EB-2013-0321

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

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

GEC CROSS EXAMINATION MATERIALS

OPG Panel 8 - DRP

Note: Additional materials will include:

Ex. JT3.17 still to be produced by OPG

Non-redacted, confidential versions of JT 2.2, 2.3 and 2.9

<u>Table 1 – DRP In-Service Amounts</u>

$ 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.

success. However, the first of the Campus Plan Projects was D2O Storage, which is as technically and logistically complex as virtually any work on the DR Project, and this project was unfortunately used as a pilot project.

The Refurbishment Project has, from the start, proceeded with its major EPC contracts using a more direct management approach which has been further strengthened by internalizing the early lessons from D2O Storage and AHS and by changes in the senior management team. Since the inception of our engagement in late February 2013, we have witnessed a number of changes by the DR Team that incorporated lessons learned, notably the changes to the method for scheduling the work via a fully integrated Level 3 schedule, increased focus on necessary scope through a robust process with multiple checks and vetting, and adhering to the gate process for budget approval with greater rigor.

Moreover, the EPC contracting method selected for Refurbishment's major scopes of work—the RFR/Containment Isolation, Turbine Generator and Steam Generator projects—has been managed differently and much more effectively than the pilot Campus Plan Projects. Because of their timing, the pre-requisite Campus Plan Projects provided the DR Team with an opportunity to test its new EPC model and draw experience for the much larger Refurbishment effort. Thus, the Campus Plan Projects were intended to be a source of lessons learned. The area in Refurbishment where the lessons learned from D2O Storage and AHS are most salient is the Balance of Plant work: here too, Refurbishment has made essential changes to the procurement method, scope identification and instituted greater collaboration at a much earlier stage than seen from the Campus Plan Projects.

b. Overall Cost Impact

A critical aspect of our 2Q 2014 Report's examination was to identify the extent to which the early problems with D2O Storage and AHS spread and otherwise impacted the Refurbishment Project. From a budget standpoint, while the DR Team is still examining the extent of the cost impacts from each of the Campus Plan Projects, it would appear that approximately 67% of the overall variance from the 4c Cost Estimate approved by the Board in 2013 resides with these two troubled projects. The following chart illustrates the current budget status for the Campus Plan Projects:

Bundle	Project	Release 4C estimate	Current Forecast*
F&IP (Campus Plan)***	D_2O Storage	$110M	$276M**
	OSB Refurbishment	$45M	$53M
	Auxiliary Heating Steam	$46M	$85M
	Water and Sewer	$46M	$58M
	DEC	$87M	$87M
	R&FR Annex	$32M	$41M
	RPO	$89M	$100M
	Electrical Power Distribution	$14M	$13M
	Other F&IP Projects	$83M	$111M
Subtotal		**$552M**	**$824M**

* Current forecast amounts provided by the DR Team.
** The D2O estimate is currently being challenged and confirmed. This is an interim estimate that may not be reflective of the final Estimate at Completion.
*** Does not include SIO Projects

It is important to note that we believe that the majority of the cost increases with D2O Storage and AHS are due to maturation of these projects' scope definition, scope management, unforeseen subsurface conditions or flawed estimates. In other words, the increased budgets are simply reflective of the true project costs had they been estimated properly at the outset. Moreover, we have no issues with the project delivery approach (multiple-prime EPC, target price). We have seen the multiple-prime EPC approach employed successfully on other projects, and it is appropriate for OPG to act as the construction manager and design authority for a refurbishment project on an operating plant. Additionally, target pricing in this context is appropriate—particularly prior to the completion of detailed engineering—a

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

2.0 Results

The LUEC was calculated using the above assumptions and alternative scenarios and sensitivity analyses were run on the low/high (pessimistic/optimistic) assumptions in order to assess the sensitivity of the results to the various input variables. These results are presented below.

2.1. Levelized Unit Energy Costs

The project's economics and the BCS have been updated based on the latest information. The updated analysis also indicates 70%- 90% confidence that the LUEC for Darlington Refurbishment will be in the range 7.6 ¢/kWh to 8.1 ¢/kWh (2013$) and very high confidence that the LUEC will be less than 8.7 ¢/kWh (2013$). Therefore, management continues to have high confidence that the LUEC of refurbishing and continuing to operate the Darlington units for a further 30 years, as shown in Figure C3, would be less than 8 ¢/kWh (2009$), as provided in November 2009, which is equivalent to 8.7¢/kWh (2013$)).

Figure C3: Levelized Unit Energy Cost Confidence Ranges

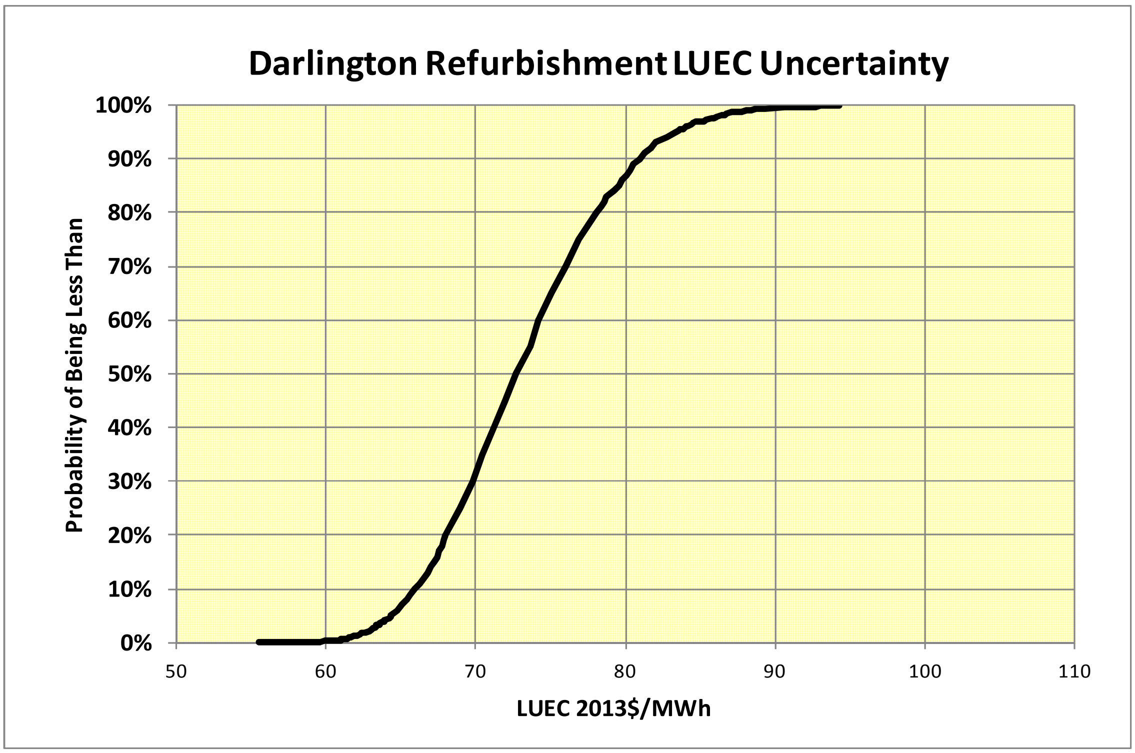


Figure C4 shows the percentage contribution of the major components which make up the DRP LUEC. These are: 1) Direct Station OM&A and Fuel costs; 2) Station Support provided by both Nuclear and Corporate Support groups; 3) the DRP itself, and; 4) fixed Corporate Overheads for pension and OPEB.

DARLINGTON REFURBISHMENT BUSINESS CASE SUMMARY

Alternative 3: Delay the Approval of continued work in the Definition Phase of the DRP by 1 or more years – NOT RECOMMENDED.

This alternative would result in a suspension of the Definition Phase work, including work on the required infrastructure to execute the program, and would likely result in increased costs to demobilize and remobilize the significant planning, engineering, project management and oversight organization which OPG has built up over the past several years. There is a risk of a loss of key resources to other projects, in particular, competing refurbishment projects on the Bruce units. The risk of "idle time" on all of the units increases relative to Alternative 2, but is decreased on Units 1, 3, and 4 relative to Alternative 1.

Economic analysis shows that this alternative is more costly to the Ontario system than the recommended alternative (Alt 1).

Alternative 4: Abandon the DRP and do not Plan to Refurbish Darlington – NOT RECOMMENDED

Refurbishment of the Darlington units is supported by the Ontario Power Authority's (OPA) IPSP I and is included in the Ontario Government's Long-Term Energy Plan (LTEP) (2010) and in the Supply Mix Directive (2011) issued by the Government to the OPA, and is expected to be included in the LTEP II plan to be released in the fall of 2013. Compared to CCGT options, which require a lower capital investment, the refurbishment of Darlington exposes OPG to significant risk exposure because of the high capital cost. However, CCGT options are more expensive on a life cycle basis than the Darlington Refurbishment Project at median gas price forecasts and assumed carbon taxes and have significantly higher exposure to the risk of fuel costs increases, during their operating lives.

Economic Assessment

An assessment has been done of the relative economics of Alternatives 1, 2 and 3 at different assumed lives of the fuel channels. This assessment is summarized in the comparative Net Present Value Table below. Positive numbers mean that the Alternative is more economical; negative numbers mean that the Alternative is worse. It should be noted that, should the targeted number of EFPH not be achieved, there are mitigating actions that could be taken to avoid idling the units prior to refurbishment, including adjusting the refurbishment schedule and/or performing selective maintenance or replacements of fuel channels to enable the units to continue to operate until their refurbishment outages.

Table 1: Relative Present Values of Schedule Alternatives for Darlington Refurbishment

Alternatives Compared	Operating Life Achieved (EFPH)			
	210,000	**217,000**	**225,000**	**235,000**
2016 Start with No Overlap of 1^{st} and 2^{nd} Units (Alt 1) vs. **2016** Start with 1^{st} and 2^{nd} Units Overlapped (Alt 2)	-755	-385	-155	+30
2016 Start with No Overlap of 1^{st} and 2^{nd} Units (Alt 1) vs. **2017** Start with 1^{st} and 2^{nd} Units Overlapped (Alt 3)	-15	145	160	345
2017 Start with 1^{st} and 2^{nd} Units Overlapped (Alt 3) vs. 2016 Start with 1^{st} and 2^{nd} Units Overlapped (Alt 2)	-715	-510	-295	-295

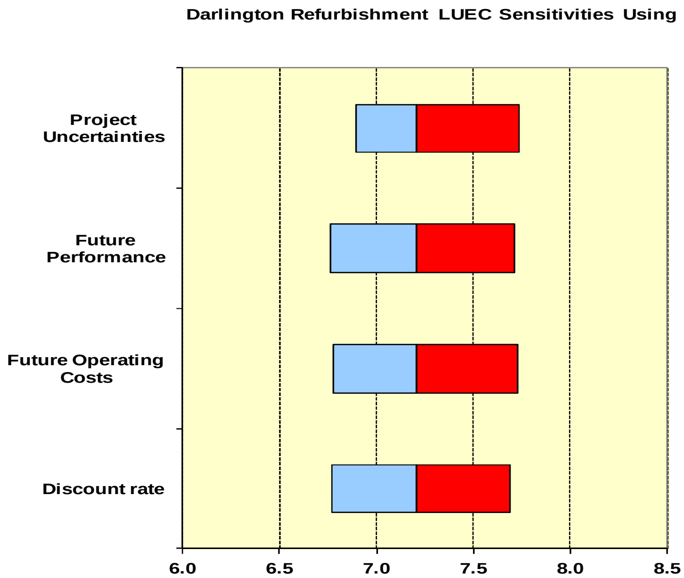
Conclusions:

1. Provided beyond 235,000 EFPH can be achieved, it is forecast to be slightly more beneficial to the Ontario system to remove the overlap of the first two units, than to retain the original over-lapped schedule.
2. In all except the 210,000 EFPH case, it is more beneficial to the Ontario system to start in 2016 with the overlap removed on the first two units, than to delay the entire refurbishment program by 1 year (and retain the overlap). At 210,000 EFPH, the two cases are virtually breakeven.

DARLINGTON REFURBISHMENT BUSINESS CASE SUMMARY

APPENDIX C – SUMMARY OF ECONOMIC ASSESSMENT

Figure C5: Sensitivity Analysis – Darlington LUEC

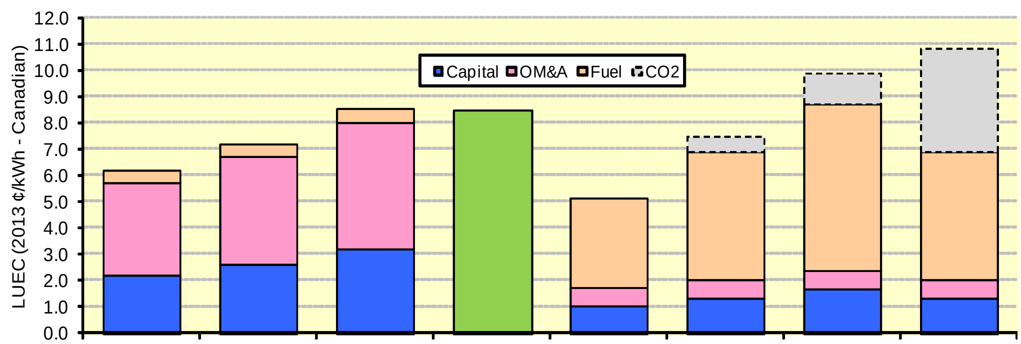


Assumptions	Lower	Median	Upper
Project Uncertainties			
Refurb Cost (2013$)	-10%	[redacted]	15%
Refurb Duration (months)	-2 mths	36 mths	+5 mths
Future Performance			
ACF (%)	-5%	88%	5%
Life of Refurb Units (yrs)	+2 yrs	30 yrs	-2 yrs
Future Operating Costs			
Base OM&A ($M)	-5%	270	10%
Outage OM&A ($M)	-10%	115	10%
Sustaining Projects ($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

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

The economics of refurbishing the Darlington Station are comparable with Combined Cycle Gas Turbines (CCGT) at a median long-term forecast of gas prices of approximately $6/mm BTU and assuming carbon prices of $15 - $30/tonne. At median gas prices and $15/tonne carbon prices, the LUEC for CCGT is estimated at 7.5¢/kWh (2013$), with the carbon pricing accounting for 0.6 ¢/kWh of that LUEC. At low long-term gas prices of about $4/mm BTU and zero carbon prices, the price of CCGT would be more favourable than the price for refurbishing the Darlington Station. It should be noted that the costs to make gas-fired generation carbon-free (i.e. carbon sequestration), is estimated to be the equivalent of a $100/tonne carbon price, which would add 4 ¢/kWh to the LUEC of a CCGT.

While CCGTs have shorter execution lead times, lower up-front investment, lower ongoing operations, maintenance and administrative costs, there are significant uncertainties with regards to future gas prices and the potential implementation of carbon prices. There are other considerations which contribute to and support the favourable economic assessment for refurbishing the Darlington Station. These include:

- The use of an existing generation site with a proven environmental record and a supportive host community avoids the additional costs to OPG (and ratepayers) of site selection, securing environmental approvals and development of host community support at an unproven green or brown field site. It also avoids the additional costs to ratepayers of establishing a new transmission infrastructure.
- The economic benefits of refurbishing the Darlington Station, in terms of direct, indirect and induced job creation, are anticipated to be greater than for CCGT. It is estimated that approximately 2,000 direct jobs are created during the Program Definition and Execution Phases. Continued Operation of the Darlington Station (post-refurbishment) will maintain the same level of employment as is currently associated with the Darlington Station for an additional 30 years. Economic impact studies indicate that post-refurbishment operations of the Darlington Station will result in approximately 5,700 resident jobs in Durham Region (direct, indirect and induced).

Management's assessment is that the refurbishment of the Darlington Station would also be competitive with the recently completed refurbishment of Bruce Units 1 and 2. Based on the Auditor General's 2007 assessment of the price being received by Bruce Power for the output of Bruce Units 1 and 2, management has estimated the LUEC for those units at approximately 8.5 ¢/kWh (2013$).

In summary, the Darlington Refurbishment Project's median confidence LUEC is approximately 7 – 7.5 ¢/kWh, which compares favourably with median confidence CCGT LUECs and with the estimated LUEC of Bruce Units 1 & 2.

3.0 Conclusions of Economic Assessment

The forecast LUEC for Darlington Refurbishment is competitive economically with other available generation options, including Combined Cycle Gas. There is merit to continuing the Definition Phase work and implementing the project based on current economic comparisons.

schedule methodology, project reporting and the BOP procurement method required changes, and the DR Team has made those changes. Further management challenges will present themselves as OPG recognizes that a multi-year megaproject is a different endeavor than the company's day-to-day business practices."

With respect to the DRP's cost range of $6 to $10 Billion, OPG believes that the cost variances from the Campus Plan Projects will be approximately $200 to $300 Million which equates to approximately 2% to 3% of the DRP's total $10 Billion high confidence estimate. Considering the level of contingency and management reserve within the high confidence estimate, OPG remains confident that the cost of the DRP will remain less than $10 Billion ($2013), excluding capitalized interest and future inflation.

With respect to incorporating lessons learned, BMcD/Modus noted that the DR Team has taken action on many of the items it raised. BMcD/Modus noted that OPG has either: already taken action on the recommendations as written by BMcD/Modus; or, has identified how the DR Team plans to address the recommendations in the future. BMcD/Modus expressed its satisfaction with the DR Team's response to its recommendations.

3.0 IN-SERVICE AMOUNTS

The Facilities and Infrastructure Projects, or Campus Plan Projects, consist of new facilities and infrastructure together with upgrades to existing facilities and infrastructure. They are required to directly support the current operation of Darlington, the refurbishment outages, and operation of the station after refurbishment. Safety Improvement Projects are modifications committed to in the DRP Environmental Assessment.

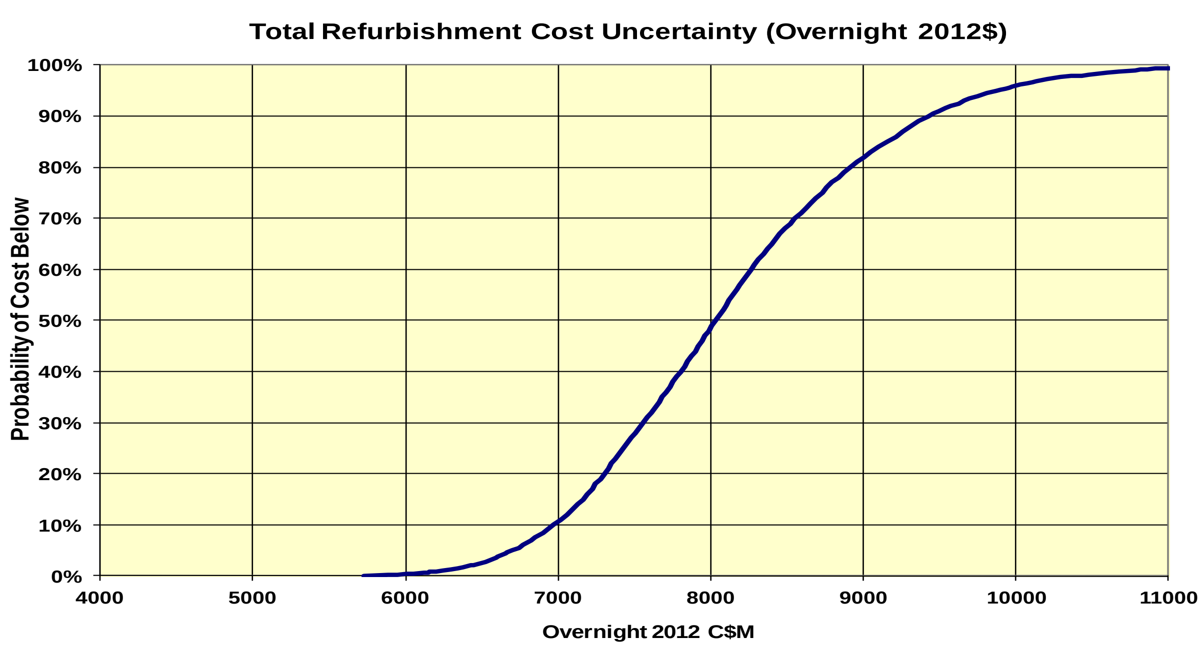
Table 1 provides a summary of the Facility and Infrastructure, safety improvement, and other station modification in-service amounts, for the 2014 to 2015 period. The table provides the amounts included in the original September 2013 filing in Ex. D2-2-1; the amounts discussed in the 1st Impact Statement filed in December 2013 in Ex. N1-1-1 and Ex. D2-2-1, Attachment 5; as well as the currently forecast amounts (Ex. D2-2-2).

4.0 ECONOMIC UPDATE

The Preliminary Planning Business Case, filed in EB-2010-0008, established with a very high confidence that the refurbishment of Darlington will result in a LUEC of less than 8¢/kWh (2009$) with a project estimate of less than $10.0B (2009$).

As a result of continued planning, a detailed understanding of scope, and a better understanding of the timing of cash flows, OPG updated its economic assessment of the project and presented it to OPG's Board of Directors in November 2012 (Attachment 5). OPG continues to have high confidence that the LUEC of refurbishing and continuing to operate the Darlington units for a further 30 years is less than 8.6¢/kWh (2012$), which is equivalent to 8¢/kWh (2009$). As shown in Figure 5, OPG continues to have a high confidence that the project cost estimate will be less than $10.8B (2012$) which is also equivalent to $10.0B (2009$). These costs are presented as overnight dollars and exclude interest and future escalation.

Figure 5: Darlington Refurbishment Project Cost Estimate



VERSION (select >90% confidence estimate)		Overnight $		Plus escalation		Plus escalation & interest		
		$B	cents/kWh	$B	cents/kWh	$B	cents/kWh	Notes:
Preliminary Business Planning Case (EB-2010-0008) [Preliminary Release Business Case (OPG Nov 2009)]	2009$	10.0	N/A	12.2	N/A	14.0	7.2	2
* Version referenced in EB-2013-0321 Exh D2-2-1 attachment 5 updated page 2	2009$	10.0	N/A	12.2	N/A	14.0	7.2	2
	2013$	10.8	N/A	N/A	N/A	N/A	N/A	3
Economic Assessment (OPG BoD Nov 2012) Recommendation for Submission to the BoD/OPG	2009$	10.0	N/A	N/A	N/A	N/A	N/A	4
	2010$	10.2	N/A	N/A	N/A	N/A	N/A	4
	2012$	10.8	N/A	12.1	N/A	13.9	8.1	5
Updated Business Case Summary (OPG BoD Nov 2013 & filed February 6, 2014)	2013$	10.0	N/A	11.3	N/A	12.9	8.2	6

*** Note : Quote from page 2. "In 2010 Management communicated that project would be less that $10B (2009$) which is equivalent to $10.8B in 2013$, excluding capitalized interest and escalation Quote from EB-2013-0321 Exh D2-2-1 attachment 5 updated page 2**

Notes:

1. Per response to Board Staff IR#31a), LUECs calculations include interest and escalation and fixed corporate overheads.
2. The numbers in OPG's Preliminary Business Case and the numbers referenced in EB-2013-0321 Ex D2-2-1 Att. 5, page 2 are the same. OPG publicly communicated the $10B (2009) high confidence estimate in Feb 2010.
3. OPG did not convert the $10B estimate at the time to 2013$. The $10.8B (2013$) shown is based on actual esclation rates for 2010 to 2012 and a forecast for 2013. The resultant LUEC would be the same as the LUEC in 2009$, with 4 years of escalation added.
4. For similar reasons as stated in note 2, in 2012, OPG did not calculate what the LUEC would have been in 2009$ and 2010$. This would simply be a de-escalation by 2 or 3 years of the LUEC
5. The overnight high confidence estimate shown in 2012$ is simply the escalated value of the 2009$ high confidence estimate of $10.0B (2009$), using actual and forecast CPI.
6. In its 2013 assessment, OPG changed its high confidence estimate from $10B (2009$) to $10B (2013$).

UNDERTAKING JT2.2

Undertaking

To provide additional information with respect to Environmental Defence interrogatory 11, issue 4.12, as set out in Mr. Elson's letter.

Response

a) The table below provides the requested break-out based on the amounts included in Exhibit D2-2-1, Attachment 5 for OPG's high confidence estimate (excluding interest and escalation) in 2013 and 2014 dollars.

$M		2013$	2014$
RFR	OPG Project Management	690	704
	Contractor Cost	[redacted]	
	Contingency		
Fuel Handling	OPG Project Management	83	85
	Contractor Cost	[redacted]	
	Contingency		
Steam Generators	OPG Project Management	63	64
	Contractor Cost	[redacted]	
	Contingency		
Turbine Generator	OPG Project Management	195	199
	Contractor Cost	[redacted]	
	Contingency		
Balance of Plant	OPG Project Management	216	220
	Contractor Cost	[redacted]	
	Contingency		
Other Costs	Islanding		
	System Shutdown		
	Operations & Maintenance Support	863	880
	Facilities & Infrastructure	560	571
	Waste Management	10	10
	New Fuel	132	135
	Insurance	114	116
	Regulatory, i.e. ISR, EA, IIP	80	82
	Licensing (CNSC Fees)	73	74
	Contingency	[redacted]	
	Retube Waste Containers (Provision)	220	224
	Management Reserve	828	845
		$10,000	$10,200

Notes:

1. 2013$ estimate based on Exhibit D2-2-1, Attachment 5
2. 2014$ assumed 2% inflation
3. OPG Project Management includes both Program and Project level

b) At a 50% cost overrun, applied to the selected projects, and through the application of the contract model used in each of the contracts, the estimated point-estimate for the DRP, is less than $10.0 billion due to contingency and management reserve contained within OPG's high confidence estimate. At a 100% cost overrun, the project related contingency and management reserve are exhausted resulting in a projected cost overrun of $200 million above OPG's high confidence estimate. Note that for all scenarios, OPG maintains approximately [redacted] in Program level contingency (as noted in note 3 of Part C) of IR ED-011).

c) Cost overrun scenarios including interest and escalation are provided below.

	Total DRP Cost			Total LUEC (1)	
	2013$B	2014$B	Incl. Interest & Esc.($B)	2013$ ¢/kWh	2014$ ¢/kWh
50%	10.0	10.2	12.9	7.8	7.9
100%	10.2	10.4	13.1	7.9	8.0
150%	11.1	11.3	14.3	8.1	8.2
200%	12.1	12.3	15.5	8.4	8.5
250%	13.1	13.3	16.8	8.7	8.9

Notes:

1. LUEC excludes fixed Corporate Overheads for Pension and Other Post Employment Benefits, base estimate is 7.8 ¢/kWh (2013$) or 7.9 ¢/kWh (2014$).

- In respect of the Darlington Refurbishment Project ("DRP") OPG seeks the following as described in Ex. D2-2-1:
  - 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 $6.6M in 2014 and $18.2M in 2015 (Ex. F2-7-1, Ex. N2-1-1);
  - 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 of $5.7M.

- An order from the OEB declaring OPG's current payment amounts for previously regulated hydroelectric and nuclear facilities interim as of January 1, 2014, if the order or orders approving the payment amounts are not implemented by January 1, 2014.

- An order from the OEB declaring OPG's current payment amounts for the newly regulated hydroelectric facilities interim as of July 1, 2014, if the order or orders approving the payment amounts are not implemented by July 1, 2014.

provide a strong incentive to drive the recovery process. There are many uncertainties surrounding the prediction of future replacement power costs, such as the availability of alternative means of producing power indigenously, the cost of outside purchases, available surplus capacity, etc.

Because of the high degree of uncertainty associated with the study as a whole, a very simplistic model for assessing replacement power cost was chosen. The objective was to represent the major factors affecting cost whilst avoiding the complexities of a sophisticated cost model.

5.4.2 Model Description

The model used is based upon the information contained in Reference 10, supplemented by the following assumptions:

(a) The replacement power cost includes a benefit from deferred nuclear fuel costs.

(b) The loss on one unit can be replaced by existing coal-generated capacity.

(c) The loss of four units can be replaced 50 percent by coal and 50 percent by externally purchased power.

(d) There is a transitional period during the first six months of a four unit outage where the power is replaced by running down existing coal stocks.

(e) There is a transitional period after about three years of a four unit outage where previously-mothballed capacity can be brought into use.

The nominal cost of a one year outage of four units is 850 M$ in 1985 dollars. This value is expected to be approximately constant over the life of the station and represents about 18 M$ per unit per month. The cost of purchased power is expected to be about twice that of internal coal generation, so the replacement power cost for a single unit is about 12 M$ per month.

To allow for phase-in and phase-out of alternative sources of replacement power as described above, the cost model shown in Figure 13.5-7 is proposed. This leads to a cumulative outage cost curve as shown in Figure 13.5-8.

6.0 RESULTS

6.1 Numerical Estimates of Economic Consequences

Summaries of the task analysis results described in Subsection 5.2 are given in Table 13.6-1. Table 13.6-2 gives the final estimates of economic consequence for each FDC. The columns headed "4-unit" refer to the durations and costs associated with that period when all four units are out of service. "Additional 1-Unit" refers to that period when all but the damaged reactor have been returned to service.

6.2 Discussion of Uncertainties

6.2.1 General Comments

It is readily acknowledged that, in a study of the nature of economic consequence assessment, individual judgement has a very large role to play. In such circumstances, uncertainty arises conceptually from two distinct sources; (a) whether the judgements and associated assumptions necessary to the completion of the study are correct, and (b) the uncertainty associated with the numerical evaluations based on the judgements.

The quantification of uncertainty carried out for this study is based only on the contribution from (b) above. The network of tasks, the order in which they are carried out and many of the detailed radiological and technical assumptions are treated as fixed. As has been discussed in Section 2.0, the scope of the study has been limited to omit a number of potentially significant, though essentially uncontrollable, factors which could have far-reaching implications to any accident recovery. In general, it is felt that the radiological assumptions used tend to be conservative, whilst many of the overall study limitations are likely to be optimistic with respect to absolute cost.

It is recommended that the results of the study be treated first and foremost as a measure of relative economic consequence. Any use of the results in an absolute application should clearly acknowledge the limitations of the study. A discussion of the numerical estimates of uncertainty is contained in the subsection below.

6.2.2 Cost and Duration Estimates

There are essentially three different types of activity in the recovery network; limits on accessibility due to radiation levels, acquisition of specialized equipment and engineering tasks. The approach to quantifying uncertainty differs with task type.

Each FDC has two associated source terms which express uncertainty related to the radiological consequences of each category. No additional allowance for uncertainty has been made on calculating detailed radiological parameters (e.g., dose rates, contamination levels) from the basic source term data. In assessing potential delays caused by ambient dose rates, the uncertainty has been assessed by calculating dose rates against time for both source terms and comparing the results with a single acceptability criterion.

For the other task types, it is first necessary to determine whether the task is required for each FDC. The requirement is usually determined by the magnitude of the radiological release inside containment and other

Table 13.6-1

Numerical Estimates of Capital Costs and Outage Durations

FDC	Unadjusted Capital Cost* (M$) BE	(PM)	Outage Duration (Months) 4 - Unit BE	(PM)	Additional 1 - Unit BE	(PM)
1	160	(250)	45	(72)	65	(126)
2	160	(250)	37	(61)	64	(127)
3	90	(150)	24	(46)	26	(39)
4	90	(150)	24	(43)	21	(39)
5	80	(130)	21	(38)	9	(17)
6	16	(35)	17	(31)	0	(0)
7	16	(35)	6.5	(19.5)	3	(7)
8	1	(2)	1.5	(7.5)	0	(0)
9	12	(20)	4	(7.5)	1	(1.5)

* Unadjusted sum of capital cost components from Subsection 5.2., rounded.

Table 13.6-3

Unit Economic Risk Estimates

FDC #	Category Description	Mean Frequency (per reactor-yr)	UF*	Mean Consequence (M$)	UF	Mean Risk (M$/reactor-yr)
1	Fuel cooling lost within 200 s of reactor trip	2×10^{-6}	5	3700	2	.01
2	Fuel cooling lost between 200 s and 1 hour after reactor trip	8×10^{-5}	5	3400	2	.3
3	Fuel cooling lost > 1 hour after reactor trip	5×10^{-4}	4	2000	2	1.0
4	Large LOCA, early stagnation	3×10^{-5}	10	2000	2	.06
5	Large LOCA, delayed stagnation	1×10^{-4}	10	1600	2	.2
6	Single channel event, containment overpressure	2×10^{-3}	8	1100	2	2.2
7	Single channel event, no containment overpressure	3×10^{-3}	5	465	3	1.1
8	Loss of cooling to fuel in a fuelling machine	2×10^{-3}	10	75	5	.2
9	LOCA, no fuel failures	2.3×10^{-2}	3	230	2	5.2

* UF = Uncertainty factor

Total Quantified Risk 10 (UF=3)

ONTARIO POWER GENERATION

700 University Avenue Toronto, ON M5G 1X6

OPG Confidential

June 26, 2012

File No: 08502-12-21 T6

Shawn Patrick Stensil
Energy Campaigner
Greenpeace Canada
33 Cecil Street
Toronto ON M5T 1N1

Dear Mr. Stensil:

Request for Access to Information - Reference Number: 12-21

I refer to your request for access to information, received under the *Freedom of Information and Protection of Privacy Act* (FIPPA), on May 28, 2012.

The following record has been located in response to your request:

- Summary Spreadsheet for the calculation of the Levelized Unit Energy Costs (LUEC) for the Darlington Refurbishment Project.

Partial access is granted to the record, which has been severed in accordance with section 18(1)(a) and (c) of FIPPA as it contains financial information which, if disclosed, could prejudice the economic interests of OPG.

The person responsible for making the decision regarding access is Catriona King, VP, Corporate Secretary. You have the right to request a review of this decision by contacting the Information and Privacy Commissioner, within 30 days of receiving this letter, at the following address:

Information and Privacy Commissioner/Ontario
1400 - 2 Bloor Street East
Toronto ON M4W 1A8

If you wish to appeal this decision, please provide the Information and Privacy Commissioner's Office with: 1) a copy of this decision letter; 2) a copy of the original request for information which you sent to OPG; and 3) the appeal fee.

The appeal fee $25.00 and should be in the form of a cheque or money order, made payable to the Minister of Finance.

Sincerely,

R.C. Watson

Rosemary C. Watson, CRM
Manager, Corporate Records & Freedom of Information
H19 H10
Tel: 416-592-4309 Tol: 1-877-592-2555 Fax: 416-592-3621
E-mail: rosemary.watson@opg.com

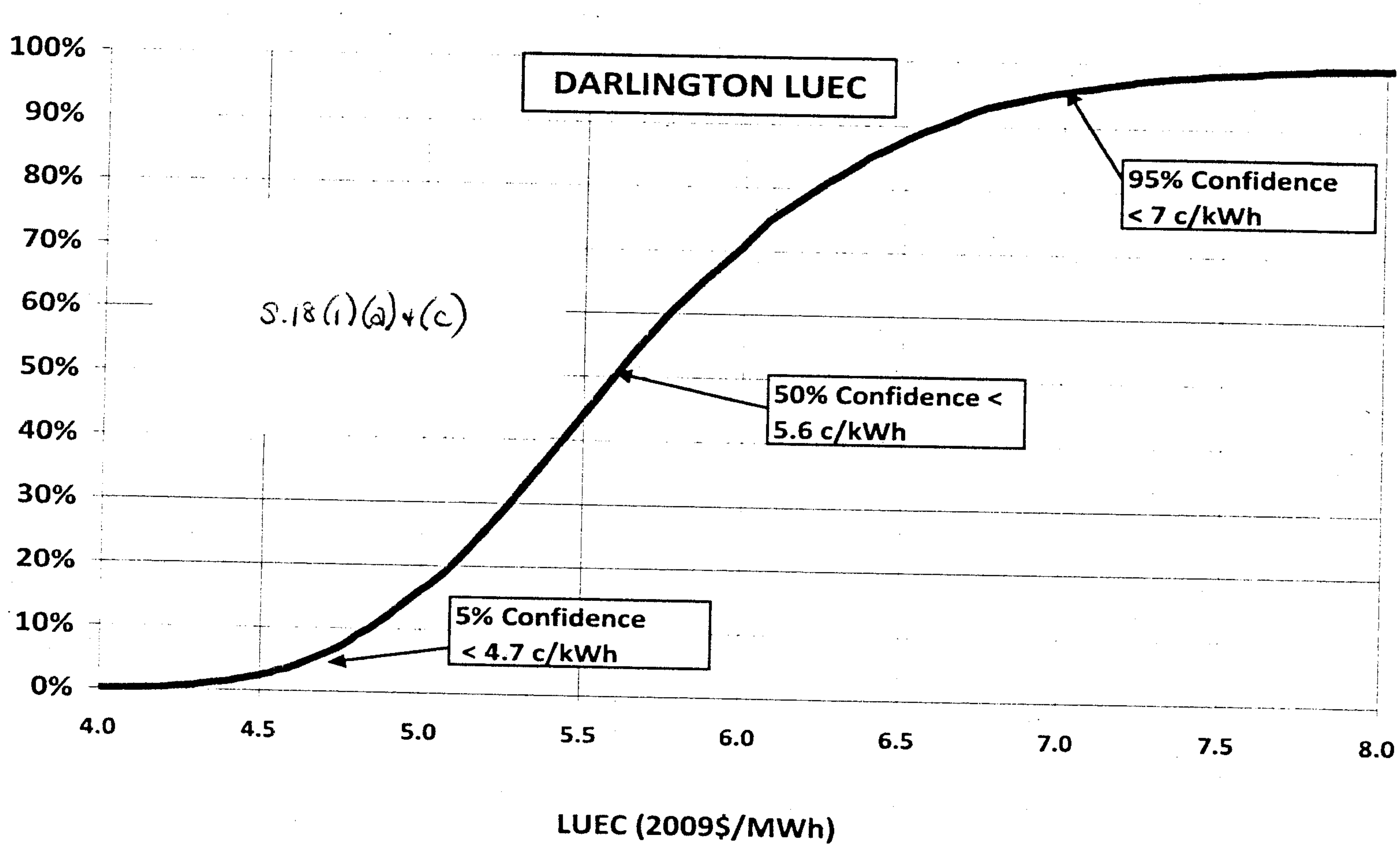
Enc

Darlington Refurbishment
Levelized Unit Energy Costs

ONTARIOPOWER GENERATION

- ❑ The analysis indicates a LUEC for Darlington of < 7 ¢kWh (2009$); management is <u>very confident</u> that the LUEC will be < 8 ¢kWh (2009$); on an incremental basis.
- ❑

s.18(1)(a)+(c)



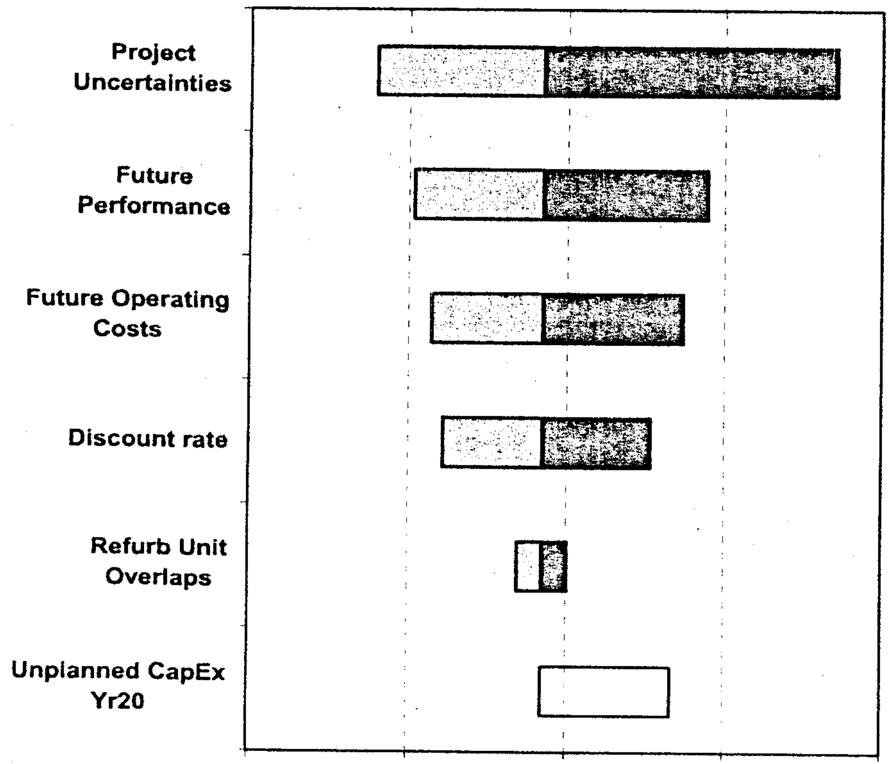
Sensitivity of LUEC to Input Variables & Potential Scope Changes

ONTARIOPOWER GENERATION

S.18(1)(a)+(c)

- LUEC is very sensitive to refurbishment project costs and duration.
- LUEC is also quite sensitive to future performance (Life and Annual Capacity Factor assumptions and to future operating costs (Direct Station and Nuclear & Corporate Support).
- If Steam Generators needed to be replaced it would add approx. ½ ¢kWh to the LUEC.

Darlington Life Extension
LUEC Sensitivities - ¢/kWh (2009$)



Assumptions	Lower	Base	Upper
Project Uncertainties			
Refurb Cost (2009$)	-15%		20%
Refurb Duration (months)	-6 mths		+12 mths
Future Performance			
ACF (%)	-5%	87%	5%
Life of Refurb Units (yrs)	+5 yrs	30 yrs	-5 yrs
Future Operating Costs			
Base OM&A ($M)	-5%	295	5%
Outage OM&A ($M)	-5%	95	10%
Sustaining Projects ($M)	-20%	100	20%
Nuclear Support ($M)	-5%	150	15%
Corporate Support ($M)	-10%	40	15%
Fuel ($/MWh)	-30%	5	30%
Discount Rate	-1%	7%	+1%
Refurb Unit Overlaps	+4 mths	19/16 mths	-4 mths
Unplanned CapEx Yr20			$1B/unit

S.18(1)(a)+(c)

Board Staff Interrogatory #058

Ref: Exh D2-1-2 and Updated D2-2-1 Attachment 5, Long-Term Energy Plan (December 2, 2013)

Issue Number: 4.12
Issue: 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?

Interrogatory

On December 2, 2013 the Ministry of Energy released the Long Term Energy Plan ("LTEP") for the Province of Ontario. The LTEP noted that:

> 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.

On December 5, 2013 OPG filed an update to its evidence, including OPG's 2014-2016 Business Plan (portions redacted) which was presented to its Board of Directors on November 14, 2013. On February 6, 2014 OPG filed an updated DRP Business Case Summary.

a) Is the 2014-2016 Business Plan consistent with all of the principles set out in the LTEP?
    i. If so, please demonstrate how the Business Plan puts each of the principles into action.
    ii. If not, please explain why OPG did not reflect these principles in the Business Plan.

b) Does the updated DRP Business Case Summary, including scope, cost schedule and project management approach, conform to the principles set out in the LTEP?
    i. If so, please demonstrate how the Business Plan puts each of the principles into action.
    ii. If not, please explain why OPG did not reflect these principles in the Updated Business Case Summary.

c) Please prepare a LUEC calculation which reflects the following scenario: at the completion of the refurbishment of Unit 2, actual refurbishment costs for Unit 2 are $0.7B in excess of budget. As a result, it is decided to cancel the refurbishment of Units 1, 3 and 4. What would the LUEC be for the production for a refurbished Unit 2 (i.e. all DRP costs recovered through only Unit 2 production)?

Response:

a) Although the Business Plan was issued prior to the Long Term Energy Plan ("LTEP"), OPG has assessed its submission against the principles identified in the LTEP and provides the following summary which illustrates the consistency of its plans with the LTEP. In relation to each of the LTEP principles, OPG has taken the following steps:

1. Minimize commercial risk on the part of ratepayers and government

- Locking down project scope well in advance of starting construction;
- Fully developing engineering and planning of the work so that it is 100% complete prior to the start of construction;
- Building a full-scale mock-up of the DNGS reactor and vault that will be used for training and proving the tools needed for the removal and replacement of the reactor components;
- Developing a release quality estimate ("RQE") in phases that incorporates a high-confidence budget and schedule for the work;
- "Unlapping" Unit 2 from the subsequent units so that the focus can be on the planning and construction of a single unit and so that OPG can gain from the lessons learned in completing the work;
- Utilizing target price contracts for the execution phase that is based on developing cooperation, transparency, and risk sharing with key vendors;
- Utilizing fixed price contracts for certain execution phase scope that is well defined and where risk transfer to a third party is appropriate;
- Negotiating various off-ramps and stages into contracts; and
- Establishing a robust risk management process to directly identify and administer commercial risks.

2. Mitigate reliability risks by developing contingency plans that include alternative supply options if contract and other objectives are at risk of non-fulfillment

- OPG's decision to "unlap" Unit 2 from the other units' refurbishments, which predated the LTEP, was intended to mitigate performance risk and to allow the DRP team to focus on one unit's refurbishment at a time. If the first unit is not successful, off-ramps are in place; the second unit refurbishment will not commence until the first unit is successfully returned to service.
- Risk assessment and appropriate contingency plans/back-out plans for each execution work package will be developed and included in the Release Quality Estimate.
- OPG's investment in the reactor mock-up will be used to perform full integration and commission testing of tools needed for refurbishment; lessons will be learned on the mock-up, not on the unit. The results of the mock-up testing will be incorporated into

the tooling performance guarantee, which sets the target schedule and price, with the R&FR vendor

3. Entrench appropriate and realistic off-ramps and scoping

- OPG has engaged in a deliberate process with numerous off-ramps for the definition phase including Board of Directors oversight and annual releases of funds.
- Each contract has off-ramp provisions allowing OPG to terminate, with or without cause; OPG would be accountable to reimburse vendor for any reasonably incurred costs only.
- Scope review process in place to minimize scope of work performed in Refurbishment period to things that must be done to extend life or can only be done in drained/defueled state.
- OPG has fully examined the scope of the Unit 2 refurbishment project and optimized the work based on OPG's regulatory commitments and/or on an analysis of the best time to perform the work.

4. Hold Private sector operator accountable to the nuclear refurbishment schedule and price

- For OPG, please see item 5.

5. Require OPG to hold its contractors accountable to the nuclear refurbishment schedule and price

- OPG, in implementing all of its contracts, is highly focussed on achieving value for money; there are incentives and/or disincentives related to achieving the cost and schedule set out in the contracts.
- Contracts with major vendors are being developed and vetted utilizing a deliberate, staged and gated process with requirements for budget, schedule, scope, and risk identification at each gate.
- Contracts have specific negotiated incentives and disincentives that are calculated toward promoting the contractor's (and OPG's) responsible management of the work.
- OPG is implementing a detailed, integrated Level 3 schedule that will encompass all of the contractors' and OPG's work, as well as a rolled-up Level 2 Control and Coordination Schedule that is used as a higher level interfacing tool.
- OPG has implemented cost control systems that are geared toward holding contractors accountable. These systems include earned value and budget controls through the gate process.
- OPG performs analysis of all pricing and check estimates for contractors' work. These estimates are provided by an independent vendor with experience in the industry.
- OPG's senior management has established separate regular steering committees with each of the major vendors' executives which provide senior level leadership with a forum to discuss progress, potential and real issues impacting performance and commercial issues.

6. **Make site, project management, regulatory requirements and supply chain considerations, and cost and risk containment, the primary factors in developing the implementation plan.**
    - OPG's plan for the RQE assumes that all of the factors listed will be fully considered, planned, and budgeted in advance of execution of the work.
    - Taking lessons from Pickering A, the DRP team has committed to completing the identification of all regulatory requirements well in advance of final design and construction.
    - OPG has committed to the completion of the design and proving of the Retube and Feeder Replacement tools and completing procurement of all long lead materials one full year prior to the start of the first unit refurbishment.
    - OPG has implemented, in accordance with Project Management Institute standards and Association for Advancement of Cost Engineering ("AACE") best practices, project controls and risk management programs and will continue to refine these tools as the outage nears.
    - OPG has retained external oversight and engaged other corporate functions in providing input and assurance that the DRP team is meeting its commitments.

7. **Take smaller initial steps to ensure there is opportunity to incorporate lessons learned from refurbishment including collaboration by operators.**
    - To fully incorporate lessons learned from the refurbishment of the first unit (Unit 2), the start of refurbishment work on the second unit (Unit 1) has been delayed until the completion of the first unit.
    - OPG has filled key positions in its project management team with individuals with direct experience of prior CANDU refurbishments.
    - OPG has contracted with SNC/Aecon, whose subsidiary CANDU Energy (formerly AECL) has been associated with each of the prior refurbishments.
    - OPG and its contractors are studying lessons learned and OPEX from those prior projects and incorporating those into the DRP.
    - OPG routinely collaborates with other CANDU operators directly and/or through the CANDU Owner's Group. OPG has initiated further discussions with Bruce Power to determine additional areas for collaboration.

b) Please see response to item a)

c) While OPG believes that the scenario posed in this interrogatory to be highly unlikely, OPG has done a LUEC calculation which adds $0.7B to the amount OPG currently forecasts would be placed in-service at the completion of the Unit 2 refurbishment outage, and also eliminated further expenditures on Units 1, 3 and 4.

In developing this estimate, OPG has assumed no cost mitigation of the refurbishment project if it became evident that only Unit 2 would be completed. OPG has also utilized a range of assumptions about the costs of operations and support for a single unit in the post-refurbishment period. OPG would expect that losses of economies of scale would result in the operation and support costs of one unit to be more than one-fourth of the operating and support costs of the 4-unit Darlington Station. OPG has also not included in the calculation any energy and costs of operating the remaining 3 units to the normal ends of their current (pre-refurbishment) lives.

The resultant LUEC ranges estimated for Unit 2 production only is in the order of 11 – 15 cents per kWh (2013$) over the life of Unit 2.

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

3

A Reliable and Clean Supply

While Conservation First is an important element of the LTEP, a clean, reliable and affordable supply of electricity also requires a diversity of generation types. Ontario will continue to develop new sources of supply to ensure that we reach these goals.

Nuclear

Ontario has made important investments in nuclear generation. The Canadian Manufacturers and Exporters reports that 15,600 people are employed in the operation and support of nuclear plants in Ontario, and 9,000 more would be employed for the refurbishment of the Ontario plants, for a total employment of approximately 25,000 people during the refurbishment period. The Organization of Canadian Nuclear Industries reports that an additional 30,000 people are employed in the nuclear manufacturing, engineering, construction and consulting, fuel fabrication, research and development, and medical isotopes sectors, in support of domestic and offshore nuclear projects.

The industry has been successful in exporting Canadian technology around the world to countries including Argentina, South Korea, China, Romania and India. International opportunities to use the nuclear expertise based in Ontario will continue to be explored.

Nuclear power is also part of Canada's science and innovation advantage, involving more than 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.

Generation has divided the work into multiple major work packages, of which Retube & Feeder Replacement is one.

Ontario Power Generation's selection of the multi-prime strategy was based on the recognition that alternative models have not been successful, and that there is a reasonable need to retain control of, and project management responsibility for, the Project. Specifically, Ontario Power Generation will retain control over deliverables, work processes, the scope of work, and the ultimate design of station modifications and replacements. Ontario Power Generation will also retain responsibility for planning and permitting, coordinating the interfaces between each of the prime vendors selected to complete the work packages, and overseeing the Project's multiple prime contractors. Finally, Ontario Power Generation will be responsible for vendor claims for scope changes, owner-caused delays and vendor-caused delays that affect other vendors (setting aside the Company's recourse to the vendor causing the delay). Importantly, the multi-prime strategy will provide Ontario Power Generation with additional flexibility to transfer work between major vendors if such a transfer promotes efficiency and value for money.

By using this model, Ontario Power Generation is accepting the challenge of managing each of the prime vendors and ensuring that each vendor is able to complete its work according to its plan. Given the complexity of the Project and the limited working space within the Darlington site, Ontario Power Generation's coordination of the various work tasks will require extensive planning to prevent claims of delay or increased costs caused by Ontario Power Generation's failure to adequately plan and coordinate the work or interference from another vendor.

C. CONCENTRIC'S OPINION OF THE OVERALL PROJECT COMMERCIAL STRATEGY

Concentric believes Ontario Power Generation has acted prudently in selecting the multi-prime contractor model strategy. Ontario Power Generation's selection of this commercial strategy appropriately and reasonably considered the operational experiences of refurbishment projects at the Bruce A and Point Lepreau refurbishment projects, and the restart of Pickering A. This model provides Ontario Power Generation with the necessary control over the design and planning of the Project and allows Ontario Power Generation to utilize the expertise of specialty vendors in a cost effective manner. We note that a variation of this model is being used to successfully deploy new nuclear facilities in China. In that model, a Chinese state-owned entity is sponsoring nuclear construction projects at Sanmen and Haiying. A local construction company is being utilized to construct the projects while a consortium of the Shaw Group, Inc. and Westinghouse Electric Company, LLC is providing engineering, procurement and construction ("EPC") oversight services. Finally, a recent analysis has shown that this model is likely to result in total project costs that are at least competitive with, if not lower than, alternative commercial strategies.[9]

While Concentric is in agreement with the selected commercial strategy, we do note that this model does not mirror Ontario Power Generation's previous experience with significant projects and that the Project team has limited experience in managing vendors under this model. Ontario Power Generation's limited experience in managing the vendor oversight function in a large, diverse, multi-prime contracting model will increase the importance of accessing external resources. Ontario Power Generation is appropriately meeting this need through a combination of Owner's Support Services vendors, and other outside consultants and

[9] Rojas, Eddy M., "Single Versus Prime Contracting," *Journal of Construction Engineering and Management*, October 2008, pp. 758-765.

as Ontario Power Generation selected from available contracting strategies at the Project level, it must do the same for the selection of a vendor for the Retube & Feeder Replacement work package.

B. Ontario Power Generation's Retube & Feeder Replacement Commercial Strategy

The commercial strategy selected by Ontario Power Generation for the Retube & Feeder Replacement agreement is a hybrid EPC agreement that combines elements of fixed/firm pricing for known or highly definable tasks and a target price for the remaining scope of the Retube & Feeder Replacement work package where less detailed information is available.[12] Additionally, Ontario Power Generation's commercial strategy has incorporated a phased project schedule that will divide the work into a definition phase, an execution phase and a commissioning phase. During the definition phase, Ontario Power Generation and its selected vendor will complete the detailed design of the Project, procure long lead materials, fabricate long lead components and tools, test the specialized tooling and complete final planning activities. At the conclusion of the definition phase work, Ontario Power Generation and its selected vendor will complete a cost estimating process to determine the "execution phase target price." The execution phase target price will create an estimate of the total cost to complete the execution phase work with upper and lower cost sharing bands. Within these cost sharing bands, Ontario Power Generation and the selected vendor will jointly share in cost over-runs or under-runs. Outside of these cost sharing bands, the Retube & Feeder Replacement agreement reverts to a cost reimbursable agreement, excluding vendor profit and overhead. Ontario Power Generation will, likewise, include financial incentives for early completion of each unit outage and financial penalties for failure to complete unit outages within the agreed upon schedule. If Ontario Power Generation and the selected vendor are unable to agree on an execution phase target price and schedule, Ontario Power Generation will retain the tooling in order to conduct the execution phase work with an alternate contractor.

Concentric's review of the Project's Retube & Feeder Replacement contracting strategy has highlighted the following advantages and disadvantages of this approach:

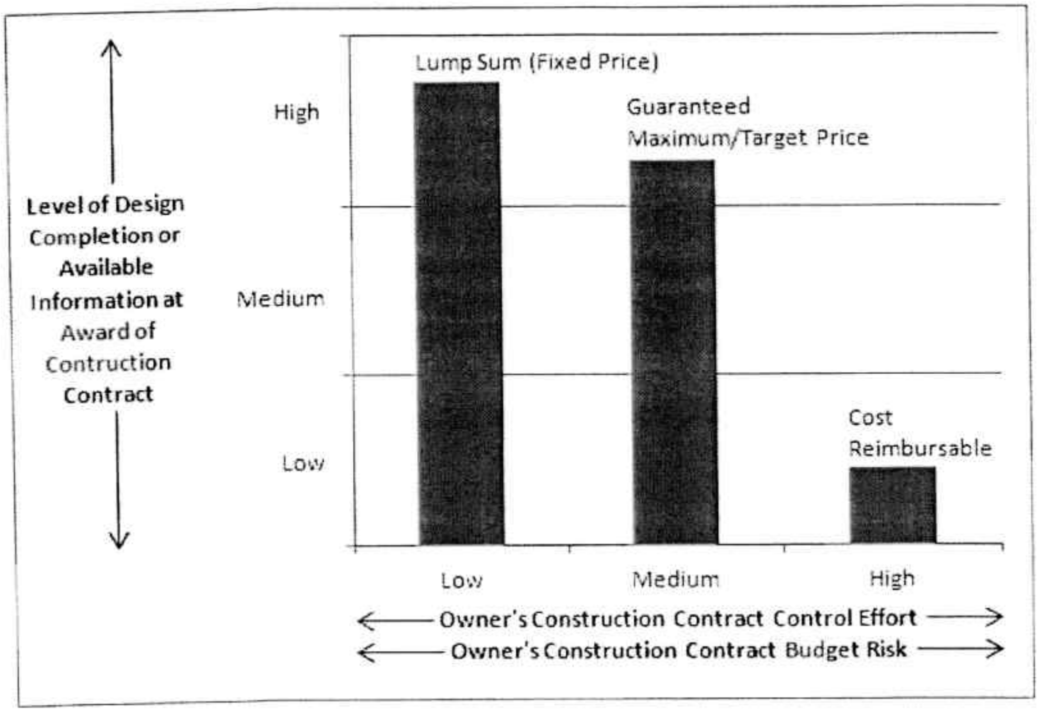
- Advantages: Flexibility to adapt to the project's evolving project scope; incentives are created to limit cost increases and schedule delays; control over the design of station modifications.
- Disadvantages: Creates substantial oversight responsibilities; once the cost for each unit exceeds the target price and caps for each unit, the contract is essentially a cost reimbursable (excluding vendor overhead and profit) agreement with a more limited risk transfer relative to a fixed price agreement.

C. Basis for Selection

The current hybrid EPC strategy for the Retube & Feeder Replacement work package was selected in order to fulfill several objectives. Specifically, Ontario Power Generation reviewed prior operating experience from similar refurbishment projects and determined the need to retain overall control and responsibility for project management and design authority. The operational experience reviewed included specific lessons learned

[12] This EPC agreement differs from the Engineering, Procurement and Construction agreement employed by NB Power at Point Lepreau in that the agreement relates to only a single work package and includes a hybrid pricing structure.

Figure 1: Pricing Models and Relationships between Scope Certainty and Contract Control/ Budget Risk



Contractual attempts to fully shift accountability to the vendors may not always be achievable or may command too high a risk premium. In instances where risk and accountability are not fully transferred, OPG will utilize incentive mechanisms to align OPG and vendor behaviour and outcomes and effective oversight to ensure alignment of the vendor's interests with OPG's. For risks retained by OPG, OPG will develop appropriate risk mitigation or management techniques including the use of a risk-based contingency. OPG will seek to transfer those risks that are truly controllable by the vendors. In addition, each Project will be supported by a Project Risk Register that outlines risks, impacts, and mitigations and identifies those that will be transferred to the Vendor.

5.0 DR PROGRAM OBJECTIVES

The DR Commercial Strategy is an enabler to deliver the project goals. The relationship between the strategy and guiding principles with OPG's and DR Program objectives are set out in the diagram below.

world nuclear news

CORPORATE

Gentilly 2 refurbishment postponed

18 August 2010

Hydro-Quebec has decided to postpone the start of refurbishment work at the Gentilly 2 reactor by about one year. The company decided in August 2008 to refurbish the Candu unit as an alternative to closing it in about 2011.

Gentilly 2 (Image: Hydro-Quebec)

Gentilly 2 is a 638 MWe Candu pressurized heavy-water reactor (PHWR) built by state-owned Atomic Energy of Canada Ltd (AECL) between 1974 and 1982. The unit was commissioned in October 1983. Candu reactors require refurbishment and replacement of core components after about 25-30 years of operation. The process is meant to extend the unit's life by about the same amount.

Two years ago, Hydro-Quebec announced that it would invest some C$1.9 billion ($1.8 billion) to refurbish the Canadian province's sole operating nuclear power reactor, thereby extending the unit's operating life to about 2040. At that time it said that engineering and procurement work for the refurbishment would start before the end of 2008 and construction work would begin in 2011. Construction activities consist of refurbishing the reactor, the turbo-generator unit, as well as the control and support systems. The refurbished reactor was scheduled to return to service in 2012 with an increased power generating capacity, although no figure has been specified.

In February 2009, GE Energy was awarded a contract worth more than $120 million by Hydro-Quebec to refurbish the turbine island, replacing rotor windings and the moisture separator-reheaters. In addition, the two low-pressure steam turbine rotors and diaphragms must be replaced and adjustments made to the turbine base plate. A new control system will also be installed.

However, Hydro-Quebec has now said that the start of work on the refurbishment of the unit will now begin in 2012. In a statement, the company said that the decision to postpone the start of work was "made in the context of the revision of the schedule of repairs being made at the Point Lepreau Candu plant in News Brunswick and at Wolsung, South Korea." It added, "In addition, this postponement will provide the necessary assurances regarding the identity of the next owner of AECL, the leading supplier and contractor in the refurbishment project."

The Point Lepreau nuclear power plant in New Brunswick - considered Gentilly-2's twin as both use Candu-6 reactors - is currently being refurbished at a cost of C$1.4 billion ($1.3 billion) to add another 25 years of operating life.

Point Lepreau is the first Candu-6 reactor to undergo major refurbishment, including replacement of all of its 380 fuel channels and associated feeder tubes. When the reactor was shut down for refurbishment in March 2008 the project was expected to take 18 months to complete and thus only cover one winter. However, the first-of-a-kind work has over-run, and general contractor AECL subsequently pushed back the completion date to October 2010, then to February 2011. Recently AECL confirmed that the refurbishment will now take at least another year to complete, pushing the restart back to February 2012 at the earliest.

In 2006, AECL was awarded a large contract by Korea Hydro and Nuclear Power (KHNP) for the retubing of the Wolsong 1 Candu-6 reactor to enable the unit to operate for an additional 25 to 30 years. The terms of the contract include completion of the retubing for a fixed price and to a fixed schedule with an outage of about a year and a half. The retubing project started in April 2009.

Hydro-Quebec said that it will continue to invest in the regular operating activities at the plant and "will closely monitor the ongoing renovations at Point Lepreau and Wolsong to take full advantage of the lessons learned from this work."

In June 2009, the Canadian government announced that it would seek buyers for a stake AECL's nuclear reactor business and bring aboard private-sector management for its ailing Chalk River nuclear facility. In December, the minister of natural resources, Lisa Raitt, invited investors to submit proposals for AECL's commercial Candu reactor division, the next step in restructuring the Crown Corporation.

Researched and written
by World Nuclear News

Thus, RQE for Refurbishment is intended to be a Class 2 Estimate, a type of estimate that typically forms a project's "Control Budget." By utilizing this methodical approach to developing RQE, the DR Team should be able to produce a high-confidence estimate against which the Project's performance can be properly measured so long as each of the inputs are carefully vetted and understood. It is also important to understand and accurately characterize what each of the estimates represent prior to RQE within the context of the level of project definition and the accuracy range. It is not unusual on highly visible projects for actual project costs to be compared against early (i.e. Class 5) point estimates without a discussion of their accuracy ranges, which could mislead external stakeholders.

A concept within the estimate that is commonly misunderstood is the application of contingency. Contingency is included in the base estimate and refers to costs that will probably occur based on past experience. As a result, contingency is expected to be spent as the project progresses through its life cycle. The utilization of contingency is not an indication of poor management.

OPG is taking significant steps in engineering and scope definition in order to provide a fundamental basis for RQE by: 1) utilizing the AACE guidelines to characterize the Project's scope and engineering maturity through a progression of cost estimates; 2) completing detailed engineering prior to the start of construction for all work; and 3) mitigating potential performance risk and estimating errors through construction and the use of a full scale mock-up for RFR. Proper planning of the execution phase of the Project will provide confidence in the reliability of RQE as well as minimize the risks of cost and schedule overruns during construction.

D. Timeline of Key Events

The following timeline of key events shows the parallel development of the Campus Plan Projects and the Refurbishment Project.

Date	Key Events
	Early Project Development – Initiation Phase (2006 to 2010)
2006 – 2010	• Feasibility studies for DNGS Refurbishment, leading to February 2010 announcement of Refurbishment Project • DR Program Charter approved • D2O Storage and Auxiliary Heat Steam system projects approved, then put on hold • Refurbishment Project's Scope Definition Phase begins, categorizing core and non-core scope • Environmental Assessment Studies submitted to the CNSC • Procurement process for RFR project begins
	Refurbishment Project Definition Phase (2011 to Current)
2011	• Bill Robinson retires; replaced by Albert Sweetnam as SVP of Nuclear Projects • Mike Peckham named VP of Projects & Modifications • OPG submits Integrated Safety Review (ISR) to CNSC • Environmental Impact Statement issued • Project charter for D2O Storage project issued August 2011; high-level scope and estimate of $210M provided to P&M management • Refurbishment Project' Release 4a Cost Estimate provided to Board of Directors
1Q 2012	• P&M negotiates and executes Extended Service - Master Service Agreements ("ESMSA") with two vendors – Black & McDonald and ES Fox – for use on Campus Plan Projects • SNC/Aecon Joint Venture selected as EPC for RFR project
2Q 2012	• D2O Storage Gate 3A conducted with revised EPC Project estimate - $108M • DR scope review conducted to identify potential scope to be deferred
3Q 2012	• AHS bid and award of EPC to [redacted] – total project estimate - $45.6M
4Q 2012	• P&M seeks full funding releases for D2O Storage and AHS • Refurbishment Project Release 4b cost estimate shows potential for upward pressure on budget

misunderstood is the application of contingency. Contingency is included in the base estimate and refers to costs that will probably occur based on past experience. As a result, contingency is expected to be spent as the project progresses through its life cycle."

Do I understand that correctly to mean that from your perspective the realistic cost estimate that people should have in mind for this project is the 10 billion, roughly 10 billion, depending whether you include interest and escalation, that estimate, rather than the point estimate, which I am not going to mention on the public record, but that is without contingency and management reserve?

MR. GOULD: That's correct.

MR. POCH: Okay.

MR. REINER: Can I maybe just by way of clarification --

MR. POCH: By all means.

MR. REINER: A point estimate does include contingency. It does not include management reserve, but it does include contingency. So if you --

MR. POCH: We will come back to that in candid session just so I can nail down precisely which numbers we are referring to, but that's fine.

In any event, I would like to also return to JT2.2 that you were discussing with Mr. Elson a few minutes ago, and in particular part (c). And that's where you provided a table of the costs and LUECs for various percentage cost

Appendix A: Ontario's History of Nuclear Cost Overruns and Ontario Hydro's Stranded Nuclear Debt

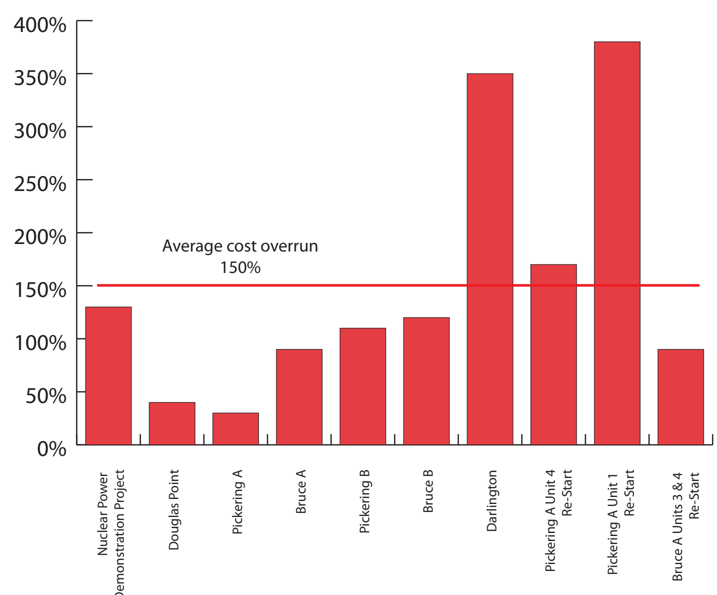
Ontario's History of Nuclear Cost Overruns

Every nuclear project in Ontario's history has gone over budget.

- The original cost estimate for the 20 megawatt (MW) Nuclear Power Demonstration Project on the Ottawa River was $14.5 million.[39] The actual cost was 2.3 times higher at $33 million.[40]
- The original cost estimate for the 200 MW Douglas Point Nuclear Power Station on Lake Huron was $60 million.[41] The actual cost was 1.4 times higher at $85 million.[42]
- In 1967 Ontario Hydro estimated that the 2,160 MW Pickering A Nuclear Generating Station would cost $527.65 million.[43] The actual cost was 1.3 times higher at $700 million.[44]
- In 1969 Ontario Hydro estimated that the 3,200 MW Bruce A Nuclear Generating Station would cost $944 million.[45] The actual cost was 1.9 times higher at $1.8 billion.[46]
- In 1975 Ontario Hydro estimated that the 2,160 MW Pickering B Nuclear Generating Station would cost $1.8 billion.[47] The actual cost was 2.1 times higher at $3.8 billion.[48]
- In 1975 Ontario Hydro estimated that the cost of the 3,200 MW Bruce B Nuclear Generating Station would be $2.7 billion.[49] The actual cost was 2.2 times higher at $5.9 billion.[50]
- In 1975 Ontario Hydro estimated that the cost of the 3,400 MW Darlington Nuclear Generating Station would be $3.2 billion.[51] The actual cost was 4.5 times higher at $14.319 billion.[52]
- In 1999 Ontario Power Generation (OPG) estimated that the total cost of returning the shutdown Pickering A Unit 4 to service would be $457 million.[53] The actual cost was 2.7 times higher at $1.25 billion.[54]
- In 1999 OPG estimated that the total cost of returning the shutdown Pickering A Unit 1 to service would be $213 million.[55] The actual cost was 4.8 times higher at $1.016 billion.[56] Nevertheless, a February 2010 OPG news release asserted that the project was completed "on budget".[57]
- Bruce Power estimated that the total cost of returning the shutdown Bruce A Units 3 and 4 to service would be $375 million. The actual cost was 1.9 times higher at $725 million.[58]
- In 2005 the Ontario Power Authority signed a contract with Bruce Power for the return to service of the shutdown Bruce A Units 1 and 2. In 2005 the estimated capital cost was $2.75 billion. The units have still not been returned to service, but in February 2010 TransCanada Corp. (a major shareholder of Bruce Power) estimated that the project will cost $3.8 billion.[59]

On average, the actual costs of the Ontario nuclear projects that have been completed to-date have exceeded their original cost estimates by 2.5 times.

Ontario's History of Nuclear Cost Overruns



Fool me once, shame on you. Fool me twice, shame on me. Fool me 11 times...

UNDERTAKING JT2.3

Undertaking

To provide a percentage breakout of contract values by fixed price, target price and any other structure in the contracts for the table provided in response to GEC Interrogatory 2.

Response

The following table provides, by major project, life cycle contractor estimates based on the overall estimate as provided in Ex. D2-2-1, Attachment 5.

		2013 $M	%
RFR	Tooling (Fixed Price)	357	[redacted]
	Mock-up (Fixed Price)	38	[redacted]
	Owner Specified Materials (Cost Plus)	165	[redacted]
	Definition Phase (Target Price/ Fixed Fee)	142	[redacted]
	Execution Phase (Target Price/ Fixed Fee)	[redacted]	[redacted]
Fuel Handling	Defueling - Engineering Services (Fixed/Firm Price)	16	[redacted]
	Defueling – Eng. Services (Misc. Reimbursables)	2	[redacted]
	Fuel Handling (Target Price)	[redacted]	[redacted]
Steam Generators	Fixed Price	60	54
	Target Price/ Fixed Fee	30	27
	EPC Other	21	19
Turbine Generator	Eng. Services & Equipment Supply (Fixed Price)	200	[redacted]
	Eng. Services & Equipment Supply (Target Price)	142	[redacted]
	Installation - Definition Phase (Target Price/ Fixed Fee)	29	[redacted]
	Installation – Execution Phase (Target Price/ Fixed Fee)	[redacted]	[redacted]
	EPC Other	33	[redacted]
Balance of Plant	EPC Time and Material/Target Price	[redacted]	[redacted]