because it would raise the price making the project less politically feasible. This simply ignores the real cost of risk and the government directive to reduce that total cost.

In this case ED asked IRs and obtained undertakings that illustrate how the risk is shared given the various procurement contracts – in JT1.20 we see in the 25% overrun example that OPG would end up with about 85% of the cost overruns. OPG points out that these overruns would at first be met by the contingency budget, but that does not address the issue – ratepayers are being saddled with this risk.

Further, risks such as inflation and interest rates were not included in OPG's determination of contingency allowances.[48] Who bears those risks?

[46] EB-2013-0132 Decision p. 56
[47] V.1, p. 150

And if the project takes longer than expected, ratepayers pick up the energy replacement costs not the contractors.

OPG's response to these observations seems to be that effectively externalizing more risk would have cost more. Of course, that's to be expected when one buys insurance, as OPG was directed to do but elected to avoid.

e) OPG has obscured the true costs of the DRP

I. Increased cost of capital for the balance of OPGs rate base should be attributed to the DRP

OPG is requesting a higher equity ratio to reflect the risk of the added capital investment in nuclear resulting from the DRP. The higher cost of capital will apply to the entire rate base including the hydraulic assets. This higher cost was not captured in the DRP cost estimate or LUEC.[49]

II. Rate smoothing interest costs should be attributed to the DRP

Regulation 53/05 defines the deferral period as ending when the DRP ends. Absent smoothing the non-smoothed rate was relatively smooth but for the discontinuity in 2020 with the coming into service of unit 2.[50] Clearly, the government's directive to rate smooth is precipitated by the DRP rate impact. Rate smoothing is predicted to have a $1.4 billion interest cost to ratepayers. These costs (and the intergenerational inequity they imply) are properly attributable to the DRP.

III. Misallocation as between DRP and Nuclear Operations

Since the last case OPG has reallocated $860M from DRP to Nuclear Operations.[51] One relatively minor but illustrative example is the $28.6M OPG share of accelerating the Holt Road 401 interchange costs. Mr. Reiner agreed that the cost is being incurred to accelerate the work to be available for the DRP. He agreed that if Darlington was instead to be retired "We would have looked at it to see whether it was necessary to advance that project."[52]

These costs had been included in the business plan that led to the approval of the DRP but are now (inappropriately in GEC's submission) excluded from the DRP budget, making it easier for OPG to appear to have met it's $12.8B budget and obscuring the true total cost of the project which remains relevant for the government consideration of off-ramps.

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[48] V. 1, p. 167 and L-4.3-2- AMPCO 71 part c
[49] V. 4, p.41
[50] See K1.3, p. 45
[51] L-4.5-2 AMPCO-105, discussed at v.4, pp.18 et seq
[52] V.4, p. 20

Similarly, OPG has moved $129.5M of PHT pump motor replacements out of DRP costs despite some of these pumps being put into service after the date when the associated Darlington unit would be out of service absent the DRP. (The planned final in-service for these pumps extends to December 2022 when 3 of 4 units would have been retired.) While some of the pumps are or will be in service prior to that time, the portion that will not be are clearly only required because of the DRP. OPG witnesses say these items are all in the LUEC as they would be picked up as capital additions during the life of the refurbished plant, but that misses the point.[53] By moving the expense from DRP to Darlington operations but keeping the DRP capital cost at $12.8B OPG has effectively increased its DRP budget without transparency and made it easier to appear to be on target.

The same situation exists in regard to $26.6M of powerhouse water-cooled unit replacements with target in-service dates from December 2019 to January 2023, i.e. a period ending months after three of the four reactors would otherwise be out of service.[54] Surely, OPG would not be investing in all of these cooler units but for the DRP.

These reallocations will cumulatively reduce OPG's cost control accountability for the DRP and obscure the facts that will be relevant to any off-ramp determination. The Board should deem these costs as a portion of the DRP or otherwise alert the government to this concern.

IV. Likelihood of Cost Overruns

OPG did not conduct a Monte Carlo simulation or historical analysis of escalation or interest rate risk and include that in its DRP cost estimate.[55] A 1% increase in interest rates or escalation increases the project cost by $800 million.[56] With escalation assumed at 2% and historically low interest rates it is obvious that the risk surrounding these variables is not symmetrical. OPG excluded these risks from consideration when developing the contingency allowance.

Mr. Lyash acknowledged the incomplete nature of OPG's costing when he noted:

> "while the output of the tool is a P90, I wouldn't say that, in the end, the project result would be less than that nine out of ten times, because to do so would be to ignore all the other factors we have to manage"[57]

[53] Vol 4, p. 27, l. 17
[54] L-4.5-5 CCC 22
[55] See V. 4, pp.30 et seq
[56] V.3, p. 41
[57] V. 2, p. 23

More significantly, the overall risk of nuclear project cost overruns cannot be understated. As discussed above, both past nuclear builds in Ontario and current experience worldwide amply demonstrate that the industry is incapable of cost estimation and cost control.

OPG's initial Darlington related projects (whether formally attributed to the DRP or to Nuclear Operations) seem to honour that history:

- The initial 'full release' of funds for OPG's Heavy Water Facility was $110 million. It is now forecast at $381.1 million.[58]
- The Darlington Operations Support Building went from $46.7 million to $61.1 million ($9.7 above the approved execution full BCS) to 62.7[59]
- The Darlington Restore Emergency Services Water and Fire Margins project is currently forecast to be $20.9M higher than the previous estimate.[60]
- The water and sewer project was a $40.6M project that is now $57.7M.[61]
- Electrical Power Distribution went from $16.9M to a final cost estimate of $20.8M.[62]
- The Darlington Auxiliary Heating System has increased since the last case by $14.4M to $99.5M.[63]
- The Security Physical Barrier System went from a full release of $49.5M to $67.2M.[64]
- The Vehicle Screening Facility went from a full release of $3M to $6.6M.[65]
- The Third Emergency Power Generator went from an original release of $88.2M to $120.4M.[66]
- The Emergency Service Buried Water Services went from $7.9M to $14.6M.[67]

OPG claims that the pattern of cost overruns on the initial Darlington projects will not occur for the balance of the program because these earlier projects proceeded prior to completion of engineering. In other words, OPG claims to have overcome its prior incompetence. This might be persuasive if OPG were new to the nuclear industry, but if OPG is an expert at anything it is the ability to experience major nuclear cost overruns. And if it has failed at cost control in the initial DRP projects despite being aware of those risks due to its long and storied history of

[58] D2-T.2-S.10 p. 16
[59] L-4.2-1-Staff-25 and L-4.3-2 AMPCO 30
[60] D2-1-3, Att 1, Tab 18
[61] L-4.3-2 AMPCO 30
[62] D2-02-10, p. 22
[63] D2-01-3, p. 9
[64] D2-01-3, p. 10
[65] L-4.3-2 AMPCO 30
[66] L-4.3-2 AMPCO 30
[67] L-4.3-2 AMPCO 30

major nuclear cost overruns, why should the Board have any confidence in its ability to estimate or control costs going forward?

Moreover OPG acknowledges that it has not completed planning for subsequent units:[68]

> MS. LONG: I'm sorry. I'm not clear on your evidence, Mr. Rose. So what you are saying is you've spent a billion dollars on planning. Your position is that is for the entire project. But I thought I heard you say there would be extra planning costs for the extra units past unit 2. Is that correct?
>
> MR. ROSE: There are -- so within each of the units, there's unit-specific engineering that needs to be done, unit-specific work planning that needs to be done, unit-specific scheduling that needs to be done.

Early indications from the August 2, 2016 Modus report on the execution phase suggest that all is not clear sailing. Modus highlights:[69]

- Schedule performance and adherence is an ongoing concern;
- While the technical tools are now in place, cost and schedule trending and forecasting are not mature;
- Aspects of key vendors' readiness for execution are a concern; and
- The Risk Management Program has not been fully embraced as an essential day-to-day management tool.

It is notable that the D2O fiasco that OPG has withdrawn from its payments request at this time is a project being conducted by the Joint Venture group that is responsible for the largest work grouping of the DRP. OPG cannot yet say whether the JV holds any responsibility for the problems at the facility but the event is certainly a cautionary tale.[70]

At some point during the currency of the rate period the government will be making a decision on off ramp utilization and will no doubt have regard to the Board's findings in this case. The Board should be cautious not to give a false signal of confidence in OPG's cost estimates.

[68] V. 3, p. 26
[69] L, Tab 4.5, Schedule 8 GEC-013, Attachment 1
[70] V. 1, pp. 132-133

f) A portion of OPG's cost overruns on early DRP projects should be disallowed.

OPG has admitted that it mismanaged the early DRP projects, proceeding before engineering was complete, failing to recognize that its emergency cooling pump house wouldn't fit the pump etc.. It is inconceivable that these errors did not increase costs beyond what a well-managed project would cost. Of course OPG would never admit that, and there are no benchmarks against which to test the appropriateness of costs because OPG (as in the case of the overall project) has not provided any. In the absence of such evidence the Board should disallow a portion of the costs in recognition of OPG's mismanagement, both as a matter of fairness to ratepayers and to send a signal to OPG that such cavalier management is not acceptable.

g) OPG must be accountable for its use of contingency

The DRP budget includes contingency allowances totalling $1.7B in addition to contractor held contingency budgets. GEC does not suggest that this amount is inappropriate in the sense of being too large. Given the history of nuclear cost overruns both in Ontario and currently worldwide, if anything, the contingency allowance is too small. However, GEC is concerned that OPG has proposed a prudence review mechanism that will obscure accountability for the spending of the contingency.

OPG asks for approval of $694M of contingency as part of its unit 2 request and OPG witnesses and counsel took the position that any subsequent review by the Board would be limited to any overspend.[71] Leaving aside the issue of whether Reg. 53/05 allows approval of costs not already incurred, OPG's approach would allow the company to mismanage part of the significant project costs and avoid accountability for that simply because the mismanagement is hidden by the use of contingency budget or by other aspects of the project coming in under budget. If these expenditures were below the Board's guidelines for materiality this might be a reasonable approach. Where we are talking about expenditures in the hundreds of millions it is not. OPG should be required to report on each draw on the contingency budget (or transfer from other budget items) and be at risk for that.

[71] V.4, p. 3

h) OPG should be required to regularly report in a meaningful way

In JT1.18 OPG has agreed to quarterly public reporting on Unit 2 safety, quality, cost performance and schedule performance. However, there are two issues with the commitment made in JT1.18. The first is that OPG has not agreed to publish the CPI and SPI quarterly.[72]

Second, reporting on the 'raw' figures showing the actual vs. forecast cumulative costs is still necessary even if OPG provides the CPI because the CPI is in effect a non-transparent black box. Provision of the raw figures will assist interested parties in understanding whether the underlying CPI and SPI methodologies have changed.

OPG should be required to provide both 'raw' figures on cost and schedule performance as well as CPI and SPI quarterly.

i) Darlington – Conclusion

Despite statutory wording precluding approval of non-committed costs, OPG seeks approval of the entirety of projected Unit 2 costs of the DRP. It does so having failed to provide any compelling evidence that its estimates are reasonable or achievable. OPG bases its entire case on meeting "industry standards" for project management derived from an industry that has demonstrated an almost unblemished record of dramatic failure when it comes to cost estimation and cost control. In the face of a clear government direction to minimize commercial risk for ratepayers, OPG simply dismissed alternative contracting structures that would have better externalized risk, not even testing those waters. By virtue of the regulations the Board must accept the need for the DRP but it need not, and in GEC's submission, should not, accept or bless OPG's inadequately supported cost estimates, or its inappropriate imposition of risk on ratepayers.

The government has required OPG to enable off-ramps and GEC urges the Board to be particularly cautious in its comments on the reliability of OPG's cost estimation as this will be a central consideration for the government going forward.

GEC submits that the Board cannot approve unspent or uncommitted funds and should not bless funds spent to date as reasonable in the absence of evidence demonstrating that the overall project is costed appropriately.

[72] See transcript vol. 2, p. 154, ln. 26 to p.159, ln. 27.

3. Rate Smoothing

The Board has been directed to implement rate smoothing with a view to making the payments more stable. However, the Board retains considerable discretion as to the extent of any smoothing. GEC submits that in exercising its judgement on the extent of smoothing the Board should be cognizant of the serious negative societal impacts of rate deferral.

Specifically, the Board should balance the desire to smooth payments with its statutory objectives to promote economic efficiency and cost effectiveness, and to promote electricity conservation and demand. Artificially lowering electricity costs will discourage conservation and the economically efficient use of electricity and will delay the arrival of competing cleaner alternatives.

Deferring costs will unfairly foist costs on future customers.

Deferral to the extent proposed by OPG will increase ratepayer costs by $1.4 billion due to interest charges.

Accordingly, GEC submits that rate smoothing should be minimized to the extent reasonable within the context of the regulation. The Board should have primary regard to the impact on ratepayers and society rather than on the corporate financial indicators that OPG has included in its weighing of alternatives.

All of which is respectfully submitted this 29th day of May, 2017.

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David Poch
Counsel for GEC