EB-2010-0008

GEC CROSS MATERIALS

For OPG Panel 6

Chart 1 Revenue Requirement Impact of Darlington Refurbishment Project ($M)

Line No.	Description	Test Period Revenue Requirement Impact
		(a)
	PRESCRIBED FACILITIES	
	Return on Rate Base:	
1	Accretion Rate on Lesser of ARC and UNL	73.2
2	CWIP in Rate Base Impacts	32.7
3	Extension to Darlington Service Life Impacts	7.3
4	Total Return on Rate Base Impact	113.3
	Depreciation Expense:	
5	Asset Retirement Costs	(181.1)
6	Extension to Darlington Service Life Impacts	(48.5)
7	Total Depreciation Expense Impact	(229.6)
	Other Expenses:	
8	Used Fuel Storage and Disposal Variable Expenses	8.2
	Income Taxes:	
9	Accretion Rate on Lesser of ARC and UNL	25.3
10	CWIP in Rate Base Impacts	5.2
11	Extension to Darlington Service Life Impacts	1.2
12	Depreciation Expense on Asset Retirement Costs	(62.8)
13	Used Fuel Storage and Disposal Variable Expenses	2.8
14	Depreciation Expense on Darlington Service Life	(16.8)
15	Total Income Tax Impact	(45.0)
16	Total Revenue Requirement Impact - Prescribed Facilities	(153.1)
	(line 4 + line 7 + line 8 + line 15)	
	BRUCE FACILITIES	
17	Rate Base	0.0
18	Depreciation Expense Impact: Asset Retirement Costs	(40.2)
	Other Expenses:	
19	Accretion	(18.3)
20	Used Fuel Storage and Disposal Variable Expenses	4.2
21	Total Other Expenses Impact	(14.1)
	Income Taxes:	
22	Impact on Bruce Facilities' Income Tax Calculation	13.9
23	Impact on Prescribed Facilities' Income Tax Calculation	(14.0)
24	Total Income Tax Impact	(0.1)
25	Total Revenue Requirement Impact - Bruce Facilities	(54.4)
	(line 17 + line 18 + line 21 + line 24)	
26	Total Revenue Requirement Impact of Darlington Refurbishment Project	(207.5)
	(line 16 + line 25)	

the Capacity Refurbishment Variance Account, thus ensuring that OPG only recovers the OM&A and capital costs that were actually spent. A description of the variance account is further discussed in Ex. H1-T1-S1.

Chart 2

Darlington Refurbishment Costs ($M)

	Actual 2007	Actual 2008	Budget 2008	Variance	Actual 2009	Budget 2009	Variance	Budget 2010	Plan 2011	Plan 2012
OM&A										
Initiation/Definition Phase	$0.4	$7.3	$18.4	($11.1)	$21.7	$22.7	($1.0)	$4.2	$5.0	$2.9
Campus Master Plan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.3	$0.9	$1.6
OM&A -Total	**$0.4**	**$7.3**	**$18.4**	**($11.1)**	**$21.7**	**$22.7**	**($1.0)**	**$5.5**	**$5.9**	**$4.5**
Capital										
Definition Phase	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$44.4	$42.2	$149.2
Campus Master Plan	$0.0	$0.0	$0.0	$0.0	$1.0	$0.0	$1.0	$28.6	$63.0	$106.6
Capital - Total	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$1.0**	**$0.0**	**$1.0**	**$72.9**	**$105.2**	**$255.8**

4.0 ALTERNATIVES AND ECONOMIC ANALYSIS

Alternatives

Alternative 1: Approve the overall strategy for the Darlington Refurbishment project and funding to proceed with the definition phase of the project with a release of funding for the Preliminary Planning Work Program in order to be ready to refurbish Darlington units as early as October 2015 – RECOMMENDED.

This alternative positions OPG to be ready to refurbish the Darlington Units as early as the fall of 2015, if required, or as late as October 2016. This alternative maximises the value of the Darlington units to OPG if the current nominal life of the units is achieved (210,000 EFPH). It effectively minimizes the risk of "idle time" on the later units, while forsaking some of the life of the earlier units in order to maximise value. It also positions OPG to be able to potentially start the units as early as 2015, if work programs proceed more expeditiously than planned. Efforts are being made to advance planning and infrastructure development activities to increase the project's flexibility in starting the refurbishment as much as one-year earlier (October 2015 vs. October 2016). This partially mitigates concerns that the pressure tubes in the Darlington units may not remain fit-for-service until their current nominal lives and may need to be refurbished earlier. Currently there is only a medium level of confidence that the nominal lives of the Darlington units will be achieved. OPG has launched the Fuel Channel Life Management Project in conjunction with industry partners in order to increase its confidence in the pressure tube life of the Darlington units.

Alternative 2: Delay the Approval of Proceeding to the Definition Phase of the Darlington Project by 1 or more years – NOT RECOMMENDED.

This alternative would result in a cessation of the work on the Preliminary Planning Work Program, including the development of required infrastructure to execute the program, in the Definition Phase, for 1 or more years, followed by potential subsequent project approval. This alternative would jeopardize OPG's ability to be ready to refurbish the Darlington Units by the Fall of 2016 and would rule out any chance of being ready by the Fall of 2015. The risk of potential "idle time" on units increases significantly, particularly if the pressure tubes in the Darlington units were not to achieve their current nominal lives. Given that there is currently only a medium level of confidence that the nominal lives of the Darlington units will be achieved, this alternative would not be a prudent alternative to undertake.

Alternative 3: Abandon the Darlington Refurbishment Project and do not Plan to Refurbish Darlington – NOT RECOMMENDED

An economic feasibility assessment of the refurbishment of Darlington has indicated that this is one of the most economic generation options available to OPG to maintain a significant footprint in the Ontario Electricity Marketplace. Refurbishment of the Darlington units is also supported by the Ontario Power Authority, as discussed below, as one of the best options to meet the need for base-load generation in the Province of Ontario going forward. 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, even at relatively low forecasts of fuel costs, more expensive on a life cycle basis than the Darlington Refurbishment Project and have significantly higher exposure to the risk of fuel costs increases, including the potential imposition of carbon taxes, during their operating lifetime. CCGT options are not normally selected for baseload supply. The economic assessment of the Darlington Refurbishment Project is discussed in more detail below.

The assessment found that the Levelized Unit Energy Cost (LUEC) of refurbishing and continuing to operate the Darlington units for a further 30 years is more attractive than alternative generation options, including Pickering B Refurbishment and Combined Cycle Gas Turbine (CCGT). The costs of New Nuclear remain speculative and this time, thus, a firm comparison to Darlington is not possible. Management believes that the LUEC range for Darlington Refurbishment compares very favourably to New Nuclear, based on known public information of the costs of New Nuclear.

On this basis, this Business Case recommends that there is little risk that the economics of Darlington Refurbishment would change significantly enough to make a decision to proceed with the expenditures in the Definition Phase of the Darlington Refurbishment project seem not to be a prudent path forward.

Pollution Probe Interrogatory #002

Ref: Ex. D2-T2-S1, pages 4-5
Minutes of Stakeholder Information Session 1, page 18

Issue Number: 4.5
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

Interrogatory

OPG estimates that the Darlington refurbishment project will have a LUEC of between 6 and 8 cents per kWh (2009$) excluding capitalized interest.

With respect to these LUEC estimates, please state OPG's assumptions with respect to the refurbishment project's:

a) pre-tax weighted average cost of capital;
b) after-tax weighted average cost of capital;
c) average annual capacity factor;
d) present value of the short-term, medium-term and long-term costs associated with the management of used nuclear fuel.

Response

OPG estimates that the Darlington Refurbishment project will have a Levelized Unit Energy Cost ("LUEC") of between $0.06/kWh and $0.08/kWh (2009$), however, the evaluation of LUEC includes capitalized interest.

The following are the assumptions used in calculating the LUEC for the Darlington Refurbishment project:

a) OPG does not use a Pre-tax Weighted Average Cost of Capital.

b) After-tax Weighted Average Cost of Capital = 7 per cent.

c) Average Annual Capacity Factor: a range of 82 per cent to 92 per cent was used.

d) OPG does not separate out its estimate of the costs of used fuel management into short-term, medium-term and long-term components. The cost of used fuel management used in the development of the LUEC estimates was $0.4/MWh (2009$), which is equivalent to the 0.04¢/kWh shown in Ex. L-7-038. A range of +/-30 per cent was used for sensitivity analysis.

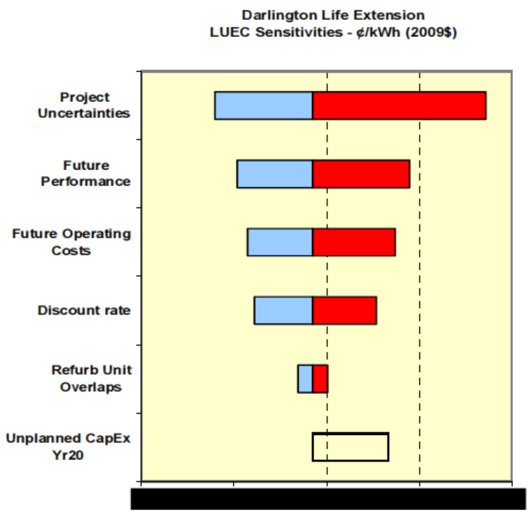
Filed: 2010-05-26
EB-2010-0008
Exhibit D2-2-1
Attachment 4

November 12, 2009

DARLINGTON REFURBISHMENT – PRELIMINARY RELEASE BUSINESS CASE

APPENIDX C – DETAILS OF THE ECONOMIC ASSESSMENT

Figure 3: Sensitivity Analysis – Darlington LUEC

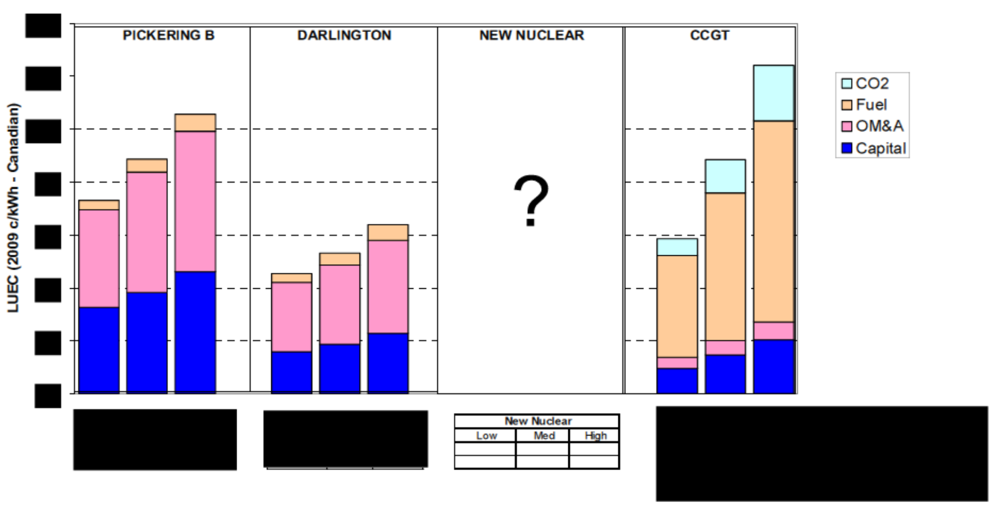


Assumptions	Lower	Base	Upper
Project Uncertainties			
Refurb Cost (2009$)	-15%	[redacted]	20%
Refurb Duration (months)	-6 mths		+12 mths
Future Performance			
ACF (%)	-5%	87%	5%
Life of Refurb Units (yrs)	+5 yrs	30 yrs	-5 yrs
Future Operating Costs			
Base OM&A ($M)	-5%	295	5%
Outage OM&A ($M)	-5%	95	10%
Sustaining Projects ($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

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 LUEC's of other options competing with this project. Figure 5 presents such a comparison.

Figure 5: Levelized Unit Energy Costs for Darlington Refurbishment and Comparators



Filed: 2010-08-17
EB-2010-0008
L-07-016
Attachment 1

PEOPLE POWERING THE FUTURE
OPG NUCLEAR

Summary of Economic Assessment

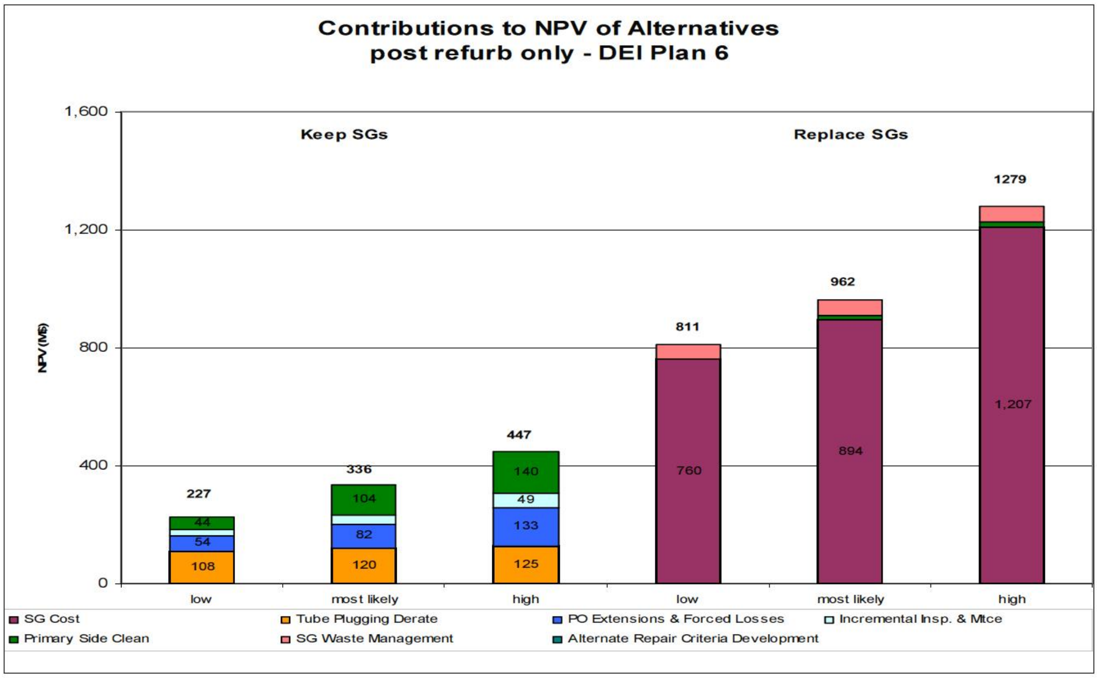
- A comprehensive economic analysis of two alternatives was completed:
  1. ***Keep SGs*** *(including required maintenance to address degradation)*
  2. ***Replace SGs*** *in Refurb Outage*
  - *A "Replace Later" alternative was addressed as a sensitivity.*
- The assessment of steam generator performance included degradation due to tube fouling, as well as costs of mitigation. A range of costs & performance were utilized in assessment.
- A range of SG replacement costs during refurbishment was also assumed.
- **<u>Results:</u>**
  - *Medium Confidence (30 – 70%) that the "Keep SGs" alternative was better economically than "Replace SGs" alternative by **$200M** to **$750M PV**.*
  - *The "Replace Later" PV costs would be the same as the "Replace during Refurbishment" PV costs provided the replacement could be done in 10 months and takes place more than 18 years post refurbishment. However there is a very high confidence in achieving 18 years safe, reliable, cost-effective operation post-refurbishment, with the existing SGs.*

ONTARIO POWER GENERATION

Filed: 2010-08-17
EB-2010-0008
I-07-016
Attachment 1

PEOPLE POWERING THE FUTURE OPG NUCLEAR

Comparison of Keep SGs & Replace SGs – Based on DEI Plan 6 – Post Refurb Costs Only



ONTARIO POWER GENERATION

Filed: 2010-08-17
EB-2010-0008
Issue 4.5
Exhibit L
Tab 7
Schedule 028
Page 1 of 2

GEC Interrogatory #028
(NON-CONFIDENTIAL VERSION)

Ref: Ex. D2-T2-S1

Issue Number: 4.5
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

Interrogatory

The statement on page 4 of attachment 4 of D2-2-1: "As recommended by Management in April, 2009, steam generator (SG) replacement has been excluded from the reference outage scope" is notable because other CANDU refurbishment projects have included steam generator replacement.

a) Please provide the low, media and high risk end-of-life estimates for the Darlington steam generators.
b) Please provide an approximate cost estimate for purchasing replacement steam generators for the Darlington nuclear station.
c) Please provide a description of the cost and work required to replace Darlington's steam generators?
d) If steam generator replacement were to take place at a date following of the proposed 36 month refurbishment outages, what would be the outage time required to replace the steam generators?
e) Have the costs of eventual steam generator replacement at Darlington been included in the LUEC price for the Darlington refurbishment? If not please provide the impact of a subsequent SG replacement on LUEC.
f) Has the Canadian Nuclear Safety Commission approved the exclusion of steam generator replacement from the scope of the Darlington refurbishment?
g) Has OPG evaluated the cost effectiveness of replacing Darlington steam generators if refurbishment outages were to take place as originally envisioned post 2018?

Response

Contrary to the suggestion in the preamble to this question, not all CANDU refurbishments include steam generator replacements. Steam generator replacement is not included in the project scope for the Pt. Lepreau, Wolsong and Gentilly refurbishments.

a) See response to the interrogatory in Ex. L-7-016. OPG does not have low, medium and high risk end-of-life estimates.

b) OPG has a range of estimates for the purchase and installation of new steam generators at the Darlington Generating Station. OPG has also compared the estimated costs of

Filed: 2010-08-17
EB-2010-0008
Issue 4.5
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Tab 7
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Page 2 of 2

steam generator replacement against the known costs of replacing steam generators in those United States plants which have either already completed or have planned replacements.

Based on these estimates, OPG estimates the cost of steam generator replacement to be [redacted]M/unit at Darlington. These costs would include purchase and installation. In addition, there are costs of waste management of the replaced steam generators, estimated at approximately [redacted]M per unit.

c) The estimated cost is provided in part b) above. The work involved would include draining and drying the existing steam generators, removing the existing steam generators, installing the new steam generators, re-connecting to the existing pipes, then refilling and testing the new steam generators during re-commissioning of the units.

d) The duration could range from 10 – 20 months depending on the assumptions made about the methodology for carrying out the work.

e) No, the eventual cost of steam generator replacement has not been included in the Levelized Unit Energy Cost ("LUEC") range provided for Darlington Refurbishment. However, OPG believes that the range adequately covers such potential costs. The specific impact on the estimated LUEC if the steam generators needed to be replaced in a subsequent outage would be less than [redacted]. However, the impact on the LUEC is very dependent on the timing of when that replacement would occur.

f) Canadian Nuclear Safety Commission ("CNSC") approval of this decision is not required.

g) OPG has never previously established a plan for the refurbishment of Darlington Generating Station and therefore cannot respond to this question. The meaning of the reference to "refurbishment outages … as originally envisioned post 2018" is unclear.

AMPCO Interrogatory #018

Ref: Ex. D2-T2-S1, Attachment 4

Issue Number: 4.5
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

Interrogatory

a) Regarding page 23, please comment on why OPG is not pursuing a Low Void Reactivity Fuel option for Darlington.

b) At Appendix C Section 1.1.2 OPG refers to having completed benchmarking on the refurbishment projects “such as Pt. Lepreau and the Bruce 1 & 2 Units”. Please provide this analysis.

c) Regarding Appendix C Section 1.1.4, please compare the duration estimate OPG has made for calandria tube installation for each unit with the experience currently underway at Point Lepreau and comment on the difference.

Response

a) OPG is not pursuing a Low Void Reactivity Fuel option for Darlington Generating Station because the safety analysis performed for the Darlington Generating Station reactor design, and submitted to the Canadian Nuclear Safety Commission (“CNSC”), has demonstrated that the safety margins using natural uranium fuel are adequate.

b) The interrogatory response in Ex. L-02-015 provides a listing of publicly available information OPG considered in the preparation of its economic feasibility assessment. Additionally, OPG is a member of the Plant Refurbishment Working Group of the CANDU Owner’s Group. This group meets informally to share their operating experiences (“OPEX”) around refurbishment planning and execution activities. OPG has visited CANDU units at Bruce, Pt. Lepreau, Wolsong (Korea) and Gentilly 2 to review and observe their ongoing activities.

c) Our schedule estimates were based upon the details from the retube feasibility study prepared for OPG by GE/Hitachi, which incorporated operating experience from Pt. Lepreau and Bruce. The estimates also incorporated the fact that Darlington Generating Station has about 100 more fuel channels in its reactor core than those at Pt. Lepreau, Wolsong and Gentilly 2.

At the time the study was underway no CANDU unit under refurbishment had progressed beyond the tube and feeder removal stage. Currently all the CANDU in-progress refurbishments are now into Calandria Tube ("CT") installation work. A significant issue has arisen with respect to the ability to complete a reliable leak tight rolled joint, resulting in suspension of the CT work. Atomic Energy of Canada Limited ("AECL"), working with the impacted utilities, has made changes to the tooling and installation processes to solve the problem and the CT installation work is anticipated to resume shortly. OPG will consider this OPEX when developing its final project plans.

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 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.

Gentilly 2 (Image: Hydro-Quebec)

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

ONTARIO POWER GENERATION

Nuclear Refurbishment Key Risks

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RISK	IMPACT	CONSEQUENCE	PROBABILITY	MITIGATION
Darlington units do not reach predicted EOSL (based on 210k EFPH) resulting in idle units and/or advancement of DN Refurbishment.	• Increased idle time of units and/or starting refurbishment without adequate plans.	High	Medium	• Fuel Channel Life Management project will review confidence of reaching 210k EFPH. • Advanced planning activities to be ready by 2015. • Assets will be life-managed to achieve 2015.
Insufficient infrastructure planning or time to develop infrastructure	• Not ready to start refurbishment due to incomplete infrastructure.	High	Low	• Infrastructure planning and development commencing in 2010 with a partial release included in Release # 3.
CNSC timing/ costs to complete the review and provide approval to EA, ISR, IIP.	• Delay in refurbishment outage start date.	High	Medium	• Working with the CNSC to develop a plan to obtain approval of all documents.

APPENIDX C – DETAILS OF THE ECONOMIC ASSESSMENT

1.2. Post-Refurbishment Assumptions

To fully assess the merits of the option to proceed with the refurbishment of the Darlington plant, all future expected costs of operating the facility over its post-refurbishment life, as well as the expected operating performance of the plant and expected unit life must be forecasted.

1.2.1. Unit Life

Since the Darlington units will have been in service for approximately 60 years (not including the time out-of-service for refurbishment) by the end of their post-refurbishment lives, it is considered prudent to utilize conservative assumptions for unit lives for the economic assessment, in order to mitigate the risk that an unforeseen equipment issue could emerge which could bring about an earlier than expected end of post-refurbishment life.

The post-refurbishment life of each unit was assumed to be nominally 30 calendar years. This post-refurbishment calendar life was derived from the current design life of pressure tubes of 24 effective full power years (210,000 effective full power hours) with some recognition that, given the knowledge gained about pressure tube degradation mechanisms, future pressure tubes will likely be designed to achieve longer service lives. Thirty calendar years, with an assumed 87% capability factor translates into a pressure tube life of 25.5 effective full power years (approx. 224,000 effective full power hours).

Sensitivities on unit lives were run at 25 calendar years and 35 calendar years respectively.

1.2.2. Annual Station Operating, Maintenance & Projects Costs

The 2012 data from the approved 2008-2012 business plan was used to derive the expected annual OM&A for the post-refurbishment period. Annual OM&A levels were derived based on forecast changes to programs and were estimated to be nominally the same as the current 2008-2012 Business Plan averages over the post-refurbishment period. These values have been re-verified against the assumptions in the 2009 – 2013 business plans and verified again versus preliminary numbers in the 2009 – 2014 Business Plan.

The post-refurbishment outage costs were developed based on expected work programs and typical outage templates. These were increased during the last 10 years of post-refurbishment life. The outage costs include allowances for periodic 4-unit shutdowns for the Vacuum Building Inspections and Containment Testing.

Expenditures for ongoing sustaining projects of $28M/unit/yr was assumed, which is consistent with the nuclear project portfolio assumptions. This was modified by assuming that, in the first year post-refurbishment, 50% of the "typical' annual project costs would be incurred, ramping up to 100% by the 5th year.

The following table provides details on the assumptions used for these factors in the analysis.

Filed: 2010-08-17
EB-2010-0008
Issue 4.5
Exhibit L
Tab 10
Schedule 003
Page 1 of 2

Pollution Probe Interrogatory #003

Ref: Ex. D2-T2-S1, pages. 4 and 5
Minutes of Stakeholder Information Session 1, page 18

Issue Number: 4.5
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

Interrogatory

OPG estimates that the Darlington refurbishment project will have a LUEC of between 6 and 8 cents per kWh (2009 dollars) excluding capitalized interest.

Please provide a break-out of OPG's LUEC estimates according to at least the following categories:

a) capital costs;
b) fixed operating, maintenance & administration;
c) fuel cost;
d) variable operating, maintenance & administration;
e) short-term, medium-term and long-term costs associated with the management of used fuel.

Response

The question is incorrect in stating that OPG's estimates of the Levelized Unit Energy Cost ("LUEC") range exclude capitalized interest. The evaluation of LUEC includes capitalized interest.

The range of \$0.06/kWh – \$0.08/kWh for the LUEC of Darlington Generating Station (Ex. D2-T2-S1, page 8, Figure 1) is based on a Monte Carlo analysis where a significant degree of variability is introduced into the different inputs to the LUEC calculation (e.g., refurbishment costs, post-refurbishment costs and performance and post-refurbishment station life). The LUEC range of \$0.06/kWh – \$0.08/kWh has a medium to very high confidence range.

Because OPG's range estimate is based on a Monte Carlo analysis, it is not possible for OPG to provide the breakdown of the capital costs, operating costs and fuel costs which make up the upper and lower bound of the range or of any points in-between. However, OPG can provide the following, based on its preliminary high confidence estimates:

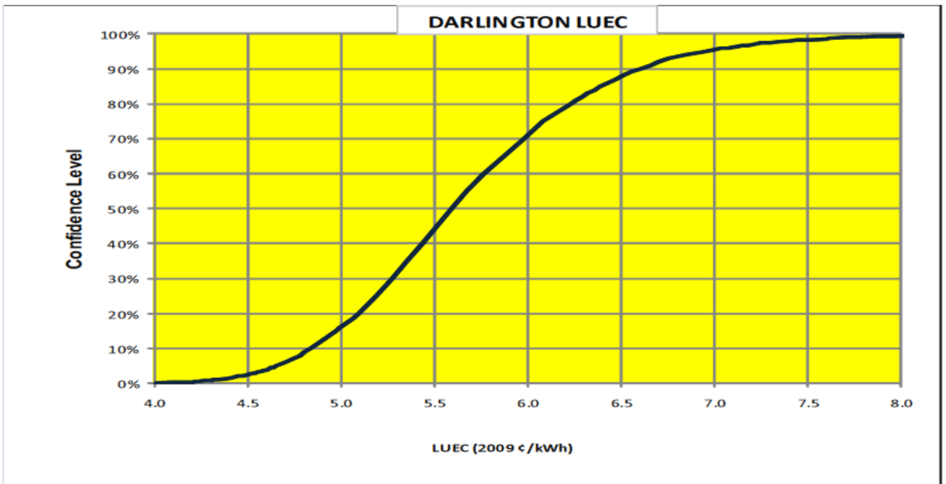
Expected "Typical" Refurbishment Costs, Operations Maintenance & Administration and Fuel Cost Ratios in the LUEC for Darlington Refurbishment

Component of LUEC	% of LUEC
Refurbishment Costs	35
OM&A Costs	55
Fuel (including used fuel management)	10
Total	100

OPG does not separate out its estimate of the costs of used fuel management into short-term, medium-term and long-term components.

Figure 1

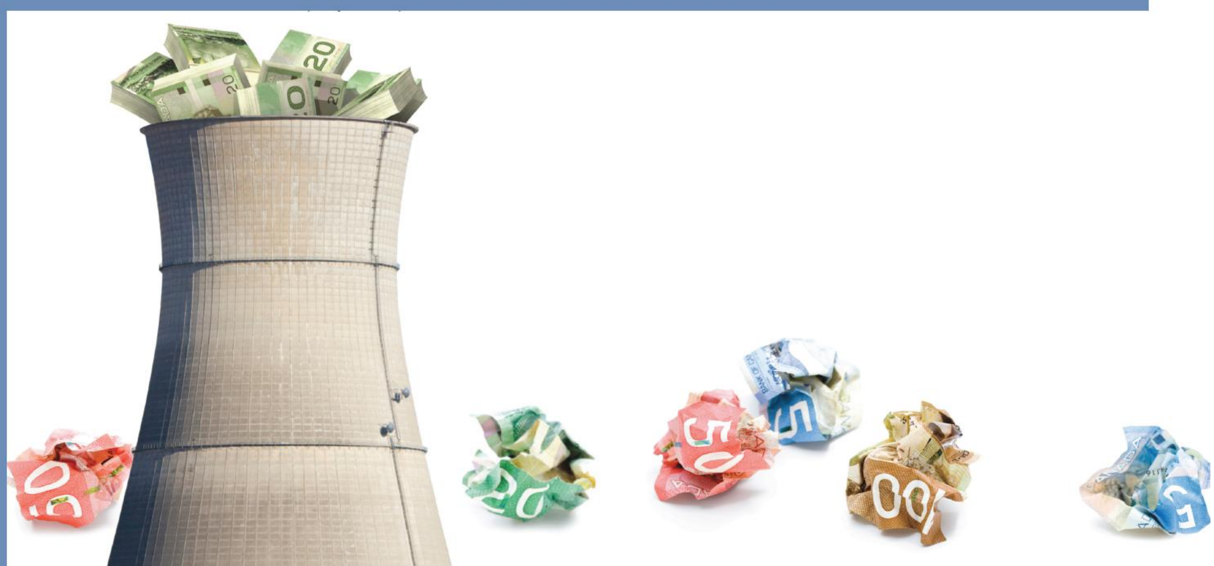
Levelized Unit Energy Cost Confidence Ranges



The LUEC range shown in Figure 1 above is based on a number of planning assumptions; including 1) refurbishment project cost, 2) refurbishment schedule, 3) post refurbishment operations costs, and 4) post refurbishment operating performance:

1) Refurbishment Project Cost - Based on the current level of planning as well as a review of industry experience, the current projected cost of the refurbishment project is in the range of $6B to $10B (2009 dollars).
2) Refurbishment Schedule - OPG's planning assumption was that the first unit refurbishment outage would commence in October 2016 and that each unit outage will last approximately 36 months. It is also assumed that unit refurbishment outages will be overlapped with a maximum of two units in a refurbishment state at any point in time. These assumptions are based on the current predicted end of service life, information received from technical studies on the project's critical path duration and replacement costs, and the current experience of other refurbishments.
3) Post-Refurbishment Operations Costs – A range of $450M to $525M per year (2009 dollars) of post-refurbishment station costs, including operations, outages, and projects,

The Darlington Re-Build Consumer Protection Plan



AN OCAA RESEARCH ENERGY REPORT | www.cleanairalliance.org

Ontario Clean Air Alliance Research Inc.

SEPTEMBER 23, 2010

Darlington Re-Build Proposal

The purpose of Ontario Power Generation's (OPG's) proposed Darlington Re-Build project is to extend the operating life of the Darlington Nuclear Generating Station by 30 years.[1]

OPG is seeking permission from the Ontario Energy Board (OEB) to raise its rates commencing March 2011 to finance the Darlington Re-Build "Definition Phase" and the "Darlington Site Campus Master Plan". The expenditures for the Definition Phase include: "the establishment of the project organization, scope finalization, engineering, planning and estimating, procurement of long lead time items and contract establishment. Additionally, all regulatory work will be completed in this phase including the EA [Environmental Assessment], ISR [Integrated Safety Review], Global Assessment and the IIP [Integrated Improvement Plan]." The Campus Master Plan includes facilities and infrastructure upgrades to support the Darlington Re-Build.[2]

OPG is planning to spend $1.1 billion on the Definition Phase and Campus Master Plan between 2011 and 2014.[3]

In 2014, OPG's management will "revise its feasibility assessment, establish the project scope, cost and schedule" and seek approval from its Board of Directors to proceed with the Darlington Re-Build "assuming that the economics of the project remain favourable."[4]

The Economics of the Darlington Re-Build Proposal

According to OPG's preliminary economic analysis, the Darlington Re-Build will have a capital cost of $8.5 to $14 billion[5] and will provide electricity at a cost of 6 to 8 cents (2009$) per kWh.[6] OPG's economic analysis is problematic for at least four reasons.

1. According to OPG, its input variables (e.g., re-build costs, post re-build costs, performance and post re-build station life) for the Darlington Re-Build are "fairly uncertain at this early stage".[7]

2. OPG's 6 to 8 cents per kWh estimate is based on the assumption that a re-built Darlington will have an average annual capacity utilization rate of 82 to 92%[8] despite the fact that Ontario's fleet of nuclear reactors has never achieved an average annual capacity utilization rate of 82% or better during the last 25 years.[9]

   To-date, OPG has re-built two nuclear reactors, namely Pickering A Unit 4 which was returned to service in 2003 and Pickering A Unit 1 which was returned to service in 2005. The average annual capacity utilization rate of Unit 4 during the last four years (2006 to 2009) was 59%.[10] In 2004 the OPG Review Committee, which was chaired by John Manley, recommended that OPG continue with the Pickering A Unit 1 Re-Start based on the assumption that it would have an average annual capacity utilization rate of 85%.[11] However, its actual average annual capacity utilization rate during the last four years has been only 69%.[12] Therefore the average annual capacity utilization rate of the Pickering A Units 1 & 4 nuclear reactors during the past four years was only 64%.

   To-date Bruce Power has re-built two of its nuclear reactors, namely, Bruce A Units 3 and 4. Their average annual capacity utilization rate during the last four years was 75%.[13]

   According to OPG, assuming a 64% annual average capacity utilization rate, the Darlington Re-Build Proposal's cost of electricity would rise to 8 to 10 cents per kWh (2009$).[14]

   While the current Darlington reactors have performed better than the fleet average, the established pattern is for a large drop off in performance as CANDU units age and there is no precedent for re-built reactors achieving capacity factors of 82% or better.

3. OPG has underestimated the required commercial risk-adjusted rate of return on capital for this high-risk project. Specifically, OPG assumes the project can be 53% debt financed and its required rate of return on equity would be only 9.85%.[15] On the other hand, according to CIBC World Markets, only 20 to 40% of Bruce Power's Bruce A Units 1 and 2 Re-Start project could be debt financed and its required return on equity could be up to 18%.[16] According to OPG, assuming 30% debt financing and a 18% return on equity, the cost of the Darlington Re-Build rises to 10 to 14 cents per kWh (assuming an 82% average annual capacity utilization rate) or 12 to 18 cents per kWh (assuming a 64% average annual capacity utilization rate).[17]

4. OPG's analysis assumes that the Darlington Re-Build project will be completed on budget despite the fact that every nuclear project in Ontario's history has experienced huge capital cost overruns (see Appendix A). Similarly, the retrofit of the Point Lepreau reactors in New Brunswick is reported to be massively over budget despite assurances at the outset of the project that the pattern of massive cost overruns would not be repeated. [66]

   On average, the actual costs of Ontario's nuclear projects have been 2.5 times greater than their original cost estimates. If the Darlington Re-Build's actual cost exceeds OPG's original cost estimate range by 2.5 times then its final cost will be $21.25 to $35 billion. As a consequence, it will produce electricity at a cost of 19 to 27 cents per kWh (assuming an 82% average annual capacity utilization rate) or 24 to 37 cents per kWh (assuming a 64% average annual capacity utilization rate).[18]

Lower Cost and Lower Risk Options

Fortunately Ontario has numerous lower cost and lower risk options to meet its electricity needs. Specifically, improving energy efficiency; reducing wasteful natural gas usage; and water power imports from Quebec.

Energy Efficiency

Energy efficiency is the lowest cost option to meet our electricity needs. However, as the following facts reveal the Ontario Power Authority (OPA) is not aggressively pursuing the province's low cost energy efficiency investment opportunities.

1. As of December 31, 2009, the OPA's total spending on energy conservation and demand management was $541.6 million; whereas it has contracted for electricity supply projects with a total capital cost of $23.622 billion.[19] That is, for every dollar that it has spent on energy conservation and demand management, it has contracted for $44 of new supply.

2. The OPA's *Industrial Accelerator Program* pays large industrial customers up to 23 cents for each kWh that their energy efficiency investments save *during the first year* of their operation. [20] Assuming these investments actually deliver savings for at least 5 to 10 years, a payment of 23 cents per kWh saved *during the first year* is equivalent to an average annual payment of only 2.3 to 4.6 cents per kWh. That is, OPA's payments for saving a kWh are therefore 76 to 94% less than the cost of producing a kWh by re-building Darlington.

Ending Wasteful Natural Gas Use

Most buildings and factories in Ontario use natural gas to produce just one service, namely heat. It is much more efficient to use these same molecules of natural gas to simultaneously produce heat and electricity. This is what combined heat and power (CHP) plants do. They can have energy efficiencies of 80 to 90% compared to the 33% energy efficiency of a nuclear reactor.[21]

CHP plants can be installed in apartment buildings, condominiums, shopping centres, hospitals, schools, airports and factories.

According to the OPA, CHP plants can supply electricity at a total cost of 5.7 to 6.0 cents per kWh assuming a natural gas cost of $8 per

MMBTU.[22] [On August 27, 2010 the spot price of natural gas was $3.74 (U.S.$) per MMBTU at Henry Hub].

Ontario's existing CHP capacity is 1,281 megawatts (MW).[23] There are three available estimates of Ontario's total CHP potential capacity:

1. According to industry expert Tom Casten, it is 11,400 MW.[24]

2. According to a report prepared for Natural Resources Canada, it is 13,735 MW.[25]

3. According to a report prepared for the Ontario Ministry of Energy, it is 16,514 MW.[26]

This means that Ontario's incremental CHP supply potential is at least 2.8 times greater than the size of the Darlington Nuclear Generating Station (3,512 MW).[27]

Water Power Imports from Quebec

Currently, Ontario's net electricity imports from Quebec are negligible. However, with the completion of a new 1,250 MW interconnection between Quebec and Ontario earlier this year, the total transfer capacity between the two provinces is now 2,788 MW.[28] As a consequence, water power imports from Quebec could displace more than 75% of Darlington's generation capacity without the need for new transmission capacity between Ontario and Quebec.

In 2009 Hydro Quebec exported 23 billion kWh of electricity (mostly to the U.S.) at an average price of 6.5 cents per kWh.[29]

Pursuant to the *National Energy Board Act*, Hydro Quebec must give Ontario an opportunity to purchase electricity on terms and conditions (including price) as favourable as the terms and conditions of its export sales to the U.S. Therefore the latest market data indicates that Ontario could purchase electricity from Quebec at a cost of approximately 6.5 cents per kWh.

Protecting Electricity Consumers from Capital Cost Overruns

In 2004, the Province of Ontario created the Ontario Power Authority (OPA) to promote energy conservation and demand management and to contract for new electricity supplies. To-date the OPA has signed only one contract that allows a power producer to pass its capital cost overruns on to the province's electricity consumers or taxpayers. That contract was a nuclear re-build project.

Renewable and Natural Gas-Fired Electricity Generating Facilities

The OPA has entered into over 400 contracts with individuals, co-ops, First Nations communities, municipal electric utilities and private sector corporations for electricity from wind, water, bioenergy, solar and natural gas-fired power plants.[30] None of these contracts permit the suppliers to pass their capital cost overruns on to Ontario's electricity consumers or taxpayers.

Bruce A Units 1 & 2 Re-Start Project

On October 17, 2005 the OPA signed a contract with Bruce Power for the re-start of the Bruce A Nuclear Generating Station's Units 1 & 2 reactors at a forecast cost of $2.75 billion. According to the October 2005 contract, if Bruce Power has capital cost overruns, it can pass 25-50% of these extra costs on to the OPA.[31]

Approximate Costs of Ontario's Electricity Resource Options

Energy Efficiency	Combined Heat and Power	Water Power Imports from Quebec	Darlington Re-Build
2.3 to 4.6 cents per kWh	5.7 to 6.0 cents per kWh	6.5 cents per kWh	19 to 37 cents per kWh

On April 18, 2008 the *Toronto Star* reported that the Bruce A Units 1 & 2 re-start was $300 to $650 million over budget.[32]

On July 6, 2009 when George Smitherman was Minister of Energy & Infrastructure, the Bruce Power contract was amended to cap the cost overruns that can be passed on to Ontario's electricity consumers at $3.4 billion.[33]

Darlington New Build Competitive Procurement Process

On March 7, 2008, Ontario's then Minister of Energy, Gerry Phillips, announced that Ontario was proceeding with a competitive procurement process for the construction of two new nuclear reactors at the Darlington Nuclear Generating Station. Minister Phillips invited four companies to submit bids: Areva, Atomic Energy of Canada Limited (AECL), GE Hitachi Nuclear Energy and Westinghouse Electric Company.[34]

As of June 16, 2008, according to the Government's proposed procurement process, the successful bidder would **not** be required to submit a fixed price bid for building the two new nuclear reactors. That is, the winning bidder would be allowed to pass on at least some of its capital cost overruns to Ontario's electricity consumers.[35]

On June 20, 2008, George Smitherman became Ontario's Minister of Energy and Infrastructure. Minister Smitherman amended the procurement process to require the bidders to submit a fixed price bid. AECL was the only bidder that "met the province's demand that the vendor assume all the risk for cost overruns."[36] However, AECL's price for building new nuclear reactors, $10,800 per kW, was 3.7 times higher than the Ontario Power Authority forecast of $2,900 per kW.[37] As a consequence, Minister Smitherman suspended the nuclear procurement process and said that Ontario will only proceed with the construction of new nuclear reactors if the Government of Canada will subsidize their cost.[38] To-date Prime Minister Stephen Harper has not responded positively to this request.

Recommendations

1. To protect Ontario's electricity consumers and taxpayers from a capital cost overrun of up to $21 billion or more the Government of Ontario should subject the Darlington Re-Build proposal to the *Level Playing Field Rule* first espoused by George Smitherman. That is, the Government of Ontario should tell Ontario Power Generation (OPG) that it will not be allowed to pass on any capital cost overruns associated with re-building the Darlington Nuclear Generating Station to Ontario's electricity consumers or taxpayers. To proceed with the Darlington Re-Build proposal and to comply with the *Level Playing Field Rule,* OPG must find a third party (e.g., Areva, Atomic Energy of Canada, Bruce Power, General Electric) that will agree to re-build Darlington under a fixed price contract.

2. The Government of Ontario should direct the Ontario Power Authority to aggressively pursue the lower cost and lower risk options to meet our electricity needs. That is, energy efficiency investments, combined heat and power and water power imports from Quebec.

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

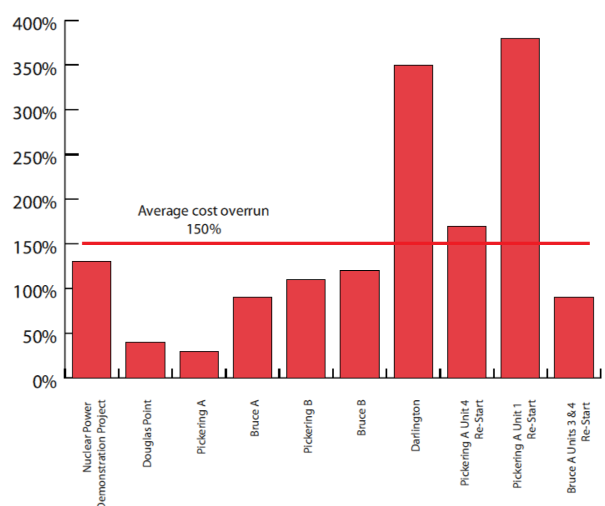
Ontario's History of Nuclear Cost Overruns

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...

Ontario Hydro's Stranded Nuclear Debt

In 1999, as a result of the cost overruns and the poor performance of its nuclear reactors, Ontario Hydro was broken up into five companies. All of its generation assets were transferred to Ontario Power Generation (OPG). In order to keep OPG solvent, $19.4 billion of Ontario Hydro's debt or unfunded liabilities associated with electricity generation facilities was transferred to the Ontario Electricity Financial Corporation (an agency of the Government of Ontario) as "stranded debt" or "unfunded liability".[60]

The defunct Ontario Hydro's nuclear debt costs Ontario's consumers and taxpayers $1.8 billion per year.

The Ontario Electricity Financial Corporation (OEFC) collects revenues from the following sources to help pay off the nuclear stranded debt.

- A debt retirement charge of 0.7 cents per kWh which is levied on all Ontario electricity consumers.
- All of the provincial income tax payments from OPG, Hydro One and Ontario's municipal electric utilities (e.g., Toronto Hydro).
- All of the dividend payments from OPG and Hydro One to their sole shareholder, the Government of Ontario.

In 2009, the sum of the above-noted nuclear debt retirement payments was $1.8 billion.[61] This is equivalent to an annual nuclear debt retirement charge of $137.73 per person in Ontario or $551 for a family of four.[62]

In 2001 the OEFC forecast that the nuclear debt would be fully paid off "in the years ranging from 2010 to 2017".[63] However, as of 2009, the debt has only been reduced by $3.2 billion to $16.2 billion.[64] The OEFC is now forecasting that the debt will be eliminated between 2014 and 2018.[65]

Endnotes

1 Ontario Energy Board Docket No. EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Page 6.

2 Ontario Energy Board Docket No. EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Page 11.

3 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 10, Schedule 014.

4 Ontario Energy Board Docket No. EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Page 10.

5 Ontario Energy Board Docket No. EB-2010-0008, Exhibit JT1.2.

6 Ontario Energy Board Docket No. EB-2010-0008, Exhibit D2, Tab 2, Schedule 1, Pages 4 & 5.

7 Ontario Energy Board Docket No. EB-2010-0008, Undertaking JT1.3.

8 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 10, Schedule 002.

9 Ontario Ministry of Energy, Science and Technology, *Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario*, (November 1997), page 7. The Ontario nuclear industry often claims higher average capacity utilization rates by ignoring the performance of reactors that are temporarily or permanently and pre-maturely shutdown.

10 Email from Carrie Reid, Customer Relations, Independent Electricity System Operator to Jack Gibbons, Ontario Clean Air Alliance, June 24, 2010.

11 OPG Review Committee, *Transforming Ontario's Power Generation Company*, (March 15, 2004), Page 50.

12 Email from Carrie Reid, Customer Relations, Independent Electricity System Operator to Jack Gibbons, Ontario Clean Air Alliance, June 24, 2010.

13 Emails from Carrie Reid and Rebecca Short, Customer Relations, Independent Electricity System Operator to Jack Gibbons, Ontario Clean Air Alliance, July 21, 2010 and September 14, 2010.

14 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 10, Schedule 004.

15 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 6, Schedule 002 and Tab 10, Schedule 002.

16 Letter from CIBC World Markets Inc. to James Gillis, Ontario Deputy Minister of Energy, October 17, 2005.

17 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 10, Schedule 006.

18 According to OPG, assuming 70% equity financing and a required equity rate of return of 18%, the Darlington Re-Build will produce electricity at a total cost of 10 to 14 cents per kWh (assuming an 82% capacity utilization rate) or 12 to 18 cents per kWh (assuming a 64% capacity utilization rate). Furthermore, according to OPG, the Darlington Re-Build's non-capital costs (i.e., operating, maintenance, administration and fuel costs) are 3.9 to 5.2 cents per kWh. All costs are in 2009$. We have increased OPG's estimated capital costs per kWh by a factor of 2.5 to calculate the impact of a 150% capital cost overrun on the Darlington Re-Build's total cost of power. Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 10, Schedules 003 and 006.

19 Ontario Clean Air Alliance, *Conservation vs. Electricity Supply: A summary of the Ontario Power Authority's procurement efforts*, (July 19, 2010).

20 Ontario Power Authority, *Industrial Accelerator Program: Program Rules Version 2.0*, (June 24, 2010), pages 13, 14 & 15.

21 Ontario Power Authority, *Supply Mix Analysis Report*, Volume 2, (December 2005), page 210; and *Integrated Power System Plan*, Exhibit G, Tab2, Schedule 1, page 7.

22 Assuming energy efficiencies of 80 to 90% and an average annual capacity utilization rate of 90%. Ontario Power Authority, *Integrated Power System Plan*, Exhibit I, Tab 31, Schedule 90.

23 Ontario Power Authority, *Integrated Power System Plan*, Exhibit I, Tab 31, Schedule 21, page 1.

24 *Integrated Power System Plan*, Exhibit L, Tab 8, Schedule 7: Thomas R. Casten, Recycled Energy Development LLC, *The Role of Recycled Energy and Combined Heat and Power (CHP) in Ontario's Electricity Future*, page 3.

25 Catherine Strickland & John Nyboer, MK Jaccard and Associates, *Cogeneration Potential in Canada: Phase 2*, (April 2002), page 30.

26 Hagler Bailly Canada, *Potential for Cogeneration in Ontario: Final Report*, (August 2000), page 25.

27 Ontario Power Generation, *Sustainable Development Report 2009*, page 46.

28 Ontario Energy Board Docket No. EB-2008-0272, Exhibit I, Tab 5, Schedule 6.

29 Hydro Quebec, *Annual Report 2009: Shaping The Future*, page 53.

30 Ontario Power Authority, *A Progress Report On Electricity Supply: First Quarter 2010*, pages 6, 24 & 25.

31 Steve Erwin, "Bruce nuclear cost overruns will fall in taxpayers' laps: critics", *Brockville Recorder and Times*, October 18, 2005.

32 Tyler Hamilton, "Reactor repairs confirmed over budget", *Toronto Star*, April 18, 2008.

33 *Second Amending Agreement to the Bruce Power Refurbishment Implementation Agreement Between Bruce Power L.P. and Bruce Power A L.P. and Ontario Power Authority*, July 6, 2009. Available online at: www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=891.

34 Ontario Ministry of Energy, *News Release*, "Ontario Takes Next Step To Ensure Clean, Affordable And Reliable Energy Supply For Generations To Come", (March 7, 2008).

35 According to the Government's news release, "The competitive process will help to ensure the greatest amount of cost certainty, lowest possible price and a fair approach to risk sharing." See Infrastructure Ontario, *Backgrounder*, "Nuclear Procurement Project Phase 2", (June 16, 2008).

36 Shawn McCarthy & Karen Howlett, "Ontario's move puts AECL's future in doubt", *Globe and Mail*, (June 30, 2009).

37 Tyler Hamilton, "Nuclear bid rejected for 26 billion reasons: Ontario ditched plan for new reactors over high price tag that would wipe out 20-year budget", *Toronto Star*, (July 14, 2009).

38 Romina Maurino, "Province puts nuke plans on hold", *Toronto Sun*, (June 30, 2009); and Susan Riley, "Nuclear summer", *Ottawa Citizen*, (July 31, 2009).

39 G. Bruce Doern, *Government Intervention in the Canadian Nuclear Industry*, (The Institute for Research on Public Policy, 1980), page 104.

40 The Hydro-Electric Power Commission of Ontario, *Annual Report 1962*, page 60.

41 *Government Intervention in the Canadian Nuclear Industry*, page 107.

42 Paul McKay, *Electric Empire: The Inside Story of Ontario Hydro*, (Between The Lines, 1983), page 59.

43 The Hydro-Electric Power Commission of Ontario, *Annual Report 1967*, page 57.

44 Letter from Rosemary C. Watson, Manager, Corporate Records & Freedom of Information, Ontario Power Generation to Jack Gibbons, Ontario Clean Air Alliance, July 19, 2010.

45 The Hydro-Electric Power Commission of Ontario, *Annual Report 1969*, page 34.

46 Letter from Rosemary C. Watson, Manager, Corporate Records & Freedom of Information, Ontario Power Generation to Jack Gibbons, Ontario Clean Air Alliance, July 19, 2010.

47 Ontario Hydro, *Annual Report 1975*, page 4.

48 Letter from Rosemary C. Watson, Manager, Corporate Records & Freedom of Information, Ontario Power Generation to Jack Gibbons, Ontario Clean Air Alliance, July 19, 2010.

49 Ontario Hydro, *Annual Report 1975*, page 4.

50 Letter from Rosemary C. Watson, Manager, Corporate Records & Freedom of Information, Ontario Power Generation to Jack Gibbons, Ontario Clean Air Alliance, July 19, 2010.

51 Ontario Hydro, *Annual Report 1975*, page 4.

52 Letter from Rosemary C. Watson, Freedom of Information Coordinator, Ontario Power Generation to Ravi Mark Singh, Ontario Clean Air Alliance, April 27, 2004.

53 *Report of the Pickering "A" Review Panel*, (December 2003), page 4.

54 *Report of the Pickering "A" Review Panel*, (December 2003), page 4.

55 *Report of the Pickering "A" Review Panel*, (December 2003), page 3.

56 OPG, *News from Ontario Power Generation*, "Ontario Power Generation Reports 2005 Third Quarter Financial Results", (November 11, 2005).

57 OPG, *News Release*, "OPG Moves to Planning Phase of Darlington Refurbishment", (February 16, 2010).

58 Letter to James Gillis, Ontario Deputy Minister of Energy from CIBC World Markets Inc., October 17, 2005.

59 Ontario Energy Board Docket No. EB-2010-0008, Exhibit L, Tab 2, Schedule 015.

60 Ontario Electricity Financial Corporation, *Annual Report: April 1, 1999 to March 31, 2000*, page 8.

61 Ontario Electricity Financial Corporation, *Annual Report 2009*, page 12.

62 Ontario's population in 2009 was 13,069,200.

63 Ontario Electricity Financial Corporation, *Annual Report 2001*, page 29.

64 Ontario Electricity Financial Corporation, *Annual Report 2009*, page 11.

65 Ontario Electricity Financial Corporation, *Annual Report 2009*, page 20.

66. According to the NB Power Group's *2007/08 Annual Report*, total construction costs, excluding replacement fuel and purchased power costs, would be approximately $1 billion (see page 20). According to recent reports, the project is approximately $1 billion over budget. See Chris Morris, "Leaders spar over Lepreau", *Telegraph-Journal*, (August 23, 2010).

Filed: 2010-08-17
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Issue 6.11
Exhibit L
Tab 2
Schedule 026
Page 1 of 1

AMPCO Interrogatory #026
(NON-CONFIDENTIAL VERSION)

Ref: Ex. F2-T2-S3, page 4

Issue Number: 6.11
Issue: Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes appropriate?

Interrogatory

Please provide the analysis presented to the Board of Directors that lead OPG to decide to not refurbish Pickering B.

Response

See the response in Ex. L-01-070 for factors that contributed to the decision not to refurbish Pickering B Generating Station.

A copy of the requested analysis is provided in the confidential attachment (Attachment 1).

UPDATE ON THE PICKERING B REFURBISHMENT PROJECT

The following table summarizes the key post-refurbishment costs and performance assumptions used in the feasibility assessment.

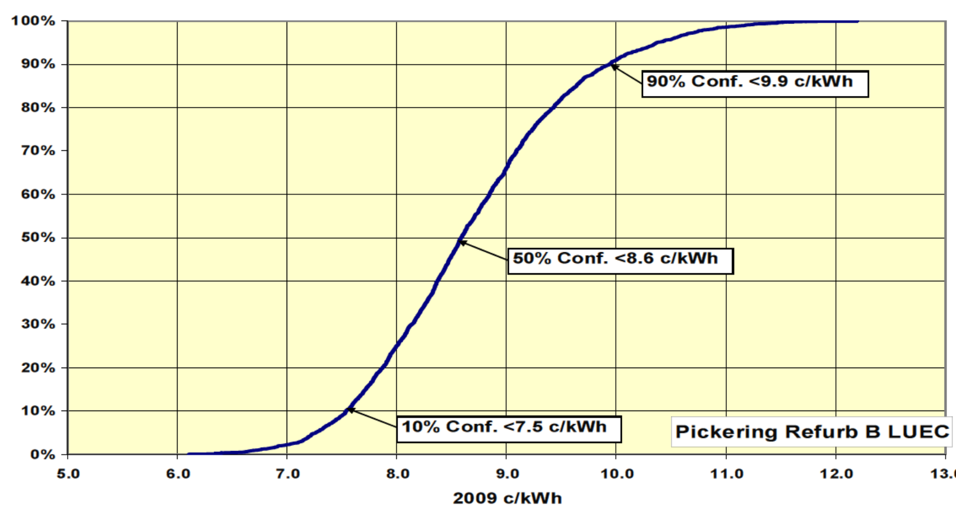
Post-Refurbishment Operations High Confidence Estimates	Average Cost / Unit (Overnight $M 2009)	Comments
Annual Direct Station Costs Post-Refurbishment	130	Current 2008-2010 Business Plan Avg. is $102M. The $130 M used is adjusted for historical average spending on projects and is OPG's high confidence estimate.
Annual Support Costs Post-Refurbishment (1)	30	Consistent with 2008 Business Plan adjusted for high confidence. Incremental analysis performed by OPG personnel
Plant Performance Post Refurbishment	75%	Lifetime performance is 77%; including strikes, management shutdowns, major outages for SLAR, etc. Range of 75% to 85% used. Bottom-up detailed forecast for post-refurbishment period is 84%

(1) The Annual Support Costs shown are the incremental costs of Corporate and Nuclear Support

Based on these inputs, the expected high confidence Levelized Unit Energy Cost (LUEC) for refurbishment of Pickering B, and continued operation for a period of 30 years after refurbishment, is estimated to be approximately 9.9 ¢/kWh (2009$). The high confidence estimated cost for the refurbishment project is [redacted] (overnight 2009$) which includes a total contingency amount of [redacted] The contingency amount of [redacted] includes [redacted] to cover potential costs of major regulatory upgrades required beyond those already included in the base scope of work.

The project uncertainties and future performance have been analyzed in a Monte Carlo analysis resulting in a LUEC range of 7.5 ¢/kWh (low confidence) to 9.9¢/kWh (high confidence). At a medium confidence level the LUEC is 8.6 ¢/kWh.

Figure 1: LUEC Range for Pickering B Refurbishment



4. Continued Operation Of Pickering B

During the initial development of the Pickering B Feasibility Assessment in 2007, it became apparent that there is an opportunity to continue to operate the Pickering B units by 4 years or more beyond their current nominal operating lives of 2014/2016 by taking actions to maximize pressure tube life. Management developed a comprehensive work plan to explore and develop the Continued Operation option, i.e. to take the actions necessary to safely and reliably operate Pickering B for an additional

Board Staff Interrogatory #070

Ref: Ex. F2-T2-S3, page 4

Issue Number: 6.7
Issue: Are the proposed expenditures related to continued operations at Pickering B appropriate?

Interrogatory

The application notes on page 4 that OPG has decided to pursue the continued operation work program on Pickering B rather than refurbish Pickering B and the major factors in this decision included "the economics of the Pickering B refurbishment". Please elaborate on the reasons for the decision against refurbishment of Pickering B, particularly the factor noted above.

Response

The refurbishment scope associated with Pickering B Generating Station included replacement of fuel channels, feeders, and steam generators. A decision to refurbish Pickering B Generating Station in the mid-2010 timeframe would have resulted in an overlap with the Darlington Generating Station refurbishment and other potential nuclear refurbishments in the province. Significant risks to the success of these projects were foreseen if multiple refurbishments were pursued, including project management and overall resource availability. These risks, as well as the factors listed below, all contributed to the decision not to refurbish Pickering B Generating Station.

Other factors included:

- the economic benefit of the Continued Operations of Pickering B Generating Station.
- the lead time required to procure steam generators for Pickering B Generating Station.
- the need to manage the overall availability of OPG's nuclear fleet during the period following the shutdown of OPG's coal-fired units and during the period when major nuclear refurbishments are expected to be executed in the province.
- uncertainty that Pickering B Generating Station would be able to achieve an additional 25 to 30 years operation (Pickering B Generating Station is approximately a decade older than the Darlington Generating Station units)

Given these significant risks (which, if realized, could affect the economics of Pickering B Refurbishment), and the fact that another feasible option (Continued Operations) was available for Pickering B Generating Station, the decision was made not to pursue Pickering B Refurbishment.

EB-2010-0008 Technical Conference Transcript, August 26, 2010:

And if I could ask parties to then turn to page 29 of the compendium relating to questions posed by Pollution Probe, in the first Pollution Probe, No. 1, relating to Issue 2.2, dealing with the capital costs of 6 billion to 10 billion for Darlington.

MR. REINER: This question asks for what that $6 billion to $10 billion overnight capital cost translates to when capitalized interest during construction is included.

So when we include capitalized interest and escalation due to inflation, the 6 billion translates to 8.5 billion, and the 10 billion translates to 14 billion.

MR. ALEXANDER: Do you have those numbers for just the capitalized interest?

MR. REINER: I don't have that with me at this point.

MR. ALEXANDER: Can you undertake to provide that?

MR. REINER: We could provide that, yes.

MS. BINNETT: That is Undertaking JT1.2.

UNDERTAKING NO. JT1.2: TO PROVIDE NUMBERS FOR CAPITALIZED INTEREST DURING DARLINGTON CONSTRUCTION.

MR. KEIZER: Then I believe that is the only nuclear question from Pollution Probe.

Moving on, then, to page 31 of the compendium relating to questions posed by Power Workers' Union, this is PWU question No. 2, which relates to OPG's project management approach.

MR. REINER: So this question asks how OPG's project management approach will be applied in entering into some