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OPG

EB-2013-0321

Board Staff Compendium

Panel 8

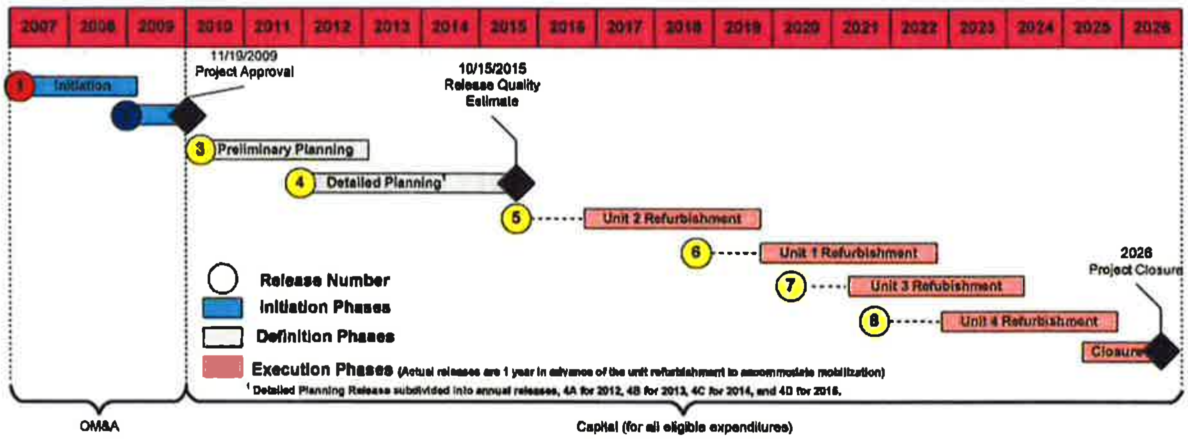
DARLINGTON REFURBISHMENT BUSINESS CASE SUMMARY
APPENDIX A – RELEASE STRATEGY AND DESCRIPTION OF WORK PHASES

1. Overview of Release Strategy

Funding for the DRP will be released in phases using a gating methodology, i.e. the project cannot proceed from one phase to the next without completing certain deliverables.

The overall release strategy is described in Figure 1.

Figure 1: Overview of the Darlington Refurbishment Release Strategy



This release strategy is based on an October 2016 1st unit outage and incorporates an October 2015, 2015 Release Quality Estimate ("RQE") date in order to incorporate the results of Re-tube and Feeder Replacement tooling production test results into the overall baseline schedule in order to increase Management's confidence in the projects scope, cost, and schedule estimate at RQE.

For the Detailed Planning Phase of the project, the releases have been sub-divided into annual release amounts, i.e. Release 4a for 2012, Release 4b for 2013, Release 4c for 2014, and Release 4d for 2015.

For the Execution Phase of the project, funding will be requested and released one year in advance of each individual unit outage to provide funding for mobilization of staff and to perform unit specific preparation including development of comprehensive work packages, unit specific planning and engineering, unit isolation and barriers preparation, and procurement of unit specific materials.

The sections below document the key deliverables for each release of the project. As the project progresses through the Planning Phase, further definition on deliverables and risks, may result in changes to timing and/or deliverables within each release, however, the phase-based gating methodology will be adhered to throughout the Darlington Refurbishment Project.

DARLINGTON REFURBISHMENT

1.0 PURPOSE

1.1 Purpose of the Darlington Refurbishment Project

The Darlington Refurbishment Project (the "DRP" or the "Project") is a multi-year, multi-phase program for Ontario Power Generation's Darlington Nuclear Generating Station ("DNGS") to enable the replacement of life-limiting critical components, the completion of upgrades to meet current regulatory requirements and the rehabilitation of components. It is comprised of individual projects of various scales and sizes that will be executed during multi-year outages.

The DRP, when completed, will allow the nuclear generating station to continue safe and reliable operation for an additional 30 years. Without refurbishment DNGS would cease production in 2020.

1.2 Approvals and Findings

This Exhibit D2-2-1 sets out evidence in support of the following findings and approvals that are sought by OPG:

- A finding that OPG's commercial and contracting strategies for the DRP are reasonable;
- A finding that the proposed capital expenditures of $837.4M in 2014 and $631.8M in 2015 are reasonable;
- Approval of OM&A expenditures of $19.6M in 2014 and $18.2M in 2015 (Ex. F2-7-1) ;
- Approval of in-service additions to rate base of $5.0M in 2012, $104.2M in 2013, $18.7M in 2014, and $209.4M in 2015 for new facilities and related 2014 and 2015 depreciation expense; and

- Approval to recover the capital cost portion of the actual audited nuclear balance in the Capacity Refurbishment Variance Account as at December 31, 2013, currently projected at $3.7M.

2.0 OVERVIEW

This exhibit sets out:

- The background to and an update of the DRP since EB-2010-0008 as well as a look forward to the test years 2014 and 2015;
- A description of and justification for the DRP's overall commercial strategy and the contracting strategy for the major project work packages forming the DRP;
- A description of in-service rate base additions for the years 2012 through to 2015;
- A description of proposed capital expenditures in the test period; and
- A description of the DRP-related balance in the Capacity Refurbishment Variance Account ("CRVA").

3.0 BACKGROUND AND UPDATE

3.1 Support for the DRP

The DRP is needed to ensure continued safe and reliable operation of the station for an additional 30 years.

As noted by the OEB in the EB-2010-0008 Decision with Reasons, OPG's Board of Directors approved the decision to proceed with the DRP on November 19, 2009. In its decision, the OEB found that the forecast DRP expenditures of $105.2M for 2011 and $255.8M for 2012 were reasonable. OPG indicated at that time that it would bring forward an update to the DRP and the planned expenditures and work plans in the next application.

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

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

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

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

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

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

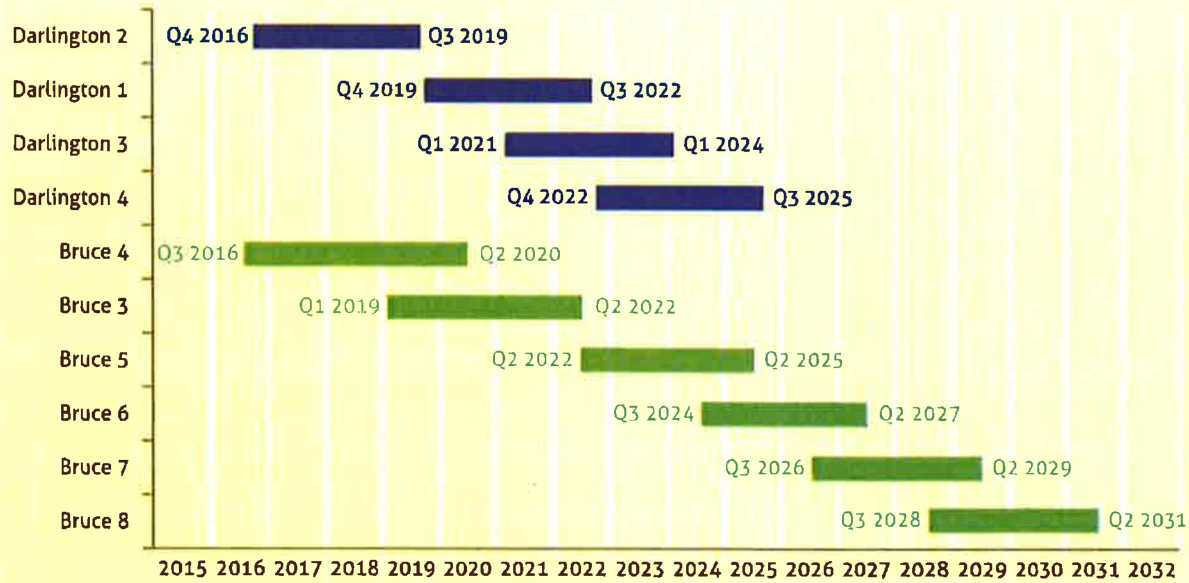
Ontario plans to refurbish units at the Darlington and Bruce Generating Stations. The refurbishment has the potential to renew 8,500 MW over 16 years. The province will proceed with caution to ensure both flexibility and ongoing value for Ontario ratepayers. Darlington and Bruce plan to begin refurbishing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

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

The nuclear refurbishment process will adhere to the following principles:

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

Figure 14: Nuclear Refurbishment Sequence



These principles reaffirm ratepayer value as the fundamental driver behind decisions on future refurbishment. The government will encourage the province's two nuclear operators, Bruce Power and OPG, to find ways of finding ratepayer savings through leveraging economies of scale in the areas of refurbishment and operations. This could include arrangements with suppliers, procurement of materials, shared training, lessons learned, labour arrangements and asset management strategies.

The continued operation of Pickering facilitates the refurbishment of the first units at Darlington and Bruce by providing replacement capacity and energy without greenhouse gas emissions while managing prices. However, an earlier shutdown of the Pickering units may be possible depending on projected demand, the progress of the fleet refurbishment program, and the timely completion of the Clarington Transformer Station.

The government is committed to nuclear power. It will continue to be the backbone of our electricity system, supplying about half of Ontario's electricity generation.

Renewables

Since launching the Feed-in Tariff (FIT) program in 2009, Ontario has firmly established itself as a North American leader in renewable energy.

To date, Ontario has more than 18,500 MW of renewable energy online or announced, which includes more than 9,000 MW of hydroelectric capacity and more than 9,500 MW of solar, wind and bioenergy capacity.

This is remarkable progress, and Ontario is proud of the role renewable energy is playing in the supply mix. This investment in clean, renewable energy sources is helping Ontario reduce its reliance on fossil fuels. The coal phase-out is the single largest climate change initiative in North America, reducing greenhouse gas emissions and air pollution. Coal use had accounted for $4.4 billion per year in health, environmental, and financial costs. At the same time, Ontario's clean energy initiatives have attracted billions of dollars in new private sector investment, and have contributed to the creation of more than 31,000 clean energy jobs across the province.

Earlier this year, the government committed to making 900 MW of new capacity available between 2013 and 2018 for the FIT (systems larger than 10 kW up to 500 kW) and microFIT programs. Starting in 2014, FIT will have an annual procurement target of 150 MW, with a 50 MW annual target for microFIT. These projects are expected to create more than 6,000 jobs while producing enough electricity each year for more than 125,000 homes. Annual price reviews for these programs are expected to reduce costs, as we saw in the recent price reviews.

The Minister of Energy confirmed provincial support for the refurbishment project as indicated in his March 8, 2011 letter to the Chair of OPG (Attachment 1).

> *The government is committed to continuing to use nuclear power to supply about 50 per cent of Ontario's energy supply. Achieving this goal will require the refurbishment of all existing units at OPG's Darlington Nuclear Generating Station. This refurbishment is key to the government's plan for modernizing the existing nuclear fleet. To this end I encourage OPG to efficiently manage the refurbishment process in a transparent and cost-effective manner.*

In 2012, the OPA performed its own economic assessment on the DRP (Ex. F2-2-3 Att. 2). The OPA stated:

> *On balance, the preservation of approximately 3,500 MW and 28 TWh of nuclear supply on an existing site with access to services and transmission is seen to have merit in terms of shorter lead-time, community acceptance, impacts on the environment and cost. In consideration of the longer-term uncertainties, the OPA's probabilistic analysis suggests a high likelihood that refurbishing Darlington NGS would be less costly than other sources of supply, including new nuclear or new gas-fired facilities, for a wide range of potential future conditions.*
>
> *In addition to the above considerations, the OPA estimates that the option would not add significantly to carbon emissions in the province. In comparison, an equivalent natural gas-fired alternative would increase CO^2 emissions by an average of 10 megatonnes annually between 2024 and 2054. This would approximately triple the annual volume of CO2 emissions for Ontario that is otherwise projected for the long-term.*

Further, the OPA views Darlington refurbishment as supportive of the diversity and performance of Ontario's long-term electricity supply mix. The rationale for a diverse supply

MS. GIRVAN: Okay. So I guess -- so I guess I am really looking at these amounts, the 67.2 and the 222.7, you are not seeking any approval of those? You are just saying these are the updated amounts for these particular elements of these projects?

MR. BARRETT: That's right. They are not reflected in the specific approvals for payments amounts and riders. Notionally they are captured within the approval that we are seeking for the capital expenditure amounts, for the capital expenditure amounts for '14 and '15 include these amounts plus other amounts.

MS. GIRVAN: Okay.

MR. BARRETT: You'll recall that was one of the approvals that we sought.

MS. GIRVAN: So when would the Board consider the prudence of the expenditures related to the list of projects, for example, on table 1?

MR. BARRETT: Well, in the normal course they would assess the prudence as a capital amount as going into rate base, so for the amounts that are going in in '14 and '15, that is when that assessment of prudence should happen, in my view.

MS. GIRVAN: So it would be the next payments case?

MR. BARRETT: No, again, we are proposing to add into rate base certain in-service amounts in '14 and '15, and they are part of our forecast revenue requirement for '14 and '15 and the proposed payment amounts and riders.

MS. GIRVAN: Richard, do you understand?

QUESTIONS BY MR.BATTISTA:

MR. BATTISTA: I had that same sort of question, because you are saying all these changes you are not intending to recover in your payments amount. So you filed an application in the fall, there was the February updates, now there are more updates, and the February ones you said, well, it washes out, so we are not going to change anything, or they are not material. You seem to be saying the same thing here, like theoretically then you are not closing it to rate base.

So in terms of your continuity schedules in D2, and those tables, they are either in or they are out, because what's going to happen is three years from now or whenever we won't know from a regulatory point of view what is the rate base and how much are any of the rate base change between, like, today and three years from now has been recovered from ratepayers or has been put in your capacity variance account.

MR. BARRETT: Just a couple of things in response. So again, the model that we have been using in this case and in prior cases is to file a set of information and then periodically file impact statements, and one of the things we use when we file those impact statements is a materiality threshold for making changes, and what we have talked about is a $10 million per year impact on the revenue requirement.

So if rate base changes, and rate base is constantly changing, forecast rate base is constantly changing, because projects have a natural ebb and flow to them, but if that rate base change doesn't produce a revenue-requirement impact of more than $10 million per year we don't flow it through.

So in terms of the rate base continuity, you will be able to track the rate base continuity. Eventually -- we have a forecast rate base in the application. It will eventually be actual numbers, which will be reported, and to the extent that the rate base forecast is approved, and with reference to these specific projects, if these in-service amounts are approved, we will be tracking the difference between these in-service amounts and the actual capacity refurbishment variance accounts.

MR. BATTISTA: So the rate base that the board is approving in this proceeding is the rate base presented in the fall?

MR. BARRETT: That's right. We have an updated rate base.

MS. GIRVAN: Okay. So to go back to my table 1, what you are seeking with respect to these projects are the 2014, the 18.7 million, and the 209.4 million, and what will happen is whatever you spend will eventually get trued up as your actual rate base.

MR. BARRETT: That's correct.

MS. GIRVAN: So we will see the flow-through of what you actually spend in the next payment amounts case?

MR. BARRETT: Yeah, in the same way that you would see in any forecasted rate base versus an actual rate base.

Table 1 – DRP In-Service Amounts

$ millions	Originally Filed Exhibit D2-2-1			As updated Exhibit N1-1-1 and D2-2-1 Attachment 5			As Updated Exhibit D2-2-2		
	Final In-Service Date	2014	2015	Final In-Service Date	2014	2015	Final In-Service Date	2014	2015
Darlington OSB Refurbishment	Jul-15	-	29.7	Oct-15	-	37.7	Aug-15	-	45.1
D2O Storage Facility	Apr-15	-	83.5	Oct-15	-	94.2	Jan-17	15.5	1.0
DN Auxiliary Heating System	Mar-15	-	36.3	Apr-15	-	43.5	Mar-15	-	75.3
Water & Sewer	Nov-14	12.2	-	Nov-13	-	-	Nov-15	22.6	6.6
Elec Power Distribution System	Apr-15	4.4	6.2	Jun-14	10.0	-	Nov-14	12.0	-
Darlington Energy Complex	Jul-13	-	-	Jul-14	6.0	-	Jul-15	2.1	4.1
RFR Island Support Annex	Apr-16	-	-	May-15	-	25.4	Apr-16	-	-
Other Campus Plan projects	various	-	-	various	10.2	-	various	15.1	7.6
Safety Improvement Opportunities	various	-	42.7	various	-	90.5	various	-	83.0
Other Station Modifications	various	2.1	11.1	various	-	18.7	various	-	-
Total		**18.7**	**209.4**		**26.1**	**309.9**		**67.2**	**222.7**

As indicated in Ex. N1-1-1, the in-service additions to rate base have increased for 2014 from $18.7 Million to $26.1 Million and for 2015 from $209.4 Million to $309.9 Million. The key driver, as reported in Ex. N1-1-1, of the higher in-service additions was earlier assumed in-service dates for certain safety improvement projects, including the Emergency Power Generator ("EPG") project and the Containment Filtered Venting System ("CFSV") project. These earlier in-service dates reflect commitments that OPG has made to the CNSC to have these projects in-service prior to the commencement of the refurbishment. Other contributors to the change include higher in-service additions for the Heavy Water Storage and Drum Handling Facility and the Re-tube and Feeder Replacement Island Support Annex.

As provided in this exhibit, the current forecast of in-service additions has increased for 2014 from $26.1 Million to $67.2 Million and decreased for 2015 from $309.9 Million to $222.7 Million. The key drivers of these changes to the in-service amounts were:

- A revision to the in-service dates for the Heavy Water Storage and Drum Handling Facility due to project engineering and construction delays.

d. The Gate Process and Failure to Report Cost and Schedule Increases to Senior Management

BMcD/Modus next explored the relative effectiveness of the gate process for this work, and found that while the process in concept is a good one, it suffers from problems in execution. The BCS documents for D2O Storage and AHS were inconsistent in presentation of key information on cost, risk and scope. As these projects progressed, P&M's management failed to provide visibility to OPG management of the extent or nature of project cost increases. Most notably, P&M failed to update its project reports during the design phase to reflect cost increases due to scope changes in the projects.

AHS provides a critical example. On November 12, 2012, P&M presented its Gate 3A package for approval and full funding release (except for a small portion of costs to be approved in 2014). The P&M Team's gate presentation characterized the AHS cost estimate as a Class 3 estimate in the amount of $45.6 M. P&M included $6.5M of contingency in the $45.6M estimate, of which $3M was identified as having a 100% chance of occurrence. P&M expressed an "85% confidence level" in this cost estimate and assessed there were 146 days of schedule contingency in the estimate—despite the fact that the full scope of the project was not known at that time because detailed engineering had not started. The option of building a new AHS was preferred over seven alternatives, based primarily on the projected cost. At the time of this gate, the project had spent $1.46M.

Between this gate and January 2014, [redacted] engaged in the design of the AHS, scope changes caused the cost to increase from the initial $45.6M estimate to $79.9M. This cost increase is largely attributable to two causes: (1) remediation of contaminated soil that as of the time of bid was known by both OPG and the contractor to be of poor quality; and, (2) prescriptive design requirements that served to make a stock steam boiler design follow nuclear Engineering Change Control ("ECC") processes, which caused an increase in the size, complexity and nature of the work. Moreover, these design requirements and the overall length of the design phase, coupled with the soil issues, has frittered away virtually every day of float.

The fact this project had so substantially changed from the original BCS was not accurately or timely reported to management. The failure of the gate process was that the Gate Review Board members did not provide adequate oversight in ensuring that the AHS project team had a reliable estimate, schedule, and well-defined scope prior to approving the gate and recommending a funding release. As of January 2014, P&M had already expended nearly $20M, or more than half the approved budget excluding contingency, even though the design was not complete and no construction had begun. However, during this entire time, P&M's estimate at completion ("EAC") in all of the DR Project's and Campus Plan reports ***never varied*** from the approved BCS amount. Moreover, the DR Project's Program Status Report for March 2014 showed the AHS at 49% spent with a CPI of 1.10 and an SPI of 1.0, clearly not an accurate representation of the Project's status. Part of this failure was based upon some of the P&M project managers' mistaken belief that the reported EAC amounts should not be changed until additional funds had been approved for the projects. This lack of accurate reporting has deprived senior management and the Board the option of revisiting the original BCS analysis in order to determine if building a new AHS facility continues to be the preferred option—and if not, change course. This is particularly true in light of the fact that as of November 2012, three of the competing options to building AHS were priced at less than $50 M.

D2O Storage provides a very similar example at a much higher overall cost. The cost variance progression from D2O Storage began with an original approved BCS of $110M, based upon estimated contractor costs of approximately $77.8 Million. [redacted] and design solution were both preferred but [redacted] was chosen entirely because its price was $30M less even before P&M further drove [redacted] estimate down.

D2O Storage's engineering effort was originally scheduled for 11 months, and was supposed to be completed by July 2013. However, even today, engineering is not complete and is projecting to extend to a total duration of 29 months. The P&M team provided sporadic updates to the design milestones as they continued to be missed but failed to convey the potential consequence. In August 2013, P&M reported that CNO Milestone 73472M0015, "D2O Modifications –

Detailed Design Complete" was expected to miss its planned completion date of August 21, 2013 **by four months** though stated, "there is no impact to the critical path."[4] As of this same meeting, an action was recorded to "confirm the timing for integration" of the D2O Storage schedule into the master C&C Schedule, the follow-up to which indicated that the schedule would not be available for integration because "it falls short of our requirements for several parameters."

In September 2013, P&M reported in the Program Status Report that:

> Due to the change in design for the connection of the new tanks to the existing, significant additional design work is required. This change of design was required to address water hammer issues with the initial plans which could not be resolved without a significant change in design. A new underground tunnel connecting the two buildings will now be utilized to connect the two buildings.[5]

However, this "significant" design change was not highlighted as a major risk item in P&M's reporting, and P&M maintained the same EAC for D2O Storage despite having this information in hand. P&M also maintained that there was no impact to the critical path, even though P&M again admitted that the vendor had yet to produce a detailed schedule, which begs the question how could one arrive at such a conclusion regarding float without a reliable schedule.

P&M first reported a variance to the D2O Storage budget in October 2013, which coincided with months of mitigating adverse soil conditions and failing to meet the schedule for tie-ins for the TRF outage. Black & McDonald presented a high-level cost estimate that showed approximately $49M of increases in foundation work and engineering in October 2013, though this estimate was characterized as a work in progress. This estimate was increased by $5M in December 2013. P&M finally updated the D2O Storage EAC in the January 2014 DR Program Status Report from $95M to $122.7M, though simultaneously, P&M issued a report to the Nuclear Executive Committee ("NEC") showing a forecasted EAC of $152M. Thus, P&M's first reporting to senior management and other OPG stakeholders of any impact of the design changes that had been brewing for nearly two years was inconsistent at best.

In January 2014, Bill Robinson [redacted] to update its costs. [redacted] committed to an estimate of [redacted] (compared to its original contract of [redacted]), which with OPG's costs was ranged by P&M at a total of [redacted], including OPG contingency and financing costs. After coming on board, P&M's new VP required [redacted] to prepare a bottoms-up, high confidence schedule and budget based on the high level of engineering completion. [redacted]

Moreover, throughout 2011-13, P&M did not [redacted] update costs and provide visibility to the cost of these design changes as they were occurring; thus [redacted] P&M's management allowed [redacted]

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[4] DN Refurbishment Program Status Report Meeting, August 21, 2013

[5] DN Refurbishment Program Status Report Meeting, September 18, 2013

[redacted] and incorporate a flood of OPG stakeholder generated late design changes without adequate checks and balances or understanding of the magnitude of these changes.

As a direct consequence of P&M's failure to report these cost and schedule variances, senior management was deprived of the ability to:

- Stop the design changes that led to these increases;
- Stop the project entirely and resort to one of the other evaluated options;
- Identify and characterize the cost increases that are not related to Refurbishment and subject these changes to the same value-enhancing criteria as the remainder of the DR Project's work; and
- Mitigate the impact of the schedule delays and overruns.

Thus, the consequences to OPG are two projects that may cause external stakeholders to question OPG's management prudence.

e. Vendor Performance Issues

[redacted]

[redacted]

3. Current Schedule Status

P&M's effort to recover these projects began with finally getting the vendors to develop resource loaded, integrated Level 3 schedules, with focus on developing template schedules for D2O Storage and AHS. These schedules are portraying the following significant challenges:

- The AHS project is currently projecting about 3 months behind schedule which will delay the VBO outage. The schedule is currently being impacted by late design, with some twenty outstanding design changes that [redacted] needs to process. This late design could impact the schedule to September 2014 and beyond and frustrate both procurement and construction, which have essentially no float. Based on our review of this schedule, attempts to accelerate the work to recover this time could be ineffective. Instead, BMcD/Modus recommends P&M, in concert with the Station, look to: (1) eliminate these multiple design changes; and (2) rationalize and potentially reduce the time needed to commission the AHS. If these upfront and follow-on tasks can be reduced in duration, the project will regain some much needed time for construction.

- D2O Storage is more complicated. The combination of underground utilities and poor soil conditions, design changes, engineering delays and contractor performance has pushed D2O Storage to a projected completion of April 15, 2016, which has no float to OPG's need date. In analyzing the current status of the work, we have determined that: (1) while engineering has driven significant delays to date, accelerating its final completion will not result in improvement to the overall completion date; (2) the current March 2015 completion date for concrete and foundation work, including drilling and setting caissons, needs to be improved by as much as possible and ideally to complete prior to the onset of winter conditions in 2014; (3) the current duration for building on top of the completed foundations, including structural steel erection, building enclosure and mechanical piping, is a scant 5 ½ months and needs to be substantially improved. Based on this status, we recommend OPG examine: (1) value engineer the foundations and structural design, with the goal to eliminate as much of the building's complexity as possible – the office space and associated concrete structure may be over-designed based on non-Refurbishment requirements added during the attenuated design phase; (2) value engineer the building's piping design, which similarly increased due to ASIC and Station needs; (3) accelerate the caisson drilling so that rebar and foundation work can recover essential lost time.

OPG should also examine other options in light of the overruns on these projects, as less permanent solutions that were narrowly rejected in the upfront BCS may now prove to be more economical solutions. At a minimum, we recommend OPG examine and parse the costs associated with non-Refurbishment scope that was added by OPG's other stakeholders and consider capitalizing those costs separately from Refurbishment for purposes of future rate recovery. In any event, whichever course OPG choses with these buildings, it is imperative that it act quickly and definitively.

4. Corrective Actions by P&M Team

OPG senior management has taken definitive action to turn around the Campus Plan work, including bringing in new leadership for P&M and fostering greater integration between the P&M Campus Plan and DR Project work. The visibility of the issues P&M has encountered will help the BOP, Islanding and Services projects work more effectively with the ESMSA contractors.

P&M's and the DR Team's senior leadership are fostering a more collaborative and cooperative effort between OPG and the contractors, known as the "Collaborative Approach." Essential parts of this Collaborative Approach include:

- For the remaining Campus Plan Projects and BOP work, the OPG teams and the vendors working "shoulder-to-shoulder" to develop project scope basis and corresponding cost estimates. The ESMSA vendors have agreed to perform the work on an open-book, split cost basis. Relieving the ESMSA of the secondary compete bidding

DARLINGTON REFURBISHMENT BUSINESS CASE SUMMARY
APPENDIX C – SUMMARY OF ECONOMIC ASSESSMENT

1.1.2. Refurbishment Costs

In conjunction with the scope reviews and updates, cost estimates for the refurbishment scope of work have been updated as part of the Detailed Planning activities. As well, benchmarking has continued against publicly available costs of other on-going CANDU refurbishment projects at Pt. Lepreau and the Bruce 1 & 2 Units and lessons learned from these projects continue to be incorporated into the Darlington Refurbishment Program cost estimate.

A contract has been let for the main scope of the refurbishment outage, i.e. the re-tube and feeder replacement activities and definition phase work is well underway. The establishment of this contract has resulted in improving cost certainty on this major component of the scope. Other project bundles, such as Fuel Handling, Defueling, Turbine Generator and Steam Generator have either had contracts let or are in the final stages of evaluation and negotiation. Updated estimates of the OPG Program Management and Oversight function have also been completed.

Table C1 summarizes the Refurbishment Project costs which were utilized in the economic assessment. The overnight cost estimate for the known scope of work is [redacted] Billion. With [redacted] Billion of contingency added to bring the bottom line total to [redacted] Billion (2013$), this is considered a high confidence (90% confidence) estimate.

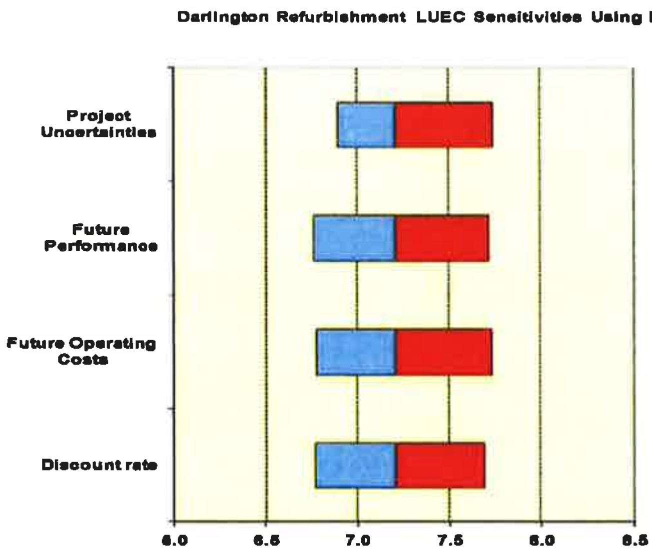
For the purposes of preparing sensitivity analyses, ranges were applied to the most likely estimates in each line item of the cost estimate.

Table C1: Refurbishment Project Costs Used in the Updated Economic Assessment

		Category of Work	Nov-13	Nov-12	Nov-11	Nov-09	Plan/ Plan 09 - 13	Description of Work
Project Estimate ($2013)	Direct Work	Major Contracts (RFR, FH, Defueling, SG, TG)	[redacted]					Vendor EPC (Engineering, Procurement, Construction) costs for major component work programs, including retube and feeder replacement, turbine generator upgrades and digital control system, Steam Generator primary side clean, and fuel handling equipment refurbishment
		Balance of Plant						Vendor EPC costs for refurbishment of balance of plant equipment including implementation of 3rd Emergency Power Generator and Containment Filtered Venting
		Islanding						Includes containment isolations (bulkheads), D20 management modifications and negative pressure containment
		Holt Road Improvements						Estimate from MTO Stand alone BCS to be provided to BoD
		System Shutdown						Includes In-Station Facilities
		Operations & Maintenance Support						Includes online, cyclical, project support, chemistry, radiation and return to service programs
		Waste Mgmt & Waste Containers						Tipping fee based on m3 Excludes storage building due to accounting determination
		New Fuel						Fuel replacement for each refurbished unit once returned to service
		Facilities and Infrastructure Projects						Facilities and infrastructure improvements to support refurbishment activities (i e Darlington Energy Complex, D2O Storage Facility) and extended station operations (i e Water and Sewer, electrical upgrades, Operations Support Building renovation)
		Total Direct Work						
		OPG Project Management and Support						
		Total Direct plus Indirect Work						
		Contingency and Management Reserve						
		Total Project Estimate						
		Capitalized Interest						
		Total Project Estimate Incl. Interest						
		Future Escalation						
		Total Project Estimate ($ of the year)						

DARLINGTON REFURBISHMENT BUSINESS CASE SUMMARY
APPENDIX C – SUMMARY OF ECONOMIC ASSESSMENT

Figure C5: Sensitivity Analysis – Darlington LUEC

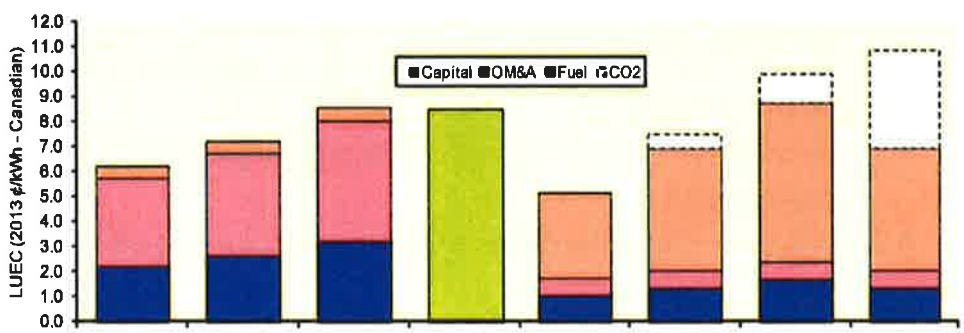


Assumptions	Lower	Median	Upper
Project Uncertainties			
Refurb Cost (2013$)	-10%	[redacted]	15%
Refurb Duration (months)	-2 mths	36 mths	+5 mths
Future Performance			
ACF (%)	-5%	88%	5%
Life of Refurb Units (yrs)	+2 yrs	30 yrs	-2 yrs
Future Operating Costs			
Base OM&A ($M)	-5%	270	10%
Outage OM&A ($M)	-10%	115	10%
Sustaining Projects ($M)	-10%	135	10%
Nuclear Support ($M)	-5%	215	15%
Corp Support Incr ($M)	-15%	235	10%
Fuel ($/MWh)	-15%	5	15%
Discount Rate	-1%	7%	+1%

2.3. Comparisons to Other Options

A significant input into the decision-making process on the economic viability of the Darlington Refurbishment is a comparison to the LUECs of other options competing with this project. Figure C6 presents such a comparison.

Figure C6: Levelized Unit Energy Costs for Darlington Refurbishment and Comparators



Assumptions:	Darlington Refurb			Bruce 1/2	New CCGT			
Scenarios	Low	Median	High	-	Low	Median	High	Carbon-free based on Median
Overnight capital (C$B)	[redacted]							
Overnight capital (C$/kW)								
Annual Fixed Operating Cost (C$M)	885	965	1,075	N/A	15	15	15	15
Annual Capacity Factor (%)	93%	88%	83%	85% (est.)	93%	88%	83%	88%
Gas Price (C$/mmBtu @ Henry Hub)					4	6	8	6
CO2 Offset Cost (C$/tonne)					0	15	30	100

PO # 10

4.4 Primary - Do the costs associated with the Niagara Tunnel Project that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?

4.5 Primary - Are the proposed test period in-service additions for the Niagara Tunnel Project reasonable?

Nuclear

4.6 Primary (reprioritized) - Do the costs associated with the nuclear projects that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?

4.7 Oral Hearing: Are the proposed nuclear capital expenditures and/or financial commitments reasonable?

4.8 Primary (reprioritized) - Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Project) appropriate?

4.9 Primary - Are the proposed test period in-service additions for the Darlington Refurbishment Project) appropriate?

4.10 Primary - Are the proposed test period capital expenditures associated with the Darlington Refurbishment Project reasonable?

4.11 Oral Hearing: Are the commercial and contracting strategies used in the Darlington Refurbishment Project reasonable?

4.12 Primary - Does OPG's nuclear refurbishment process align appropriately with the principles stated in the Government of Ontario's Long Term Energy Plan issued on December 2, 2013?

5. PRODUCTION FORECASTS

Regulated Hydroelectric

5.1 Secondary - Is the proposed regulated hydroelectric production forecast appropriate?

5.1(a) Primary - Could the storage of energy improve the efficiency of hydroelectric generating stations?

5.2 Primary (reprioritized) - Is the estimate of surplus baseload generation appropriate?

5.3 Secondary - Has the incentive mechanism encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices?

5.4 Primary - Is the proposed new incentive mechanism appropriate?

5.0 SCHEDULE

In June 2013, to provide a higher confidence in the refurbishment outcome, a revised planning scenario was proposed which eliminates the execution overlap between the first and second units. This decision does pose a risk to idle time on later units, and OPG is working on programs to increase its confidence to operate the units beyond their normal design life.

This planning scenario will be used to update the base case in the Business Case Summary to be updated in late 2013. Upon approval by OPG's Board of Directors, the overall timeline and funding release strategy will be updated.

6.0 CONTRACTING

As noted, the DRP is a multi-phase project made up of individual projects of various sizes. As part of the Definition Phase, OPG developed an overall Commercial Strategy and separate Contracting Strategies for all major project work packages (Attachment 6). The "Commercial Strategy" sets out an overall commercial framework with guiding principles for establishing and maintaining commercial relationships with third parties to support the DRP.

A "Contracting Strategy" is the means for successful implementation of the project delivery approach for the major project work packages making up the DRP. Each Contracting Strategy is free standing and takes into account factors such as the nature and scope of the work, the vendor marketplace, and any potential long term commercial arrangements. Each Contracting Strategy results in a recommendation on the most suitable sourcing approach, contract structure and pricing mechanism for that specific work package.

6.1 Commercial Strategy

The Commercial Strategy selected by OPG is a multi-prime contractor model in which there is more than one prime contractor working on the project. The owner has a separate contract with each prime contractor. A prime contractor is responsible for the completion of the work under its particular contract, but not for the entire project. The owner is the integrator between the prime contractors and is responsible for the entire project.

In examining the alternatives, OPG took into consideration lessons learned from other nuclear refurbishment projects such as the consequences of schedule slippage and replacement power where a lump sum turnkey agreement was used; and in another instance, a mid-project commercial strategy change (i.e. the abandonment of the project management model and the adoption of the multi-prime model).

Under the Multi-prime Contractor model, individual standalone contracting strategies are developed for each of the major projects (e.g. RFR, Fuel Handling, Turbine-Generator, Steam Generators, and Balance of Plant). The strategies identify the breakdown of work packages to be assigned to each contractor. This flexibility allows OPG to tailor the strategy to the nature and scope of work, the marketplace and post refurbishment arrangements. In section 6.2 below, the Contracting Strategy for each major project work package is described.

6.1.1 Independent Review of Commercial and Contracting Strategy

In September 2011, Concentric Energy Advisors Inc. (Concentric) was retained to review whether the commercial and the contracting strategies for the DRP were reasonable and prudent. In a series of opinions (Attachment 7) Concentric considered OPG's overall Commercial Strategy and the contracting strategies for RFR, Turbine Generator, Fuel Handling, Steam Generator and Balance of Plant work packages. Concentric provided an assessment based on document review and interviews with OPG personnel, who concluded that OPG's Commercial Strategy is appropriate and reasonable and meets the regulatory standard of prudence given the current status of the Project. Concentric also found that OPG's approach in engaging contractors for each of the work packages were reasonable and prudent in the context of the DRP and current market conditions for these services. Concentric has made a number of specific recommendations that OPG will incorporate in future work on the Project.

6.2 Contracts for Major Work Packages

6.2.1 Re-tube and Feeder Replacements

During these phases, the project team brings the project online and completes all of the recordkeeping associated with the project.

The initiation phase of the Project began in late 2007 with the preparation of a business case that evaluated, at a high level, the overall feasibility of completing the Project. In November 2009, the Project sought and received authorization from the Ontario Power Generation Board of Directors to proceed with the planning portion of the definition phase. In February 2010, the Ministry of Energy concurred with the Board of Directors' decision. To execute the work, Ontario Power Generation will retain multiple contractors for discrete portions of the Project work known as work packages. Consistent with this approach, Ontario Power Generation has proposed dividing the work into multiple major work packages, of which the Turbine Generators work package is one.

As part of that process, the Company is currently pursuing contracts with qualified vendors for two separate scopes of work related to the Turbine Generators work package. The first scope of work, for Engineering Services and Equipment Supply, has been negotiated on a single-source basis with Alstom, the Original Equipment Manufacturer ("OEM"). The remaining scope, which will primarily involve additional engineering and on-site construction, is being pursued through a bundled, reduced-scope Engineering Procurement and Construction ("EPC") arrangement sourced through a competitive process that began in May 2013. Throughout the balance of this phase of the Project, the Company and its vendors will complete planning and design for the Turbine Generators work packages, execute project agreements, and develop a release quality cost estimate, among many other activities.

II. SUMMARY OF CONCLUSIONS

As discussed below, Concentric concluded that, based on activities that have taken place between late 2009 and August 1, 2013, the commercial strategy Ontario Power Generation is employing for the Turbine Generators work package is appropriate and reasonable and meets the regulatory standard of prudence.

Concentric's opinion is not without certain caveats and limitations, which are discussed in the sections that follow. Similarly, the basis for our opinions are described throughout the remainder of this document.

III. STANDARD OF REVIEW

To conduct our review of the commercial strategy selected by Ontario Power Generation for the Turbine Generators work package, Concentric sought to answer three primary questions:

1) Is the commercial strategy selected by Ontario Power Generation for the Turbine Generators work package reasonable?

2) Is the Company executing that commercial strategy in a reasonable manner?

3) Do the selected commercial strategy and the execution of that strategy meet the regulatory standard of prudence?

To answer these questions, Concentric adopted a definition for the regulatory standard of prudence based on Concentric's work before state, provincial and federal energy regulators in both Canada and the United States. The definition utilized by Concentric is consistent with decisions rendered by the Ontario Superior Court of

- First, our review is limited to Ontario Power Generation's actions and documents prepared between late 2009 and [August 1, 2013].[7] Concentric did not review Ontario Power Generation's actions related to the Project prior to or after that time period.

- Next, Concentric did not independently verify the appropriateness, sufficiency, or correctness of the project schedules, cost estimates, scope, or, from an engineering perspective, the division of responsibilities. However, Concentric was informed of the processes used to develop these items, and we reviewed assessments from outside experts that were engaged by the Company specifically to evaluate whether the Project and commercial terms with key vendors are consistent with similar projects throughout the industry.

- Concentric evaluated the division of responsibilities between the two key vendors at a high level, but is not providing an opinion on the appropriateness of the division of those responsibilities from an engineering perspective. We understand that the OEM will provide Engineering Services and Equipment Supply, and that the scope of work to be completed by a separate vendor under the EPC contract will include the original scope of work with equipment and technical oversight work removed.

  Concentric's opinion does not consider whether this division of responsibilities is practicable from the perspective of vendors that may respond to the Request for Proposals ("RFP") for the construction-oriented balance of work. We do note, however, that the Company received multiple expressions of interest from potential third party vendors to work with the OEM on the Project.

- In addition, Concentric assumed Ontario Power Generation will retain adequately qualified personnel to complete the Project generally, and the Turbine Generators work package specifically. Those resources are critical to the success of the project, and may be sourced internally, hired directly, or engaged through contracts with third parties.

- Concentric did not perform a compliance audit to determine whether Ontario Power Generation and the Project were in compliance with Ontario Power Generation's internal policies, procedures, instructions and guidelines, or applicable provincial and federal regulations. Similarly, Concentric did not conduct a legal review of Ontario Power Generation's agreements or proposed agreements with any contractors. Notwithstanding that limitation, Concentric did review relevant Ontario Power Generation internal policies and procedures, and relevant provincial and federal laws and regulations when developing our opinion.

- Finally, Concentric's review is not an assessment of the Project's likelihood of success. Successful execution of the Project generally and the Turbine Generators work package specifically will require the efforts of many entities and individuals over many years, and the development and implementation of the Project's commercial strategies is only one contributor to project success.

[7] The beginning of the period Concentric reviewed is roughly concurrent with Ontario Power Generation's completion of the Economic Feasibility Assessment of Darlington Refurbishment dated November 13, 2009. However, portions of the operational experience material reviewed by Concentric were prepared prior to this time.

END OF LIFE TIMING - SCENARIOS									
Darlington Units	End of Life - Effective Full Power Hours (EFPH) (1)								
	187,000			210,000			235,000		
	EOL No Refurb	Start Refurb.	End Refurb.	EOL No Refurb	Start Refurb.	End Refurb.	EOL No Refurb	Start Refurb.	End Refurb.
2	**Q3-16**	Oct-16	Sep-19	**Q2-19**	Oct-16	Sep-19	**Q2-22(2)**	Oct-16	Sep-19
1	Q3-16	**Oct-19**	Sep-22	Q2-19	**Oct-19**	Sep-22	Q2-22	Oct-19	Sep-22
3	Q1-17	**Mar-21**	Feb-24	Q4-19	**Mar-21**	Feb-24	Q4-22	Mar-21	Feb-24
4	Q3-17	**Oct-22**	Sep-25	Q2-20	**Oct-22**	Sep-25	Q2-23	Oct-22	Sep-25

NOTES

1. The dates indictaed in the EOL columns are extrapolated or best efforts estimated estimated from the BCSs for project 62444 and project 80014.
Start Refurb, End Refurb dates are taken from Nov. 2013 BCS
Green means no risk to the Refurbishment start due to Fuel Channel EOL Limit if the CNSC approves the revised limit at the specified value.
Yellow **means fuel channel EOPL limit needs to be extended to the Quarter identified and beyond or unit has to be shut down earlier (**idle **time) to meet the revised schedule.**

generation option. As OPG has already implemented the accounting changes, SEC proposed a DRP Accounting Variance Account. Payments would be collected from ratepayers, but the equivalent of the proposed reduction in revenue requirement would accumulate in the account. If the DRP proceeds, ratepayers would be credited with the savings. OPG questioned whether SEC's proposed account could even be recognized for financial statement purposes as it would be a contingent asset, only realized if DRP did not proceed.

VECC noted that the impact of the DRP, with the CWIP in rate base removed, amounted to a credit to customers of $235.2 million of which $188.8 million is nuclear liability related. On the basis of the protection afforded OPG under the Ontario Nuclear Funds Agreement ("ONFA"), the nuclear liability deferral account and the ability to unwind the impact of depreciation rate changes, VECC submitted that the Board could approve OPG's DRP requests (with the exception of CWIP). VECC argued that if DRP does not proceed, the updated reference plan under ONFA and the operation of the nuclear liability deferral account will true up the impacts.

As noted above, OPG implemented the accounting impacts of the Darlington service life extension effective January 1, 2010. SEC and VECC argued that these changes were inappropriate. The parties argued that the changes had the effect of reducing the revenue requirement in 2010 by $64.2 million, and that this amount should be credited to ratepayers. SEC further added that the Board should declare OPG's 2010 rates interim, lest an argument of retroactivity impede implementation of the credit. OPG replied that the accounting changes with respect to ARO, ARC and Darlington life extension which took place on January 1, 2010 have been audited by external auditors. OPG characterized SEC's proposal as retroactive ratemaking.

OPG also argued that a complete reversal of these accounting adjustments would raise an issue of consistency with the Board's decision in EB-2007-0905 as it pertains to the Bruce facilities.

Board Findings

The Board agrees with OPG that section 6(2)4 of O. Reg. 53/05 applies to the DRP as it is designed to refurbish a generating facility to which O. Reg. 53/05 applies. All cost variances (both capital and operating expenses) will be captured in the account for later disposition. Therefore, the Board's mandate is to ensure that OPG recovers the costs of the DRP if the Board is satisfied that these costs were prudently incurred. However, in the Board's view this does not preclude the Board from assessing the reasonableness of the proposed expenditures before they are made. The Board agrees with OPG that the prudence review of those aspects of the work which are found to be reasonable in this proceeding will be limited to the differential between the proposed expenditures and the actual cost.

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

- whether the planned capital and OM&A spending on the DRP in 2011 and 2012 is reasonable;
- whether OPG's decision to reflect the planned extension of the end of life for Darlington for accounting purposes is reasonable; and
- whether CWIP should be allowed in rate base.

Approval of the expenditures for the test period should not be taken as an acceptance of the business case underlying the entire project. Once the DRP reaches the stage of having a release quality cost estimate the Board expects to examine the reasonableness of proceeding with the project. At that time, the Board may consider establishing a framework within which prudence could be examined should the project proceed forward. Other approval mechanisms, including some form of pre-approval of future expenses, may also be considered. The Board's findings in this proceeding are not determinative of the outcome of that review.

The Board expects OPG to file updated information on its progress for examination in the next proceeding.

The Board accepts OPG's evidence that its Board of Directors has given approval to proceed with the DRP. Of course, as it is a phased project, the question of whether to continue with the project or terminate it will be addressed at each Board of Director approval stage. It remains open to OPG to recommend to its Board that the project not be continued, and it remains open to the Board of Directors to halt the project.

OPG urged the Board to find that the Minister's letter concurring with the DRP means that the DRP is, by definition, in the public interest. The Board declines to make such a finding, but is also of the view that it does not need to make a finding that the project as a whole is in the public interest in order to grant the approvals sought by OPG in this application. The Board disagrees with GEC's position that public interest must be determined before a determination on the capital budget. For purposes of this Decision, the Board's focus is on the reasonableness of the test period expenditures, including a determination as to whether they are supported by the business case. The Board also observes that nuclear refurbishment is included in the Supply Mix Directive, which is not subject to the Board's approval.

A number of parties expressed concerns about the quality of the business case for the DRP. The Board shares their concerns about the likely overall costs of the project and the ability of OPG to keep the project in the $6 billion to $10 billion range currently forecast. Quite apart from whether OPG has improved its performance, the Board has concerns because no CANDU plant has yet been refurbished on budget. Despite these limitations, the Board finds that for the purposes of approving the spending in the test period, the business case is a reasonable underpinning, and the Board approves the OM&A spending as forecast. OPG did not seek specific approval of the capital expenditures, but it did request the inclusion of CWIP in rate base and that request is addressed below. The Board does not normally give approval to capital expenditures for projects which come into service after the test period except in the case of a leave to construct application. With respect to all other capital budgets in this case, the Board has limited itself to addressing the amounts for items entering into service in the test period. However, the Board finds the forecast DRP capital expenditures for the test period to be reasonable.

If the results of the definition phase demonstrate that the costs will rise significantly, the Board expects that OPG's Board will reassess the project at that time. The Board notes the high level of confidence expressed by OPG's witnesses in the costs presented despite OPG's history of cost over-runs and the current experience with the cost overruns of refurbishments at Point Lepreau and Bruce. If there are cost overruns with the DRP, the Board does not expect OPG to suggest that they could not have been foreseen at this stage. This factor may well be considered in any prudence review.

As the DRP is a multi-year project the Board expects that in future payments cases the business case will be updated as OPG seeks further approvals for the project. The Board will therefore not require any additional reporting as requested by SEC, nor will there be any caveats placed in advance on what might happen if OPG does not file an application for 2013. As indicated in the findings related to the Pickering B Continued Operations Project, the Board is concerned that ratepayers bear a particular risk in relation to these large nuclear projects, which have a history of going over budget. In examining the project going forward, the Board will be interested in examining whether any performance incentives might be appropriate within the parameters of O. Reg. 53/05 and the variance account.

The second major issue is whether the changes in rate base, return on rate base, depreciation expense, tax expense and Bruce lease net revenues that result from service life extension to 2051 are appropriate, from a regulatory perspective.

The Board accepts OPG's evidence that the restatement of the service life extension is in accordance with the decision of the company's Board of Directors to approve the DRP, with GAAP, and as far as it affects net revenue from the Bruce lease arrangements, in accordance with the Board's decision in the previous proceeding.

The only concern with extending the service life for regulatory purposes is what the future impacts would be if a later decision was made to not proceed with the DRP, and the end of life dates were changed to an earlier date. Some parties were concerned that there might have to be large rate increases to recoup the funds not collected during the test period. The Board agrees with VECC that the impact of any future restatement can be reasonably managed, given the protection afforded the company through the ONFA, the nuclear liability deferral account and the possibility of the unwinding of the impact of depreciation rate changes. If DRP does not proceed, the inclusion of DRP in the updated reference plan under ONFA, which is expected in 2011 for the next five-year period of 2012-2016, would result in financial impacts being captured in the nuclear liability deferral account.

The Board notes that by not filing a 2010 payments case, OPG benefited from the changes in the accounting treatment of the DRP in 2010, but ratepayers did not. OPG could have sought an adjustment to the Reference Plan as a result of the changes, and that would have ensured that the revenue requirement impacts would be captured in the variance account; it is unfortunate that OPG chose not to do so. However, the Board is not prepared to accede to SEC and VECC's request to, in effect, reverse the 2010 accounting changes relating to the DRP, or to credit ratepayers with the difference that resulted. The 2010 rate year is not the subject of this application. The Board is not prepared to reopen one element of the previous decision without reviewing the entirety of the 2010 rate year.

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Ontario

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OFFICE OF THE CHAIR

The Honourable Jake Epp
Chair
Ontario Power Generation
1900–700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Epp

I am writing in regards to the government's recently released Long-Term Energy Plan (LTEP) as it relates to Ontario Power Generation.

Atikokan Generating Station Biomass Conversion

On August 26th, 2010, I directed the Ontario Power Authority to negotiate an "Atikokan Biomass Energy Supply Agreement" (ABESA) with OPG for the output from the Atikokan Generating Station once it has been converted from coal to biomass. I stated that the conclusion of the ABESA was contingent on a direction to OPG overriding paragraph A5 of the Memorandum of Agreement between the Crown and OPG dated August 17, 2005. This paragraph precludes OPG from pursuing any non-hydroelectric renewable generation projects.

The LTEP restated the government's desire to have the Atikokan Generating Station operating on biomass by the end of 2013. I would like this letter to serve as sufficient direction to OPG to enter into the agreements necessary to achieve this goal.

Thunder Bay Generating Station Natural Gas Conversion

As stated in the LTEP, the government would like both units at the Thunder Bay Generating Station converted from coal to natural gas by the end of 2014. Due to the lead times involved in natural gas conversion, I would request that OPG continue with definition phase work on the construction of the required natural gas infrastructure in advance of any directive on a revenue agreement for the output from the plant. This would include proceeding with the public environmental assessment on the pipeline.

I expect that OPG will work with the IESO to manage outages at the northwest thermal stations to ensure that system reliability is maintained while adhering to the schedules specified in this letter.

.../cont'd

Nanticoke Generating Station Unit Closure

The LTEP also stated that Ontario will shut down two additional units at Nanticoke Generating Station before the end of 2011 as part of the government's continuing coal phase out strategy. I would like OPG to develop and implement a plan to place these units on stand-by in fall 2011 and have them shut down entirely by the end of 2011. Again, I expect that OPG will work closely with the IESO to manage the timing of these closures.

Nanticoke and Lambton Natural Gas Pipelines

Although the government has not yet made any decisions on the future of either the Lambton or Nanticoke Generating Stations after coal phase out, I would like OPG to continue with planning work on natural gas conversion in the event that converted station(s) are required for system reliability. This will include public consultations regarding pipeline routing and environmental reviews.

Refurbishment at the Darlington Nuclear Generating Station

The government is committed to continuing to use nuclear power to supply about 50 per cent of Ontario's energy supply. Achieving this goal will require the refurbishment of all existing units at OPG's Darlington Nuclear Generating Station. This refurbishment is key to the government's plan for modernizing the existing nuclear fleet. To this end, I encourage OPG to efficiently manage the refurbishment process in a transparent and cost-effective manner.

New Nuclear Construction

The LTEP restated the government's intention to construct about 2,000 MW of new nuclear power at the Darlington site. Due to the lead times involved in nuclear procurement and construction it is essential for OPG to continue with the environmental assessment and site licensing process currently underway to ensure that we are ready to construct the new units following selection of a preferred vendor.

I look forward to working closely with OPG as we phase out coal generation in Ontario, re-power some existing generating assets with clean fuels, and expand our supply of safe and reliable nuclear power. Thank you for your attention to these matters.

Sincerely,

Brad Duguid
Minister