ONTARIO ENERGY BOARD

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.

ENVIRONMENTAL DEFENCE'S
CROSS-EXAMINATION DOCUMENT BOOK – PANEL 8

July 14, 2014

KLIPPENSTEINS
Barristers & Solicitors
160 John Street, Suite 300
Toronto, Ontario M5V 2E5

Murray Klippenstein
Kent Elson
Tel: (416) 598-0288
Fax: (416) 598-9520

Lawyers for Environmental Defence

Index

Note: Some of the above are excerpts of the relevant document.

[1] http://www.theimo.com/imoweb/historical_devel/finale.pdf

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

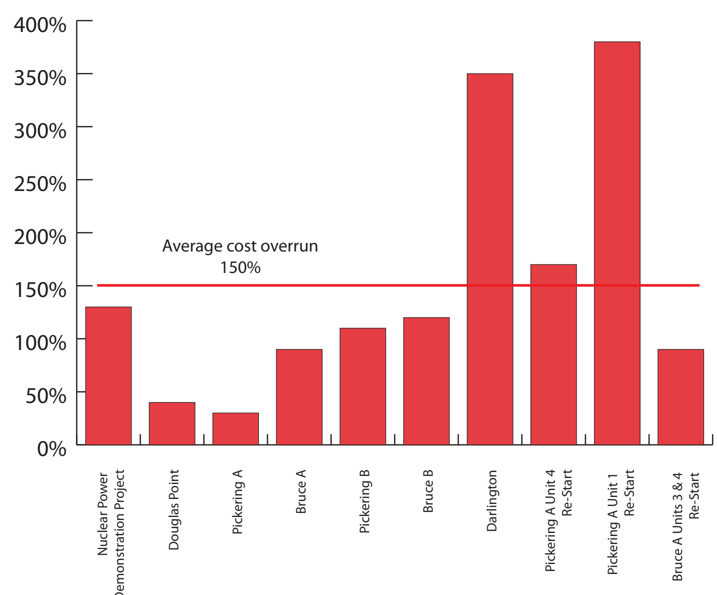
Ontario's History of Nuclear Cost Overruns

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).

ONTARIO
CLEAN AIR
ALLIANCE

Ontario Clean Air Alliance Research Inc.
625 Church Street, Suite 402
Toronto M4Y 2G1
Tel: (416) 926-1907 ext. 246
Fax: (416) 926-1601
E-mail: contact@cleanairalliance.org
Web Site: www.cleanairalliance.org

ED Interrogatory #014

Ref: Appendix A of *The Darlington Re-Build Consumer Protection Plan* (attached)

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

Appendix A of *The Darlington Re-Build Consumer Protection Plan* (attached) provides the original cost forecasts and the actual costs of Ontario's nuclear projects. Does OPG dispute the accuracy of any of the facts provided in this Appendix? If "yes", please state the facts that OPG disputes and provide OPG's opinion as to the correct value(s).

Response

In response to EB-2013-0321, Decision and Order on Motions, dated May 16, 2014, OPG was asked to respond to the question "Does OPG have any basis/evidence to dispute the information contained in the Clean Air Alliance Report, Appendix A page 17, with respect to cost overruns?"

OPG has done a partial validation of the references cited in Appendix A, page 17, of the Clean Air Alliance Report. While OPG believes that the references are correctly cited, to the extent of its review, it is OPG's opinion that in certain cases, the report fails to provide certain critical information that properly sets the context of the cost increases.

As an example, the report cites that in 1999 OPG estimated the total cost of returning the shutdown Pickering A Unit 1 to service would be $213 million. The reference further cites that the actual cost was 4.8 times higher at $1.016 billion. The reference fails to recognize that 1) the original estimate was made prior to detailed planning and completion of engineering, and 2) the project was approved by OPG's Board of Director's in July 2004 with a project estimate of $900 Million. The actual cost of the project was $1,016 Million, a 12.9% cost growth including project demobilization based on a decision not to restart Units 3 and 4.

REPORT
of the
PICKERING "A" REVIEW PANEL

December 2003

Pickering Review Panel

The Citadel
Suite 830, 1075 Bay St.
Toronto, Ontario, M5S 2B1
Telephone: (416) 212-4477

Hon. Jake Epp, P.C., BA., B.Ed.LL.D (Hon.)
Peter Barnes
Dr Robin Jeffrey FREng

November 30, 2003

The Honourable Dwight Duncan, MPP
Minister of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario

Dear Minister:

The Pickering "A" Review Panel has the honour of presenting our report to you in accordance with the terms of reference set out for the review in May 2003.

We would like to express appreciation to the participants who contributed to our understanding of the many, complex issues associated with the Pickering "A" return to service project. The Panel would also like to acknowledge the cooperation provided by officials from Ontario Power Generation.

Finally, we wish to thank the staff from the Ontario Financing Authority of the Ministry of Finance and Ministry of Energy for the assistance they provided to the Panel over the course of its review.

Respectfully submitted,

Jake Epp

The Honourable Jake Epp
Chair

Peter Barnes

RC Jeffrey
Dr. Robin Jeffrey

REPORT of the PICKERING "A" REVIEW PANEL

December 2003

Introduction

In late September 2003, the first of four Pickering A reactors (designated Unit 4) returned to service. Compared with the plan approved by the Board of Directors of Ontario Power Generation, Inc. (OPG) in August 1999, the cost for Unit 4 return to service had almost tripled, and the return to service date had slipped by more than two years.

These facts are alarming, but they are not the only price paid. The delay in the return to service of Pickering A has adversely affected Ontario's electricity sector and pushed up prices for residential and business consumers. The costs and delays of the project have also reduced OPG's revenues, capital resources and corporate value. But perhaps most seriously, faith has been compromised in the affordability and certainty of the supply of electricity vital to Ontario's citizens and businesses.

While the analysis of what went wrong provides a catalogue of problems, ultimate responsibility must lie with the OPG Board and senior management and how they exercised their oversight responsibilities.

The failings of the Unit 4 restart execution have been recognized by OPG, and over the past few months, more appropriate project management and oversight arrangements have been put in place.

The Panel considers it imperative that the decision on whether to continue with the restart of the remaining units be made as soon as possible. To make this decision, OPG must provide the Government and the Minister of Energy with a firm estimate of cost and timelines for completion.

This report sets out the findings and recommendations of the Review Panel's investigation.

Mandate and Scope

The Pickering "A" Review Panel was established at the end of May 2003 with the following terms of reference:

- Determine the reasons and reasonableness of the changes in the schedule and return to service dates.
- Determine the reasons and reasonableness of cost estimates and cost increases.
- Review the financial reporting for project costs.
- Make recommendations to the Minister on means of improving the management of the project to restore the Pickering A Generating Station to full operation, including measures to ensure the cost-effective and timely completion of the project.

The Panel began its work in June 2003 and has:

- Held more than 40 days of working sessions.
- Reviewed over 300 documents including key reports, management memoranda, submissions to the OPG Board, internal project reviews, and an external study on performance metrics.
- Met with members of the OPG Board of Directors.
- Interviewed senior OPG executives and a number of current and former Pickering A project managers.
- Met with the leadership of the Power Workers' Union and the Society of Energy Professionals.
- Met with senior staff from two main contractors:
  - Atomic Energy of Canada Limited (AECL), the federal Crown corporation that acted as an independent consulting engineer to OPG; and
  - Canadian Nuclear Engineers and Constructors (CANEC), the joint venture that was initially involved as the general contractor and project director.[1]
- Discussed the project and the regulatory process with officials from the Canadian Nuclear Safety Commission (CNSC).
- Received presentations from Schiff, Hardin & Waite, a U.S. firm with expertise in construction law.[2]
- Visited the Pickering A Generating Station to review and discuss the project.

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1 CANEC was formed for this project in June 1999 as a joint venture of Stone & Webster of Canada L.P., Comstock Canada Ltd., and Canatom NPM/BFC Industrial.

2 OPG retained Schiff, Hardin & Waite in March 2003 to undertake an independent review and root-cause analysis audit to determine the reasons for the problems encountered with Unit 4 and identify key lessons learned from Unit 4 applicable to the return of the remaining units. Schiff, Hardin & Waite were assisted by J. Wilson & Associates and by Myer Construction Consulting.

Then and Now

In January 1997, Ontario Hydro, the predecessor to OPG, commissioned an Independent, Integrated Performance Assessment (IIPA) of Ontario's nuclear plants. The IIPA pointed out shortcomings in performance and concluded that the performance of Ontario's stations was well below that being achieved by the world's best nuclear stations.

Shortly after the release of the IIPA, Ontario Hydro endorsed a plan that included the temporary lay-up of the four units at Pickering A and the three operating units at Bruce A so that resources could be focussed on upgrades to the remaining operating units at Bruce B, Pickering B and Darlington. In addition to declining performance, the decision to lay up the Pickering A station also reflected the fact that the federal nuclear regulator, the Atomic Energy Control Board (AECB),[3] had earlier established that the station could not operate after the end of 1997 without enhancements to its shutdown system.

The four units at Pickering A were laid up by the end of 1997 and the three at Bruce A by May 1998. A major difference between these two lay-ups was the decision to remove the fuel in the reactors at Bruce A, but leave the fuel in the Pickering A reactors, reflecting management's view that Pickering A would be returned to service sooner than Bruce A.

The Ontario Hydro Board of Directors approved work supporting the restart of all four units at Pickering A in August 1997, based on a budget of $780 million and an expectation that the first unit would return to service in June 2000. This estimate was revised in May 1999 to $840 million to reflect increased labour costs.[4]

The August 1999 approval to proceed by the Board of Directors of the newly created OPG was based on a total project cost of $1.1 billion with the following breakdown by unit: $457 million for Unit 4 and systems common to all four units, $213 million for Unit 1, $219 million for Unit 2, and $211 million for Unit 3.

When Pickering A Unit 4 returned to commercial service at the end of September 2003, the costs had nearly tripled from the $457 million estimate, and the return to service was more than two years behind the August 1999 schedule.

Three units remain out of service. OPG did not provide to the Panel an estimate for the cost of returning all four units to service. All that was made available was a range of estimates they had

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3 The Atomic Energy Control Board was the predecessor to the Canadian Nuclear Safety Commission, which came into being on May 31, 2000.

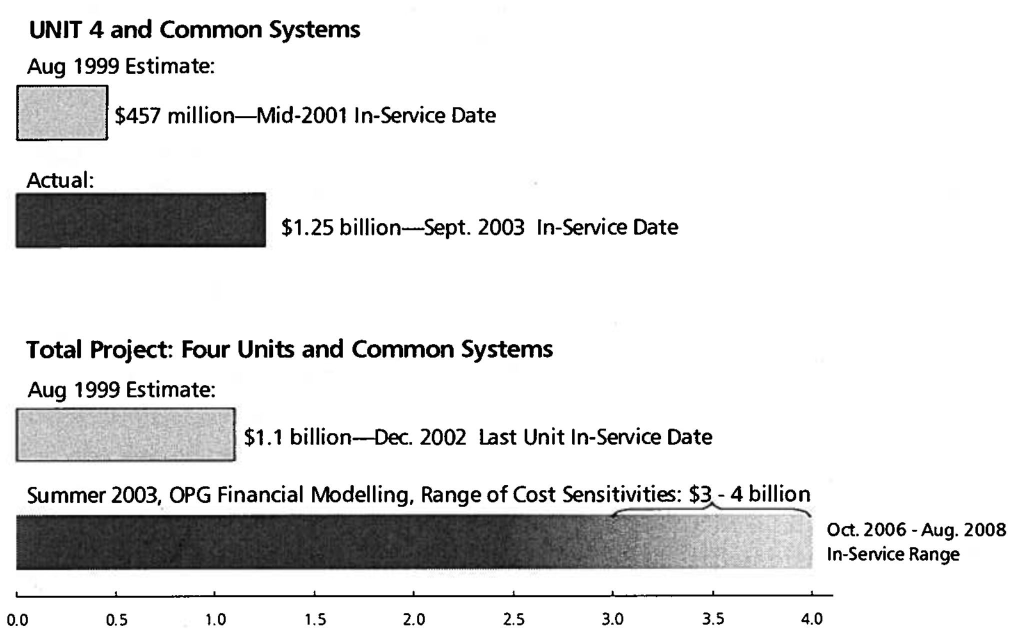
4 Neither of these early estimates included the costs of operations, maintenance and administration (OM&A) during the start-up phase. Starting from August 1999, estimates reported by OPG included an estimated cost for pre-start-up OM&A of $200 million.

prepared for financial modelling purposes of $3 to $4 billion. Timelines for completion of the last unit range from October 2006 to August 2008.

OPG is currently undertaking some physical work on Unit 1, as well as completing design engineering, planning and assessing, and verifying detailed estimates by contractors. It is understood that in early 2004, OPG will present to its Board a detailed cost estimate for returning Unit 1 to service. Given that the current expenditure on the remaining three reactors is about $25 million per month, it is critical that a decision on whether to continue with the return to service of additional units be made as soon as possible.

Figure 1 below highlights the degree to which costs have escalated and schedules have extended beyond the original plan.

Figure 1. Time and Cost Estimates



ONTARIOPOWER GENERATION

News
from Ontario Power Generation

700 University Avenue Toronto, Ontario M5G 1X6

Tel: 416-592-4008 or 1-877-592-4008 Fax: 416-592-2178
www.opg.com

November 11, 2005

ONTARIO POWER GENERATION REPORTS 2005 THIRD QUARTER FINANCIAL RESULTS

[Toronto]: Ontario Power Generation Inc. ("OPG" or the "Company") today reported its financial and operating results for the third quarter and nine months ended September 30, 2005. Net income for the three months ended September 30, 2005 was $181 million or $0.71 per share compared to a net loss of $15 million or $0.06 per share for the same period in 2004. For the nine months ended September 30, 2005, net income was $206 million or $0.80 per share compared to $8 million or $0.03 per share for the same period last year.

Effective April 1, 2005, the output from OPG's baseload hydroelectric and nuclear facilities became rate regulated, while output from its remaining hydroelectric facilities, and its fossil-fuelled and wind generating stations remain unregulated. However, the majority of the generation output from these unregulated facilities is subject to a revenue limit of 4.7¢/kWh to April 30, 2006. As a result of these changes and higher average Ontario spot market prices due to a prolonged period of high temperatures in the June to September time frame and the impact of higher natural gas prices, OPG received average prices of 5.4¢/kWh and 4.9¢/kWh respectively for the output from all of its generating facilities during the three and nine months ended September 30, 2005. While this was an increase compared to OPG's realized average prices of 4.0¢/kWh and 4.2¢/kWh for the same periods last year, it was considerably less than the average hourly Ontario electricity prices (HOEP) of 8.6¢/kWh and 6.7¢/kWh for the three and nine month periods in 2005.

"Our third quarter financial results reflect higher realized electricity prices as well as increased production, compared to the third quarter of 2004. In particular, our fossil stations responded to record setting Ontario energy demand by producing 45 per cent more electricity than in the third quarter of 2004. Our year-to-date 2005 earnings exceed 2004 earnings for the same period and we expect this trend to continue to the end of 2005," said President and CEO Jim Hankinson.

Electricity production during the three months ended September 30, 2005 from OPG's generating stations was 27.1 TWh compared to 26.0 TWh during the same period in 2004. The increase in generation was primarily a result of significantly higher fossil-fuelled generation attributable to higher electricity demand especially during a period of record high temperatures in the third quarter of 2005.

FINAN

For the nine months ended September 30, 2005, total production from OPG's generating stations was 81.4 TWh compared to 78.9 TWh for the same period in 2004. The increase in generation was primarily a result of higher fossil-fuelled generation in 2005, due to higher electricity demand and improved station performance, and higher nuclear generation due to improved station performance at OPG's Pickering B and Darlington generating stations. Hydroelectric generation during the first nine months of 2005 has been negatively impacted by lower water levels.

OPG's third quarter earnings were favourably impacted by an increase in gross margin from electricity sales primarily due to higher average sales prices during the third quarter of 2005 compared to the same period in 2004. Earnings were also favourably impacted by the establishment of a deferral account for non-capital costs related to the Pickering A nuclear generating station return to service project as required by a regulation pursuant to the *Electricity Restructuring Act, 2004.*

Earnings during the nine months ended September 30, 2005 were favourably impacted by an increase in gross margin during 2005 primarily as a result of higher average sales prices due to higher temperatures in the June to September period, higher nuclear and fossil generation, and the deferral of non-capital costs related to the Pickering A return to service project commencing in 2005. These favourable impacts were partly offset by an impairment loss on OPG's Lennox generating station recorded during the first quarter of 2005, and the impairment loss on Units 2 and 3 of the Pickering A nuclear generating station, recorded during the second quarter of 2005. In addition, earnings were impacted by higher nuclear maintenance and repairs related to continuing improvements in station reliability, and a one-time extraordinary loss to reflect the impact of adopting rate regulated accounting for income taxes effective April 1, 2005.

In August 2005, following consideration of the costs and risks associated with returning Units 2 and 3 of the Pickering A nuclear generating station to service, and taking into account the Company's current focus on improving the performance of its operating nuclear units, OPG's Board of Directors decided that while technically feasible, the return to service of these units was not justified on a commercial basis. Accordingly, an impairment loss representing the carrying value of these units was recorded in OPG's second quarter results. Units 2 and 3 have been maintained in a safe shutdown state since December 1997. Over the next two years, the fuel and heavy water will be removed from the units.

1.01b

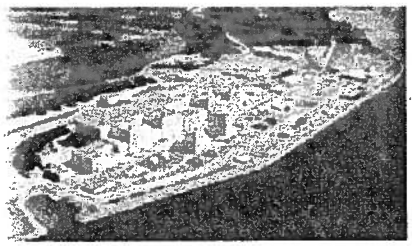
On September 26, 2005, Unit 1 at the Pickering A nuclear station was synchronized to the provincial electricity grid, sending electricity from the unit to Ontario consumers for the first time since December 1997. The unit was declared to be commercially available on November 3, 2005. Total costs incurred up to November 3, 2005 were $996 million, excluding the impact on costs of feeder inspections and replacement of $20 million, which were not included in the original scope of the project. The project represented a complex management and construction challenge, encompassing more that 1.9 million hours of work and almost 3,000 people at its peak. "The culmination of this project represents an outstanding achievement for OPG," said President and CEO Jim Hankinson.

OPG Moves to Planning Phase of Darlington Refurbishment

Pickering B to Enter Final Decade of Operation with $300-Million Investment

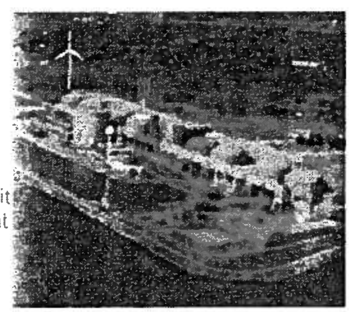
Feb. 16, 2010

Durham Region – Today, Ontario Power Generation (OPG) announced a two-part investment strategy for its nuclear generating stations in Durham Region.



First, OPG will proceed with a detailed planning phase for the mid-life refurbishment of the Darlington Nuclear Generating Station east of Toronto, with construction expected to start in about 2016. The business decision to move forward with an investment in Darlington comes after very positive outcomes of initial studies on the plant's condition and continued strong operating performance. The next phase of the process will include an Environmental Assessment, an Integrated Safety Review and an Integrated Improvement Plan that will define the scope, cost and schedule of the refurbishment project.

OPG will also invest $300 million to ensure the continued safe and reliable performance of its Pickering B station for approximately 10 years. Following this, OPG will begin the longer term decommissioning process as refurbishment for Pickering B station will not be pursued. The first step in this process is to layup the reactors and place them into safe storage. Pickering staff will have future opportunities placing the Pickering units in a safe storage state, at the Darlington refurbishment and operations, or at the potential new build at Darlington.



Extensive safety, environmental and equipment reliability studies conducted at the station concluded the Pickering plant can continue to operate safely and reliably to meet the province's energy needs through to 2020. OPG has indicated to the Canadian Nuclear Safety Commission that later this year it will file a Continued Operation Plan that takes Pickering B to its end of life.

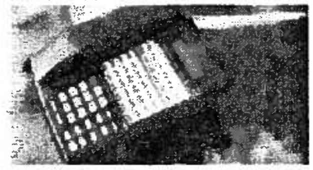
"As Ontario's generating company, OPG's nuclear and hydro fleets are the backbone of the provincial electricity system," said Brad Duguid, Minister of Energy and Infrastructure. "I support this business investment strategy as it aligns with the government's vision for a clean energy future. It is also respectful of employees and it will ensure continued economic benefits to the people of Durham Region and Ontario."

"OPG is committed to continued business investment in Durham Region to meet the electricity production needs of Ontarians," said Tom Mitchell, OPG's President and CEO. "Investing in refurbishment at Darlington and continuing operation at Pickering B provide the best value for the people of Ontario."

"The key to a successful refurbishment is having a clear understanding of the scope and cost of the work we need to do well before we start construction," said Bill Robinson, Executive Vice President Nuclear Projects."

In planning the Darlington refurbishment, OPG will build on the accomplishments and lessons learned during the Pickering A restart and the Pickering safe storage project. The restart of Pickering Unit 1 was completed on time and on budget, and the safe storage project for Units 2 and 3 is currently tracking on budget and on time for completion this year.

More Info



Our phone lines are open to answer questions.

- 1-800-461-0034 Darlington Public Info
- 905-837-7272 Pickering Public Info
- 1-877-592-4008 Media

Darlington Nuclear Backgrounders

- **Project Management Principles**
- **Components of a CANDU Refurbishment**
- **Frequently Asked Questions**

Pickering Nuclear Backgrounders

- **Continued Operations**
- **Summary of Safety and Environment Studies**
  - **Environmental Assessment**
  - **Integrated Safety Review**
- **Service History**
- **Summary Timeline**

continued at the Bruce Nuclear Power Development, Lennox, Pickering, Thunder Bay, Wesleyville, Arnprior and Nanticoke.

The presently authorized capital construction program will add about 14,000,000 kilowatts to Ontario Hydro's generating capacity by 1985.

However, in July, 1975, the Provincial Treasurer requested that Hydro reduce its capital program, and in January 1976, further restrictions were placed on Ontario's public borrowing. These two actions resulted in a revised capital program affecting 11 major projects and reducing capital expenditures by $6.4 billion through to 1985.

Restraints affect 11 projects

The fourth heavy water plant at the Bruce Nuclear complex was cancelled. This $562 million plant, with a planned capacity of 600 megagrams per year, was scheduled for completion in 1980.

Completion date of the third heavy water plant at Bruce was postponed for two years.

The second Bruce Generating Station, a four-unit, nuclear-powered plant of 3,200,000 kilowatts capacity, had its in-service dates deferred for one year, with the first unit now scheduled to enter service in 1983. Formal approval of the construction schedule of this $2.7 billion plant had been received from the Ministry of Energy on October 8, 1975.

The second steam transformer plant at the Bruce complex, a $206 million project had its completion date postponed one year to 1982.

Pickering "B" Generating Station, a twin to the existing 2,160,000 kilowatt Pickering "A" nuclear station, being built at an estimated cost of $1.8 billion, had its completion date deferred one year with the first of four units now scheduled to be in-service by 1981.

Thunder Bay Generating Station, a two-unit, 300,000 kilowatt coal-fired extension to the existing station costing $345 million, was also postponed one year with completion dates now set at 1980 and 1981.

Atikokan Generating Station, a proposed coal-fired station for which the site purchase had been approved by government in May, 1975, was delayed one year, with in-service dates for the four units now 1983 and 1984.

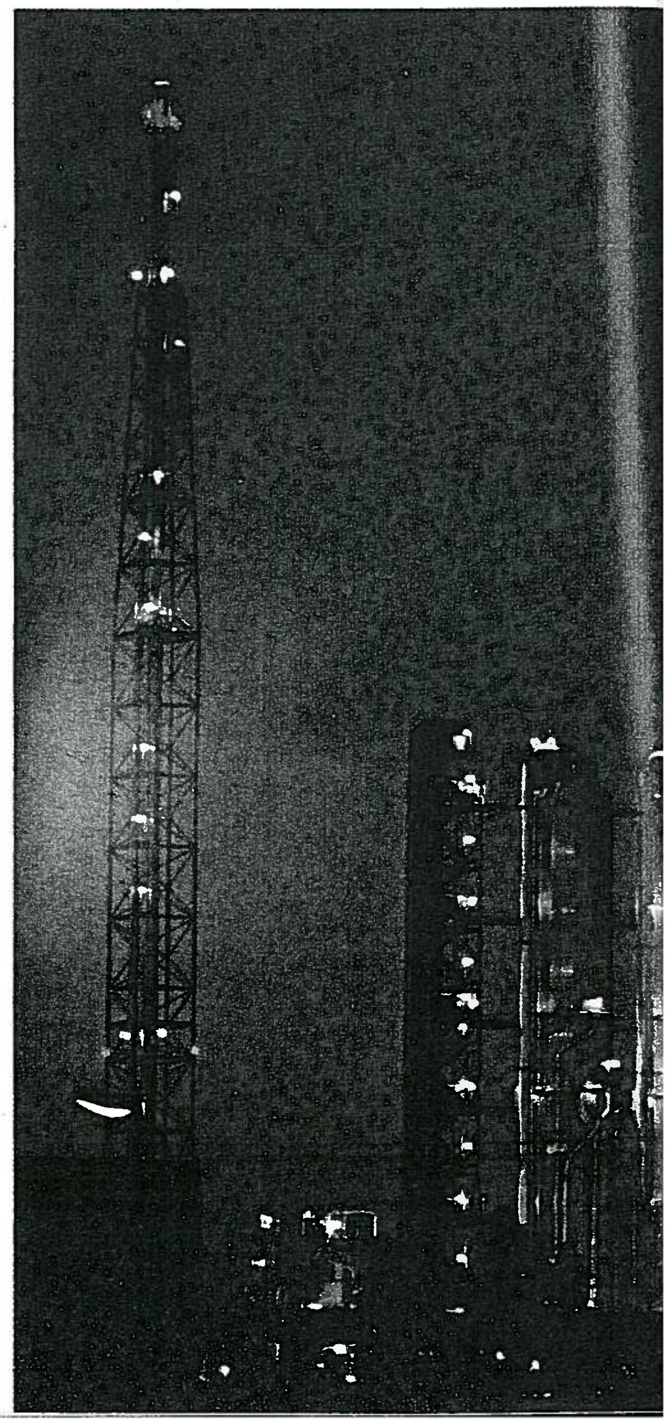
Wesleyville Generating Station, a four-unit oil-fired plant of 2,295,000 kilowatt capacity with an

1982 and 1983.

Darlington Generating Station, a $3.2 billion, four-unit, nuclear plant near Bowmanville, was delayed two years. It will have a capacity of 3,400,000 kilowatts. Formal approval was received in 1975 to proceed with the public participation process for this station. It is now scheduled to begin producing power in 1986.

W-3 Generating Station, a third new power project planned for Northwestern Ontario, was delayed one year with the in-service date for the first unit now 1986.

E-15 Generating Station, was delayed for two years. It is now scheduled for service in 1987. Potential sites for this project are being considered along the North Channel of Lake Huron.



A total of 605 megagrams of heavy water were produced in 1975 at the Bruce heavy water plant, located on the shores of Lake Huron about 120 miles northwest of Toronto.

Ontario Hydro Annual Report 1975

The 4,000,000 kilowatt coal-fired station at Nanticoke, now in partial operation, is scheduled for completion in 1977. With five units now in production, commissioning of Unit 6 is well under way and it should be ready for service by late 1976.

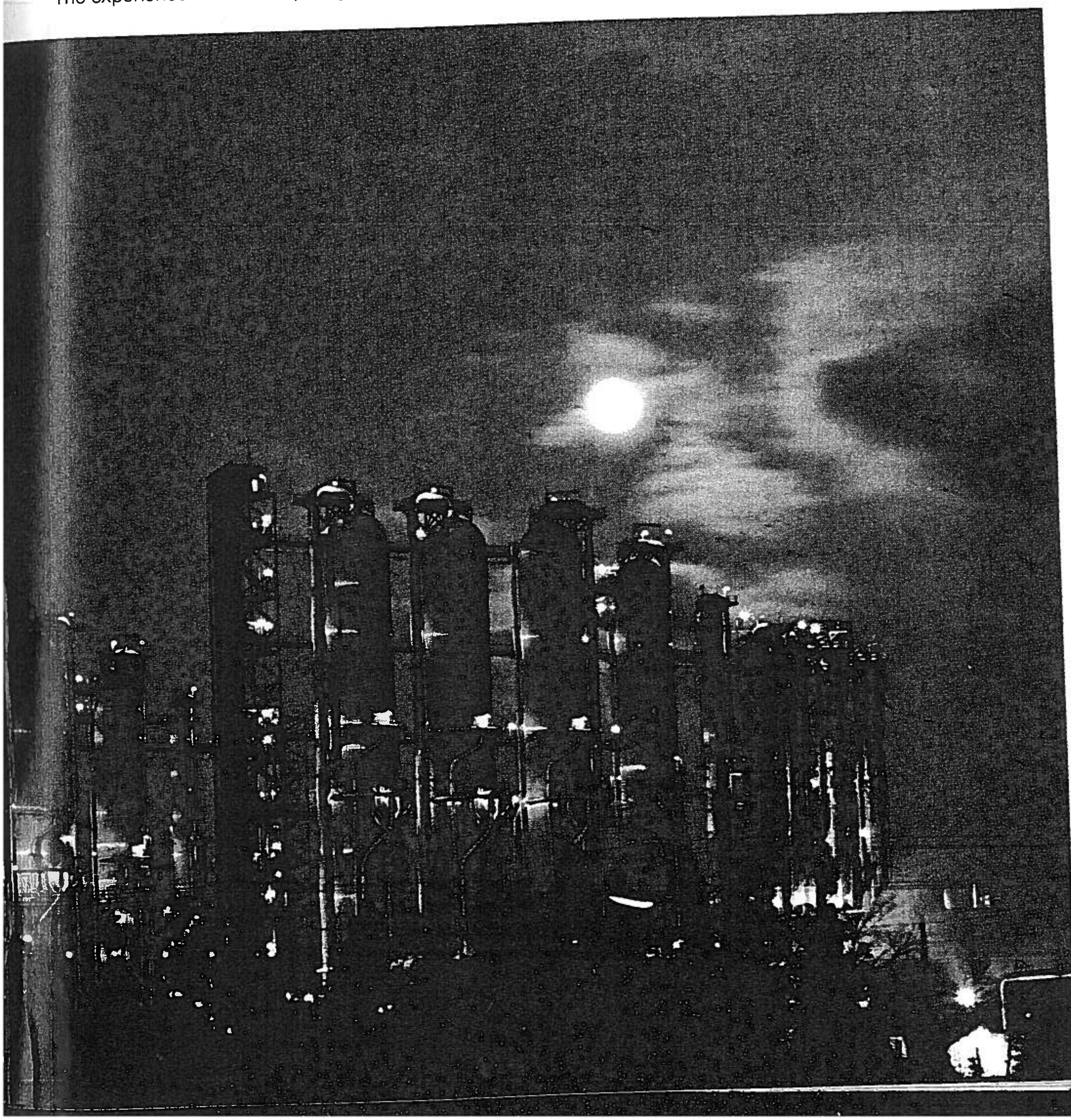
Nanticoke's Unit 2, heavily damaged by fire in 1974, was returned to service in late 1975 after being down for 17 months. The fire was attributed to retaining ring failure and redesigned rings are being installed in all eight units.

At the Pickering nuclear station, where pressure tube leaks were experienced in August 1974, 17 of the 390 pressure tubes in Unit 3 were replaced and the reactor returned to full power by March 1975. Similar problems were subsequently discovered in Unit 4 and by year end replacement of the 57 tubes affected was well under way.

The experience and techniques gained at Pickering by engineers from Hydro, Atomic Energy of Canada Limited and various suppliers were quickly applied to the 3,200,000 kilowatt Bruce "A" nuclear plant, now under construction. The Bruce pressure tubes for units one and two were stress-relieved and design modifications applied. These actions have caused a six-month delay in the station's start-up date, and it is now expected to be fully operational by 1979.

At the Arnprior generating station, construction work on two hydro-electric units, with a total capacity of 78,000 kilowatts, is scheduled for completion in 1976.

The first unit at Lennox Generating Station, Ontario's first oil-fired station, entered service in January, 1976 and all four units at the 2,295,000-kilowatt plant are scheduled for service by 1977. Regular shipments of residual oil from Quebec City are now arriving at Lennox by unit train.



ONTARIOPOWER GENERATION

700 University Avenue Toronto, Ontario M5G 1X6

April 1, 2004

Re: Request Number 040042
Final and Total Capital Cost of the Darlington Nuclear Generating Station

This document has been prepared in response to a request dated March 11, 2004 regarding the final and total capital cost of the Darlington Nuclear Generating Station.

The table below provides a breakdown of the total cost incurred by the former Ontario Hydro to complete the Darlington Nuclear Generating Station. The total cost amounted to $14.3 billion. The final unit was placed into service on June 14, 1993.

CAPITAL COSTS OF DARLINGTON NUCLEAR GENERATING STATION:

	$ millions
Design and Construction (including Hydro, and contract directs, permanent materials, hydro and contract engineering, construction indirects, overhead)	5,117
Interest charged to the project (interest during construction)	6,202
All costs related to commissioning (commissioning, training, initial fuel load, less the credit for power production during this period)	1,472
Heavy water costs	1,528
Total capital costs of Darlington Nuclear Generating Station	14,319

Ontario Power Generation ("OPG") purchased and assumed certain assets, liabilities, rights and obligations of the electricity generation business of Ontario Hydro on April 1, 1999, including the Darlington Nuclear Generating Station. The assets acquired by OPG on April 1, 1999 were recorded at their fair value, rather than the book value as recorded by Ontario Hydro.

Filed: 2014-03-19
EB-2013-0321
Exhibit L
Tab 4.12
Schedule 6 ED-011
Page 1 of 3

ED Interrogatory #011

Ref: Ex. D2-2-1, Attachment 5, Updated 2014-02-06, page 2; and Ex. D2-2-1, pages 15 – 22.

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

a) Please provide a break-out of management's "high confidence" estimate of the total cost of the DRP, including capitalized interest, escalation and all other costs, in 2013$ and 2014$, according to the following categories: (i) RFR; (ii) Fuel Handling; (iii) Turbine-Generator; (iv) Steam Generators; and (v) Balance of Plant.

b) Please provide a breakout of the: (i) RFR; (ii) Fuel Handling; (iii) Turbine- Generator; (iv) Steam Generators; and (v) Balance of Plan costs according to:
(A) contractor costs; and (B) non-contractor costs.

c) Please state the total cost of the DRP to OPG in 2013$ and 2014$ assuming the RFR, Fuel Handling, Turbine Generator; Steam Generators and Balance of Plan costs exceed budget by: (i) 50%; (ii) 100%; (iii) 150%; (iv) 200%; and (v) 250%. In each scenario, please also state: (i) the percentage of the contractors' cost overruns that are passed on to OPG; and (ii) the DRP's LUEC in 2013$ and 2014$.

Response

a) & b) The table below provides the requested break-out based on the amounts included in Ex. D2-2-1, Attachment 5. Interest and escalation are planned at the Program level and not at the individual project level and therefore have not been provided.

$M		2013$	2014$
RFR	OPG Project Management	[redacted]	[redacted]
	Contractor Cost	[redacted]	[redacted]
	Contingency	[redacted]	[redacted]
Fuel Handling	OPG Project Management	[redacted]	[redacted]
	Contractor Cost	[redacted]	[redacted]
	Contingency	[redacted]	[redacted]
Steam Generators	OPG Project Management	[redacted]	[redacted]
	Contractor Cost	[redacted]	[redacted]
	Contingency	[redacted]	[redacted]
Turbine Generator	OPG Project Management	[redacted]	[redacted]
	Contractor Cost	[redacted]	[redacted]
	Contingency	[redacted]	[redacted]
Balance of Plant	OPG Project Management	[redacted]	[redacted]
	Contractor Cost	[redacted]	[redacted]
	Contingency	[redacted]	[redacted]
		[redacted]	[redacted]

Notes:
1. 2013$ estimate based on Ex. D2-2-1, Attachment 5
2. 2014$ assumed 2% inflation

c) The DRP contracts are structured in a manner that allocates risk to the entity that is best able to manage that risk. For example, the Retube and Feeder Replacement ("R&FR") tooling contract is fixed price, therefore, regardless of cost growth, OPG is protected. The R&FR Execution work is target price with incentives for the contractor to lower costs. In a situation where cost growth is significant, the contractor looses a portion of their fee as well as overheads for additional costs incurred beyond the target price.

The table below provides the "high confidence" DRP cost under a range of contractor cost over-run scenarios including the % of costs passed on to OPG and the impact on the DRP LUEC for each scenario.

	Total DRP cost (P90)		% of Cost Passed to OPG		Impact on LUEC (P90) (Increase)	
	2013$ (Billion)	2014$B (Billion)	2013$	2014$	2013 (cents)	2014 (cents)
50%	10.0	10.2	81%	81%	0.0	0.0
100%	10.2	10.4	75%	75%	0.1	0.1
150%	11.1	11.3	72%	72%	0.3	0.3
200%	12.1	12.3	69%	69%	0.6	0.6
250%	13.1	13.3	68%	68%	0.9	1.0

<u>Assumptions</u>

1. Each project bundle has a variety of contracting strategies including Fixed Price, Target Price, Cost Plus, and Time and Material; the calculation of the “% of Costs Passed onto OPG” is based on these contract strategies. This analysis assumes that the % of cost growth is spread evenly across all elements of the contract including fixed price, materials, and target price.
2. For each scenario, contingency, as reported in part a) and b) is reduced prior to incurring cost growth to the project; i.e. a 50% cost increase to the project decreases contingency and remains within the $10 Billion high confidence estimate.
3. OPG has maintained additional contingency and management reserve, i.e. only contingency distributed to the projects, in part a) and b) has been reduced due to cost overruns. Contingency and management reserve remains for other risks.
4. 2014$ assumed 2% inflation

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]	[redacted]
	Contingency	[redacted]	[redacted]
Fuel Handling	OPG Project Management	83	85
	Contractor Cost	[redacted]	[redacted]
	Contingency	[redacted]	[redacted]
Steam Generators	OPG Project Management	63	64
	Contractor Cost	[redacted]	[redacted]
	Contingency	[redacted]	[redacted]
Turbine Generator	OPG Project Management	195	199
	Contractor Cost	[redacted]	[redacted]
	Contingency	[redacted]	[redacted]
Balance of Plant	OPG Project Management	216	220
	Contractor Cost	[redacted]	[redacted]
	Contingency	[redacted]	[redacted]
Other Costs	Islanding	[redacted]	[redacted]
	System Shutdown	[redacted]	[redacted]
	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]	[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$) or 7.9 ¢/kWh (2014$).

UNDERTAKING JT2.1

Undertaking

To provide additional information with respect to Environmental Defence interrogatory 5, issue 4.7, as set out in Mr. Elson's letter.

Response

OPG provides the following in response to Mr. Elson's letter of April 14, 2014.

a) Management's "high confidence" estimate of the total cost of the DRP, including interest and escalation is $12.9B as stated in Ex D2-2-1 Attachment 5, page 2 of 47. This is the expected expenditure in nominal dollars or dollars of the year. The table below provides a breakdown of the estimate in 2013 and 2014$.

	2013$	2014$
High Confidence Estimate	$10.0B	$10.2B
Escalation	$1.5B	$1.3B
Interest	$1.4B	$1.4B
Total	**$12.9B**	**$12.9B**

b) Confirmed

c) i) No, it is not OPG's position that it can finance DRP for an after tax return of 7%. Please note that in Mr. Elson's letter, discount rate and rate of return are used interchangeably, which is not correct. The 7% referenced is the discount rate OPG applied in its calculation of the DRP LUEC. For rate of return (on equity), see response to ED IR#005. OPG believes 7% is the appropriate discount rate to evaluate the DRP. In EB-2010-008, OPG explained that it assesses differences in risk through cash flows rather than through the discount rate. OPG continues to maintain that risks have been adequately accounted for in the project cash flows.
Mr. Elson's letter references the 2005 CIBC World Markets report and quotes the Bruce Power LP cost of equity to have been assessed by CIBC at between 13.7% and 18% and incorrectly implies that this rate should be compared to OPG's 7% discount rate. Again the cost of equity and discount rates for use in LUEC calculations are different things. Generally speaking rate regulation is lower risk than power purchase contracts. And, in the rate regulated environment in which OPG operates, the ratepayers benefit from this lower risk through a lower cost of financing.

ii) OPG does not have explicit commitment s from the Ontario Electricity Financial Corporation to provide financing for the DRP. OPG expects to finance DRP through corporate debt issued to the Ontario Electricity Financial Corporation which is addressed in Section 3,2 Corporate Long-Term Debt Issues and Section 4.3 Planned Corporate Long Term Debt Issues, Exh. C1-1-2. OPG's sources of equity are its retained earnings and equity investment from its Shareholder.

d) OPG's response to Ex. L-04.7 ED-005 (f) has provided the requested information. The total cost of the DRP is the basis of the estimate of 3.2 cents/kWh shown in the table provided. The LUEC calculation includes interest and escalation (see also responses to L-04 7.1 Staff-031 and L-04 10-17 SEC-055).

ED Interrogatory #005

Ref: Ex. D2-2-1, Attachment 5, Updated 2014-02-06

Issue Number: 4.7
Issue: Are the proposed nuclear capital expenditures and/or financial commitments reasonable?

Interrogatory

According to OPG: "Management continues to communicate, with high confidence, that the cost of DRP will be less than $10 billion in 2013$, excluding capitalized interest and escalation." (Page 2)

a) Please state management's "high confidence" estimate of the total cost of the DRP, including capitalized interest, escalation and all other costs, in 2013$ and 2014$;

b) Please state management's estimate of the probability that the total cost of the DRP will exceed management's "high confidence estimate".

c) Please state the LUEC of the DRP in 2013$ and 2014$ based on management's "high confidence" estimate of its total cost.

d) Please state and justify the reasonableness of the assumed debt-equity ratio, cost of debt, and cost of equity that were used to calculate the LUEC of the DRP.

e) Please state the assumed annual capacity utilization factor that was used to calculate the LUEC of the DRP.

f) Please provide a break-out of the LUEC of the DRP in 2013$ and 2014$ according to the following categories: (i) capital costs; (ii) fuel costs; and (iii) non-fuel operating costs.

Response

a) Management's "high confidence" estimate of the total cost of the DRP, including interest and escalation is $12.9B as stated in Ex D2-2-1, Attachment 5, page 2 of 47. This is the expected expenditure in nominal dollars or dollars of the year.

b) As provided in Ex D2-2-1, Attachment 5, page 38 of 47, Figure C2, OPG's confidence in its high confidence estimate of $10B (2013$) or $12.9B including interest and escalation, is shown to be just under 99% (98.6%). Thus, OPG's estimate of the probability that the total cost of the DRP project will exceed management's high confidence estimate is just over 1%. OPG notes that while the methodology behind Figure C2 can provide a specific probability associated with a specific number, OPG prefers to characterize the $10B (2013$) as simply a high confidence estimate.

c) OPG's estimate of the DRP LUEC, based on OPG's high confidence estimate, is 7.8 cents/kWh (2013$) excluding fixed Corporate Overheads for Pension and Other Post Employment Benefits, or 8.2 cents/kWh (2013$) including fixed Corporate Overheads. In 2014$, the equivalent numbers are 7.9 cents/kWh and 8.3 cents/kWh respectively, using a forecast escalation rate of 1.8% from 2013 to 2014.

d) OPG used a 7% discount rate in the evaluation of the LUEC of the DRP. The basis for this 7% rate has been provided in past OEB proceedings (e.g., response to Energy Probe Interrogatory #2 in EB-2010-0008 (Ex. L-6-002), and is based on the following:

Debt Equity Ratio = 53/47
Debt Rate = 5.94%
ROE = 9.85%
Tax Rate = 25%.

Please see also OPG's response to Pollution Probe Interrogatory #16 (Ex. L-10-016) in EB-2010-0008.

The approach is consistent with the cost of capital reviewed and approved by the OEB in EB-2010-0008 (see Decision with Reasons, March 10, 2011, pp. 111 – 125).

e) The annual capacity factor used to calculate the LUEC of Darlington Refurbishment Project was 88%, with a range of 83% - 93%. Please refer to D2-2-1, Attachment 5, page 42 of 47, Table C7.

f) This table provides the LUECs excluding fixed Corporate Overheads and the fuel and non-fuel operating costs for OPG's high confidence estimate consistent with those underlying the LUEC of 7.5 cents/kWh provided in Ex D2-2-1, Attachment 5, page 2 of 47.

	LUEC in ¢/kWh (2013$)	LUEC in ¢/kWh (2014$)
Refurbishment Costs (High Confidence Estimate)	3.2	3.2
Fuel Costs	0.5	0.5
Non-Fuel Operating Costs	4.1	4.2
Total	7.8	7.9

ED Interrogatory #007

Ref: Ex. D2-2-1, Attachment 5, Updated 2014-02-06

Issue Number: 4.7
Issue: Are the proposed nuclear capital expenditures and/or financial commitments reasonable?

Interrogatory

Please provide the actual capacity (MW), output (GWh) and annual capacity utilization factor of the Darlington Nuclear Station for each year of its operating life.

Response

The following table provides the net maximum continuous rating, net output and unit capability factor of the Darlington Nuclear Generating Station from 2005 - 2013.

DN	2005	2006	2007	2008	2009	2010	2011	2012	2013
Net MCR (MW)	3,512	3,512	3,512	3,512	3,512	3,512	3,512	3,512	3,512
Net Output (TWh)	27.5	26.9	27.2	28.8	26.0	26.5	28.9	28.3	25.1
UCF (%)	90.63	88.71	89.45	94.51	85.93	87.63	95.19	93.21	82.92

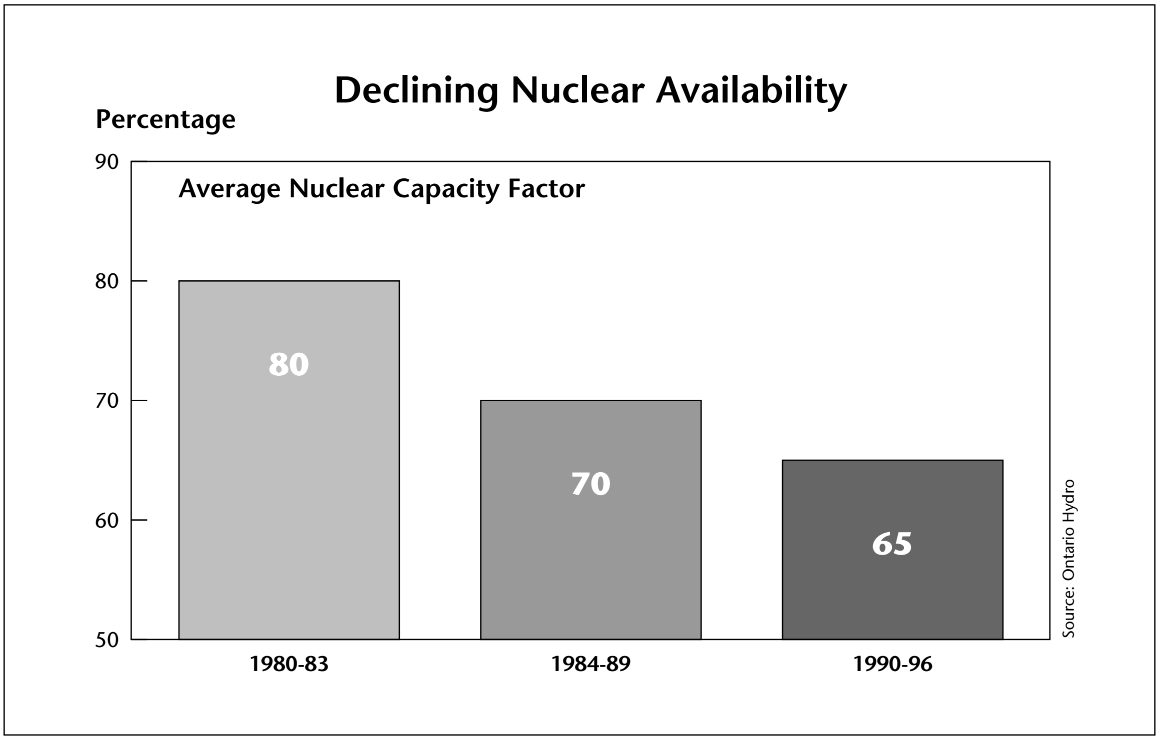
Historical information for 2004 or earlier years has not been provided for the reasons set out in EB-2007-0905, Ex. L-12-6, provided in Attachment 1.

DIRECTION FOR CHANGE

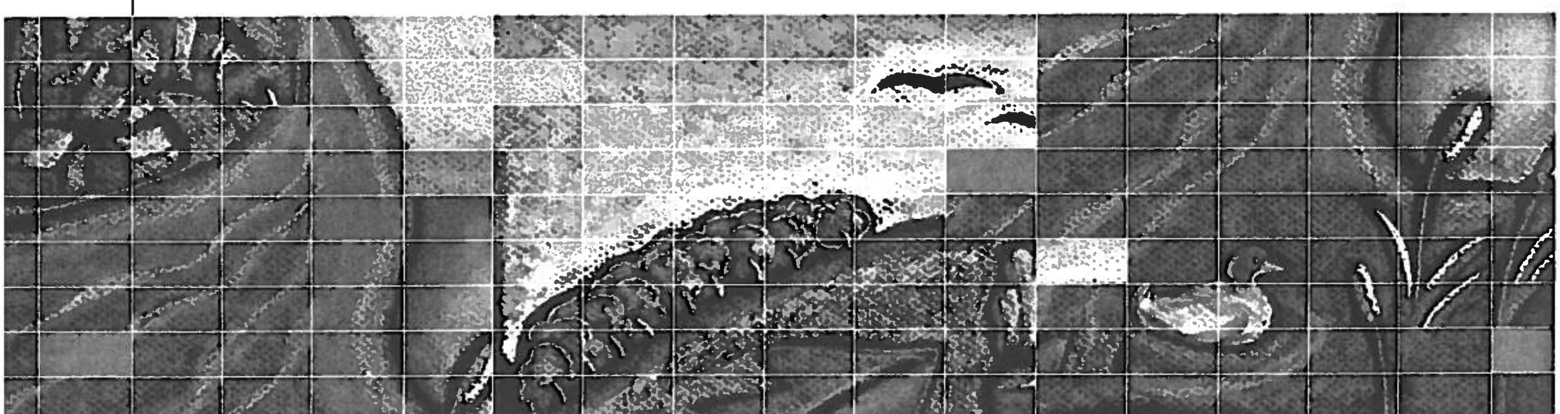
Charting a Course for Competitive Electricity and Jobs in Ontario

Ontario

Ontario Hydro has written-off more than $7 billion in non-performing assets over the last five years. It could be facing additional write-offs related to the Pickering A and Bruce A nuclear stations. Write-offs occur in business because of significant, unexpected changes in market conditions and technology. In Ontario Hydro's case, they also reflect a record of poor decision-making over the last ten years.



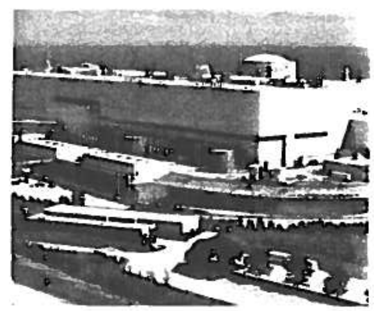
towards sustainable development



ONTARIO POWER GENERATION INC. 1999 PROGRESS REPORT

ONTARIO POWER GENERATION

Nuclear

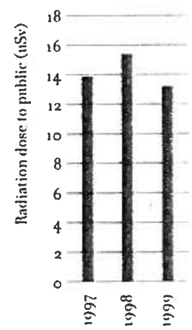


Fossil

General Information	Net Generation	Radiation Dose to Public

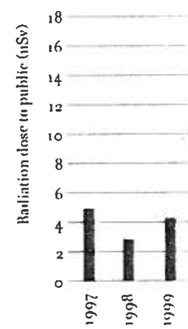
Net generation capacity
Pickering A: 2060 MW
Pickering B: 2064 MW
Located on Lake Ontario in the city of Pickering, each generating station has 4 units. Pickering A is temporarily out of service during the Nuclear Improvement Program. Number of used fuel bundles stored on site: 458,203
Tel: (905) 839-1151

net GWh		
1997	1998	1999
20,442	12,685	13,649



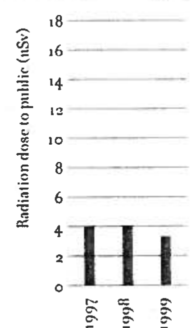
Net generation capacity
Bruce A: 3076 MW
Bruce B: 3140 MW
Located on the eastern shore of Lake Huron, between Kincardine and Port Elgin, each generating station has 4 units. Bruce A is temporarily out of service during the Nuclear Improvement Program. Number of used fuel bundles stored on site: 650,099
Tel: (519) 361-2673

net GWh		
1997	1998	1999
31,405	20,863	22,360



Net generation capacity
3524 MW.
Located on Lake Ontario in the town of Newcastle, 70 km east of Toronto. This generating station has 4 units. Number of used fuel bundles stored on site: 148,857
Tel: (905) 623-6670

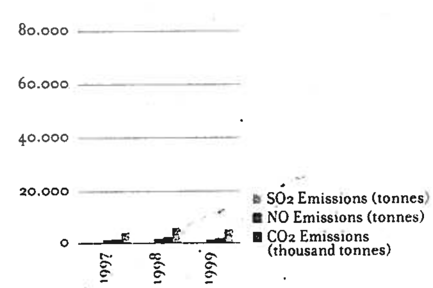
net GWh		
1997	1998	1999
18,426	26,353	25,411



General Information	Net Generation	Generation and Emissions

Net generation capacity:
215 MW
Located west of Thunder Bay, the station has one coal-fired unit equipped with low-NOx burners.
Contact:
Tel: (807) 346-3900 ext. 3903

	1997	1998	1999
net GWh	822	1,434	1,115
Emissions			
SO_2	3,820	6,370	5,560
NO	1,180	2,230	1,310
CO_2	840,000	1,450,000	1,100,000



597. Ali

Board Staff Interrogatory #042

Ref: Exh D2-2-1 Attachment 5, Table C7 (Updated 2014-02-06)

Issue Number: 4.7
Issue: Are the proposed nuclear capital expenditures and/or financial commitments reasonable?

Interrogatory

Table C7 shows that 88% was used as the medium confidence (50%) Average Capacity Factor ("ACF") and 83% was used as the high confidence (90%) ACF.

Based on EB-2010-0008, D2-2-1, Attachment 4, Appendix C, Figure 3, future performance of refurbished units appears as the second largest aspect of the LUEC sensitivity where a base ACF of 87% is quoted. As indicated in section 1.2.4 of the same document, this value was based on the consensus arrived by the discussions with senior station personnel and discussions with the NGD Project Team and the Advisory Committee. Also as described in Section 1.2.4 the high confidence ACF of 82% accounts for the station's since-in-service performance as well as risks associated with the implementation of Integrated Asset Management Plan (AMP), inability to maintain a 3-year outage cycle as well as 20-month outages at year 15 post-refurbishment, if necessary, to replace steam generators.

a) What is the basis for increasing both high and medium confidence ACF values by 1%? What is the impact of such an increase on LUEC?

b) Why did OPG use 87% ACF as the base value when performing the sensitivity analysis for LUEC instead of 82% (given that there is no OPEX for a CANDU comparable to DNGS operating at an ACF equivalent to its first 30-year life ACF of 87% for an additional 30-year life)?

Response

a) Since late 2008, there have been on-going evaluations and assessments of Darlington performance and meetings with senior station personnel to review and update recommendations regarding performance. Many factors that were used as inputs to the earlier assessments have been updated. With respect to ACF, the performance of the station in the past 10 years, ending in 2012, was 89%; the performance of the station in the past 5 years, ending in 2012, was 90.7%. These historical performance factors, combined with other factors such as higher confidence that the Darlington station would be able to maintain a 3-year outage cycle and initiatives to reduce planned outage durations in the post-refurbishment period, led to decision to increase the low, medium and high confidence forecasts by 1% each.

b) The impact on the LUEC of an increase of 1% capability factor in the medium case is a decrease in the LUEC of approximately 0.1 cents per kWh.

Exhibit D2-2-1, Attachment 5, Table C7 (Updated 2014-02-06) indicates a medium confidence capability factor of 88%, which is considered conservative given the station's performance for the last 10 years, which is 89%. The sensitivity analysis provides an assessment against the medium confidence capacity factor and concludes that if the station could only achieve an 83% capacity factor over the extended life, without changing any other assumptions, the LUEC would increase by 0.4 ¢/kWh.

CIBC World Markets

CIBC World Markets Inc.
BCE Place, P.O. Box 500
161 Bay Street, 6th floor
Toronto, ON M5J 2S8

Tel: (416) 594-7000

October 17, 2005

The Ministry of Energy
880 Bay Street, 3rd Floor
Toronto, ON

Attention: James Gillis, Deputy Minister
Rosalyn Lawrence, Director

Dear Sirs and Mesdames:

We understand that, pursuant to a direction provided by the Government of Ontario[1] (the "Province") through the Ministry of Energy (the "MOE"), the Ontario Power Authority (the "OPA") is proposing to enter into a Bruce Power Refurbishment Implementation Agreement (the "RIA") with Bruce Power A L.P. (the "Supplier") and Bruce Power L.P. and a Bruce Power Sharing in Transfers and Refinancings Agreement (the "STAR" and, together with the RIA, the "Agreements") with the Supplier, Ontario Municipal Employees Retirement Board ("OMERS") and TransCanada Corporation ("TransCanada" and, together with OMERS, the "Partners").

The Agreements provide for, among other things, the refurbishment, restart, operation and maintenance of Units 1, 2, 3 and 4 ("Bruce A") of the Bruce Generating Station (and, together with Units 5, 6, 7 and 8 ("Bruce B"), the "Facility") and the supply of electricity produced by the Facility to the Independent Electricity System Operator ("IESO") – Administered Market (the "Proposed Transaction"). In addition, we understand that, in connection with the Proposed Transaction and pursuant to the direction provided by the Province through the MOE and direct negotiations with the Supplier, Ontario Power Generation Inc. ("OPG") is proposing to amend certain terms of its lease agreement dated May 12, 2001 (the "Lease Amendment") with the Supplier relating to the Facility.

We further understand that the Proposed Transaction has been structured to address certain of the Province's material objectives, including:

i) securing the Supplier's commitment to refurbish and restart Units 1 and 2, refurbish Unit 3 and replace the steam generation equipment of Unit 4, in order to provide the Province of Ontario with additional generation capacity through the IESO Administered Market (the "Market");

ii) transferring a reasonable portion of the operating and construction cost risk associated with the refurbishment of the Facility to the Supplier and away from the OPA and, by extension, ratepayers;

[1] In accordance with its powers under Section 25.32 (4) & (7) of the *Electricity Act*.

iii) increasing certainty of capacity plans by establishing key milestone dates for the commencement or re-commencement of commercial operation of Bruce A; and

iv) providing the Supplier an opportunity to earn a financial return that is commensurate with the risks associated with its commitment to refurbish and restart Units 1 and 2, refurbish Unit 3, replace the steam generation equipment of Unit 4 and operate Bruce A.

Engagement of CIBC World Markets

In April 2005, the MOE issued a request for proposals ("RFP") in connection with hiring a financial advisor to assist the MOE in its negotiations of the Proposed Transaction and, if requested, to deliver to the MOE a written opinion in respect of the Proposed Transaction.

By agreement dated as of May 27, 2005 (the "Engagement Agreement"), the MOE retained CIBC World Markets Inc. ("CIBC World Markets" or "we") to act as a financial advisor to the MOE in connection with the Proposed Transaction. In that capacity, we and our financial sub-advisor, Macquarie North America Ltd. ("Macquarie"), among other things (i) reviewed the Financial Model (defined below); (ii) assisted the MOE in completing its financial assessment of the Proposed Transaction; (iii) assisted the MOE in determining an appropriate weighted average cost of capital for the Supplier giving effect to the Proposed Transaction; and (iv) assisted the MOE and its legal advisors in negotiating the principal financial terms of the Agreements. We were not asked to identify or provide any financial advice or analysis regarding any potential alternatives to the Proposed Transaction.

Pursuant to the Engagement Agreement, the MOE has requested that we prepare and deliver this opinion (the "Opinion") as to the fairness to the OPA, from a financial point of view, of the principal financial terms of the Proposed Transaction. The MOE will pay CIBC World Markets a fee, a portion of which relates to the preparation and delivery of this Opinion, and we will share a portion of that fee with Macquarie. In addition, CIBC World Markets will be reimbursed for any reasonable out-of-pocket expenses incurred by CIBC World Markets in connection with the provision of its services. No part of CIBC World Markets' fee is contingent upon the conclusions reached in the Opinion or on the completion of the Proposed Transaction.

Credentials of CIBC World Markets

CIBC World Markets is one of Canada's largest investment banking firms with operations in all facets of corporate and government finance, mergers and acquisitions, equity and fixed income sales and trading and investment research. The Opinion expressed herein is the opinion of CIBC World Markets and the form and content herein have been approved for release by a committee of its managing directors and internal legal counsel, each of whom is experienced in merger, acquisition, divestiture and valuation matters.

Scope of Review

In connection with rendering our Opinion, we have reviewed and relied upon, among other things, the following:

i) a term sheet dated as of July 29, 2005 negotiated between the MOE and the Supplier in connection with the Proposed Transaction;

ii) a draft dated October 17, 2005 of the RIA;

iii) a draft dated October 17, 2005 of the STAR;

iv) a draft dated October 17, 2005 of the Third Amendment to the Amended and Restated Lease Agreement;

v) the Bruce A financial model prepared by the Supplier (the "Financial Model"), reflecting several scenarios of the Supplier's forecast annual financial performance under two alternative business cases being (i) the *status quo* business case that excludes the effect of the Proposed Transaction (the "Status Quo Business Plan"); and (ii) the *pro forma* business case that gives effect to the completion of the Proposed Transaction (the "Pro Forma Business Plan"), for the years ended December 31, 2005 through December 31, 2036 including, among other financial information, a summary income statement, balance sheet and statement of changes in financial position, based upon numerous operating, financial and electricity price assumptions, including sensitivities thereto, agreed to by the Supplier and MOE with assistance from their respective advisors;

vi) a report entitled "Technical Advice on Proposed Bruce A Contract" prepared by Brian Mark Consulting Inc. and R. Strickert & Associates Inc. (the "Technical Advisor"), the MOE's technical advisors in connection with the Proposed Transaction;

vii) presentations made by senior management of the Supplier regarding the scope and material elements of the Supplier's restart and refurbishment plans for the Facility, as reflected in the financial terms of the Proposed Transaction;

viii) a site tour of the Facility;

ix) certain other internal information prepared and provided to us by the MOE and the Supplier's management, primarily financial in nature, concerning the Proposed Transaction and the Facility;

x) certain publicly available financial information concerning the Supplier, the Facility and the nuclear power generation industry;

xi) public information and financial analysis of other electricity and public utility companies, including data relating to public market trading; and

xii) a certificate signed by two senior officers on behalf of the MOE attesting to the accuracy and completeness of the information provided to us.

In addition to the written information described above, CIBC World Markets participated in discussions with the representatives of the MOE, senior management of the Supplier and senior management of the Partners with regard to, among other things, the Agreements, the Proposed Transaction and the operations, financial position, key assets and financial and operating prospects of the Facility. CIBC World Markets has also participated in discussions with Blake, Cassels & Graydon LLP, external legal counsel to the MOE, McCarthy Tétrault LLP, external legal counsel to the Supplier, Macquarie, the Technical Advisor, electricity price forecast consultants engaged by the Supplier and other industry consultants regarding the Agreements, the Proposed Transaction and related matters.

Our Understanding of the Facility

We understand that, pursuant to a lease agreement dated May 12, 2001 (the "Lease Agreement"), Bruce Power L.P., a partnership between TransCanada, OMERS, Cameco Corporation ("Cameco"), the Power Workers' Union and The Society of Energy Professionals (together the "Unions"), is the licensed operator of the Facility, which is located on Lake Huron in Tiverton, Ontario. The Facility houses two nuclear generating stations – Bruce A and Bruce B – and each generating station has four CANDU reactors. At present, six of the eight CANDU nuclear reactors are operational (Units 3, 4, 5, 6, 7 and B8). Bruce A and Bruce B are located over 5km apart and, as a result of the nature of the business and the licensing requirements of the Canadian Nuclear Safety Commission, have extensive staffing requirements which currently stand at approximately 3,800 employees.

We understand that the Bruce A Units were taken out of service between 1995 and 1998 after a decision by Ontario Hydro, which then owned and operated the Facility, to concentrate its resources on improving operations at its other nuclear generating stations. In 2001, Bruce Power L.P. entered into the Lease Agreement with OPG relating to the Facility. Units 3 and 4 were restarted between 2003 and 2004, following an approximate $725 million investment[2], and Units 1 and 2 continue to sit idle. The business plan for the Facility presently anticipates that Units 3 and 4 will come offline in 2009 and 2017, respectively. We understand that the four units of Bruce B are expected to come offline at varying times between 2015 and 2018.

We understand that each of TransCanada, OMERS, and Cameco currently own 31.6% of the Facility, with the Unions owning the remaining 5.2%. We also understand that Cameco will not participate in the Proposed Transaction and, accordingly, that the Supplier will be formed in order for TransCanada and OMERS to pursue the refurbishment, restart and operation and maintenance of Bruce A, thereby increasing their respective interests in Bruce A from 31.6% to 47.4%. We also understand that the existing ownership arrangement for Bruce B will remain in place through the existing separate limited partnership between TransCanada, OMERS, Cameco and the Unions ("Bruce Power L.P.").

Our Understanding of the Agreements

We are not legal, accounting or tax experts. The following description of the Agreements does not purport to be a comprehensive summary of the Agreements and is intended solely to describe our understanding, as the MOE's financial advisors, of the material terms of the Agreements.

We understand that, in accordance with the terms of the Agreements and subject to certain conditions, the Supplier has agreed, at its own expense, to refurbish and restart Units 1 and 2, refurbish Unit 3 and replace the steam generators of Unit 4 (collectively,

[2] The original estimate for this investment was approximately $375 million.

the "Refurbishment") based upon an agreed scope of work and timetable and in accordance with good engineering practices. We also understand that, in connection with the Refurbishment:

i) the Supplier has agreed to refurbish and restart Units 1 and 2, to provide an estimated 1,500 MW of rated generation capacity for approximately 25 years from targeted commencement of operation in 2009;

ii) the Supplier has agreed to refurbish Unit 3, with project commencement targeted for 2007, to provide an estimated 750 MW of rated generation capacity for approximately 25 years from targeted re-commencement of operation in 2012; and

iii) the Supplier has agreed to replace the steam generation equipment of Unit 4, to provide an estimated 750 MW of rated generation capacity for approximately 8 years from targeted re-commencement of operation in 2008.

We also understand that the Technical Advisor has reviewed the scope of work and project management plans and has advised the MOE in its report that the Supplier has identified the material project risks and structured a project management plan to effectively monitor, manage and mitigate these risks. We understand that the Supplier has negotiated numerous contracts relating to the Refurbishment with several qualified engineering and construction firms and that many of these are structured as fixed-price contracts. We understand that the Supplier has estimated that the Refurbishment will cost in excess of $4 billion and that it represents one of the most significant investments in electricity generation undertaken in the Province.

We also understand that the Agreements entitle the Supplier to a specified selling price in respect of actual Bruce A electricity generation[3] for the full term of the Agreements[4] (the "Contract Price"). The initial Contract Price will be $63.00 per MWh (based on a $57.37 per MWh base price and an estimate in respect of a Fuel Pass-Though, as defined below), subject to an annual adjustment in respect of the Ontario consumer price index ("CPI"), an agreed upon sharing of the differences between actual and estimated Refurbishment costs and differences between actual and forecast staffing costs related to certain common Facility functions at the time of decommissioning of Bruce B. Accordingly, we understand that if the Supplier receives a selling price from the sale of electricity to the Market that is in excess of the Contract Price, the Supplier is required to pay such excess to the OPA (the "Revenue Sharing Payment"). Conversely, we understand that, if the Supplier receives a selling price from the sale of electricity to the Market that is below the Contract Price, the OPA is required to reimburse such difference to the Supplier[5] (the "Contingent Support Payment" and together with the Revenue Sharing Payment, the "Contract Payments"). The Contract Payments are determined with reference to defined

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[3] In certain defined circumstances, where the Supplier is unable to supply electricity due to transmission system inadequacy or as a result of an IESO order to curtail generation due to unutilized base-load generation, the Supplier is entitled to receive the Contract Price in respect of deemed electricity generation ("Deemed Generation").

[4] The term of the Agreement is approximately 25 years subject to early termination and extension under certain circumstances.

[5] Subject to a cumulative cap of $575,000,000 prior to such time that Unit 1 and Unit 2 commence commercial operation.

Market price measures or other price measures as required[6] and are paid on a net basis each month for the full term of the Agreements.

We also understand that, pursuant to the Agreements, in addition to the Contract Price, the Supplier is entitled to reimbursement from the OPA of all reasonable costs related to the procurement of nuclear fuel supply used in the generation of Bruce A electricity (the "Fuel Pass-Through"). The Fuel Pass-Through will be paid on a monthly basis by the OPA to the Supplier and is subject to certain OPA review rights to ensure that the Supplier is procuring its nuclear fuel supply in accordance with practices mutually agreed to by the Supplier and the OPA.

We understand that the Agreements do not provide for any annual capacity payments or any other fixed amount in respect of the Supplier's investment in Bruce A and, accordingly, the OPA is only obligated to make Contingent Support Payments, where applicable, in respect of Bruce A's actual electricity generation and, in certain defined circumstances, Deemed Generation.

We also understand that the initial Contract Price is the result of negotiations between the MOE and the Supplier, and is intended to provide the Supplier with an agreed-upon target annual internal rate of return (the "Target IRR"), as measured in the Financial Model, under the mutually agreed-upon set of Base Case operating and financial assumptions. The actual internal rate of return ("IRR") earned by the Supplier will depend upon the actual financial and operating performance of Bruce A and other factors. We have advised the MOE that the actual performance of Bruce A will differ from the Base Case forecast performance and that the differences, either positive or negative, may be material. Accordingly, the actual IRR earned by the Supplier will be either higher or lower than the Target IRR and the difference may be material. Several factors may contribute to such differences, including, among other things, changes in: (i) the Supplier's actual Refurbishment costs; (ii) the actual electricity generation volumes of Bruce A; and (iii) the Supplier's actual operating costs.

We understand that the Contract Price will be subject to certain adjustments, both positive and negative, in respect of changes in the CPI by an amount equal to (i) CPI where CPI is between 0% and 2.5%; (ii) 2.5% plus 60% of the excess of CPI over 2.5% where CPI is in excess of 2.5%; and (iii) 60% of CPI where CPI is less than 0%.

We further understand that the Contract Price will also be adjusted in respect of differences between actual and estimated Refurbishment costs based upon defined sharing bands that are intended to allocate such variance, either favourable or unfavourable, between the Supplier and the OPA. Any variance, other than a variance that is attributable to a *force majeure* event, is allocated 50% to the Supplier and 50% to the OPA, to an agreed upon threshold, and then 75% to the Supplier and 25% to the OPA beyond that threshold ("General Cost Sharing")[7]. Where a Refurbishment cost variance is the result of a *force majeure* event, the sharing arrangements are dependent

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[6] The Agreement provides for Market evolution and circumstances where the Market price is unavailable.
[7] The OPA will share in 50% of the cost overruns up to approximately 111% of the Base Case for Units 1 & 2 and 25% thereafter; the OPA will share 50% of the cost overruns up to approximately 125% of the Base Case for Unit 3 and 25% thereafter.

upon the underlying nature of the *force majeure* event with "Type I" variances being allocated 25% to the Supplier and 75% to the OPA; "Type II" variances being allocated 50% to the Supplier and 50% to the OPA; and "Type III" variances being allocated to the Supplier and the OPA in accordance with the General Cost Sharing arrangements. Actual Refurbishment costs will be subject to certain OPA review and audit rights as described in the Agreements. Any Refurbishment cost variance allocated to the OPA (the "OPA Variance") will result in an adjustment to the Contract Price[8] equal to an amount that amortizes the OPA Variance, based on the Base Case assumptions, including an amount in respect of the Target IRR, over the remaining Base Case forecast volume of electricity generation from the date of adjustment to December 31, 2036. We have advised the MOE that the actual recovery of the OPA Variance may not equal the intended recovery as a result of differences between assumed and actual electricity generation and CPI.

We understand that the Agreements also require the Supplier to pay to the OPA, commencing in 2010, a portion of the annual benefit realized by the Supplier in respect of achieving lower than Base Case forecast operating costs per MWh (the "Operating Efficiency Amount"). The OPA will be entitled to receive 50% of the Operating Efficiency Amount to an agreed upon threshold and then 25% to a second threshold, after which the OPA is no longer entitled to share in the Operating Efficiency Amount. Any amounts paid to the OPA will not be recoverable by the Supplier in a subsequent period where actual operating costs per MWh are higher than the Base Case forecast.

We understand that, under the terms of the Agreements, the OPA will be entitled to receive specified liquidated damages payments in the event that the Supplier is unable to achieve commercial operation of each refurbished Bruce A Unit prior to 3 months following agreed upon milestone dates[9]. Further, if the Supplier is unable to commence commercial operation of Unit 1 and 2 prior to a specified date, the OPA will be entitled to claw-back a portion of any Contingent Support Payments and, if the Supplier is unable to achieve commercial operation of Unit 1 and Unit 2 prior to 33 months[10] from the milestone date, then each party has the right, but not the obligation, to terminate the Agreements.

We also understand that, under the terms of the Agreements, Bruce Power L.P. will be entitled to a minimum selling price in respect of actual Bruce B electricity generation[11] for each year prior to and including 2019 (the "Bruce B Floor Price"). The initial Bruce B Floor Price will be $45.00 per MWh, and is subject to adjustment in respect of CPI in the same manner as the Contract Price. Accordingly, if Bruce Power L.P. receives a selling price from the sale of electricity to the Market that is below the Bruce B Floor Price, the OPA will be required to reimburse such deficiency to Bruce Power L.P. (the "Bruce B Contingent Support Payment"). The Bruce B Contingent Support Payments will be

[8] The Contract Price is increased in respect of any unfavourable variance allocated to the OPA and decreased in respect of any favourable variance allocated to the OPA.

[9] Each Bruce A Unit has a specified milestone date that is 3 months later than the target date for commencement of commercial operation (or, in the case of Unit 3 and 4, re-commencement of commercial operation), subject to extension in respect of certain force majeure events.

[10] The 33 months can be extended to 48 months in respect of Force Majeure events.

[11] In certain defined circumstances where the Supplier is unable to generate electricity due to transmission system inadequacy or as a result of an IESO order to curtail generation due to unutilized base-load generation the Supplier is entitled to receive the Contract Price in respect of deemed electricity generation.

determined with reference to the same Market price measures that are used to determine the Contract Payments in respect of the Bruce A electricity generation. The OPA will be entitled to recapture any Bruce B Contingent Support Payments, to the extent Bruce Power L.P. subsequently realizes selling prices that exceed the Bruce B Floor Price[12].

Under the terms of the STAR, any transfer of an interest in the Supplier prior to 2012, other than between TransCanada, OMERS or any of their wholly owned affiliates, is subject to the OPA's prior consent. Subsequent to 2012, any transfer will require the OPA's consent only if, at the time of the transfer, the Supplier is a defaulting party under the Agreements or the Supplier, the transferee, or its ultimate parent, is not rated at least one notch above investment grade by two or more credit rating agencies. Further, the STAR provides for the Partners or the Supplier to make a payment to the OPA equal to 50% of the financial return in excess of a specified IRR of 20% (the "Windfall Sharing Payment") as a result of any Refinancing or Transfer, as such terms are defined in the STAR, of the Partners' interest in the Supplier[13].

Our General Approach to Analysis

In setting the key financial terms of the Proposed Transaction, we understand that the MOE and the Supplier have negotiated terms that allow the Supplier to earn the Target IRR under the Base Case assumptions. The Financial Model calculates, among other things, an estimated IRR (the "Estimated IRR") using a forecast of the Facility's unlevered free cash flows under either the Status Quo Business Plan or Pro Forma Business Plan, and in each case taking into account a specific set of financial, operating and other assumptions. The Estimated IRR is equal to the Target IRR under the Base Case assumptions, which assumptions have been deemed acceptable by the Supplier and the MOE, after considering the information available to them and receiving advice from their respective legal, financial and technical advisors.

In the case of the Proposed Transaction, the Estimated IRR is calculated using incremental unlevered cash flows ("Incremental Cash Flows"), which are equal to the difference between the Supplier's forecast unlevered cash flows under the Pro Forma Business Plan and the Status Quo Business Plan, for any given set of assumptions. This calculation methodology isolates the forecasted impact of the Proposed Transaction on the Supplier's unlevered free cash flow and, accordingly, allows for the calculation of the an Estimated IRR under various scenarios, in each case, after giving effect to the completion of the Proposed Transaction.

CIBC World Markets compared the Target IRR, as well as a range of forecast Estimated IRRs under alternative scenarios, to its estimate of the Supplier's weighted average cost

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[12] The recapture payment will be the lesser of: (i) the aggregate amount of Bruce B Contingent Support Payments made and not previously recaptured; and (ii) the amount by which the selling price received by Bruce Power L.P. exceeds the Bruce B Floor Price, multiplied by the generation sold at that price.

[13] Refinancing is defined to include any refinancing undertaken by the Supplier and certain refinancings undertaken by Bruce Power L.P. or a Partner in respect of their interest in the Supplier or the Bruce Power L.P. Transfer is defined to include any direct or indirect sale of a Partner's interest in the Supplier and the determination of the Transfer Windfall Sharing Payment includes an ascribed value in respect of the Bruce B Floor Price.

of capital ("WACC"). In addition, CIBC World Markets considered other factors that it determined to be relevant, including the financial return expectations of private market investors in the infrastructure market.

Summary of Our Analysis

Determination of Weighted Average Cost of Capital ("WACC")

CIBC World Markets calculated the WACC for the Supplier based on its after-tax cost of debt and equity and an assumed capital structure using assumptions we considered reasonable.

The assumed capital structure is typically determined based upon a review and analysis of the capital structure of comparable public companies. CIBC World Markets was unable to identify a public company that is directly comparable to the Supplier. However, CIBC World Markets was able to identify several public companies that are similar to the Supplier in certain respects, including British Energy plc ("British Energy"). Accordingly, we reviewed and analyzed the capital structure of several public companies that we considered to be indirectly comparable to the Supplier, including British Energy and six other public electricity generation companies and nineteen public utilities that have some level of nuclear generation capacity. Additionally, CIBC World Markets reviewed and analyzed certain forecast credit statistics for the Supplier under the Base Case assumptions and a range of capital structures to estimate the level of debt financing that might be available to the Supplier in the private bank market and the public bond market. CIBC World Markets was unable to identify any precedent debt financing for a company directly comparable to the Supplier. Further, CIBC World Markets believes that the risk associated with the potential for Refurbishment cost overruns, the potential for the Supplier to fail in achieving commercial operation of one or more of the Units scheduled for Refurbishment, the high operating leverage inherent in the Supplier's business, the risk associated with electricity generation volumes and the negative cash flow profile of the Supplier under the Base Case assumptions during the Refurbishment are all risk factors that prospective lenders would consider in determining their willingness to lend to the Supplier. Notwithstanding these risk factors, it is our view that the Supplier would likely be capable of financing a portion of its capital structure with debt. Accordingly, CIBC World Markets has, based on its analysis, assumed that a reasonable capital structure for the Supplier, on average over the expected life of Bruce A, is comprised of between 20% and 40% debt.

In preparing our financial analysis, we calculated the after-tax cost of debt for the Supplier based on the risk-free rate of return and an estimated borrowing spread to reflect credit risk at the assumed capital structure. Based on our estimate of an appropriate borrowing spread and using an assumed tax rate of 34%, we have estimated the Supplier's cost of debt to be approximately 6.2% and its after-tax cost of debt to be approximately 4.1%.

CIBC World Markets used the Capital Asset Pricing Model ("CAPM") to determine the appropriate cost of equity for the Supplier. The CAPM approach calculates the cost of equity as a function of (i) the risk-free rate of return; (ii) the co-variance of the equity value of the Supplier relative to the variance of the broader public equity market (with such measurement referred to as "Beta"); (iii) an equity risk premium; and (iv) an appropriate premium in respect of the size of the equity value of the Supplier. The Supplier Beta would typically be determined based upon a review and analysis of the Beta of comparable public companies. As noted above, CIBC World Markets was unable to identify a public company that is directly comparable to the Supplier but was able to identify several public companies that are similar to the Supplier in certain respects, including British Energy. Accordingly, we reviewed and analyzed the historic and forecasted Betas[14] of several public companies that were considered by us to be indirectly comparable to the Supplier, including British Energy and six additional public electricity generation companies and nineteen public utilities with some level of nuclear generation capacity.

In determining an appropriate estimate for the Supplier Beta, CIBC World Markets considered several factors that could affect the Beta of the Supplier relative to the observed historic and forecast Betas of the indirect comparables, including, for example, the relative degree of operating leverage inherent in the Supplier's business. Based on its analysis, CIBC World Markets has estimated that the Beta for the Supplier would be within a range of 0.6 to 0.9.

In addition to the Supplier's Beta, CIBC World Markets considered and factored into its estimate of the Supplier's cost of equity a size premium and a premium (the "Supplier Premium") in respect of certain other factors, including certain limitations of CAPM in determining the Supplier cost of equity, such as the transfer restrictions and Windfall Sharing Payments provided for in the STAR, the sharing requirements related to the Operating Efficiency Amount, transfer restrictions prior to 2012 and the relative degree of prospective liquidity for the Partners given the size of the investment and the specialized expertise required to operate Bruce A.

Based on our estimate of the Supplier's Beta, the risk-free rate, and our estimates of the equity risk premium, size premium and Supplier Premium, CIBC World Markets has estimated the Supplier's cost of equity to be in the range of 13.7% to 18.0%.

Our estimate of the Supplier's cost of equity is consistent with our understanding of the Proposed Transaction and our understanding and experience with the private and public capital markets and the power generation and infrastructure industries. Further, we understand that our estimate of the Supplier cost of equity is consistent with Macquarie's principal investing experience in the private and public infrastructure capital markets.

Based on our estimates of a reasonable capital structure, the Supplier's after-tax cost of debt and the Supplier's cost of equity, CIBC World Markets has estimated the Supplier's WACC to be in the range of 10.6% to 13.8% (the "Supplier WACC Range").

Comparison of the Target & Estimated IRR to the Supplier WACC

The Target IRR under the Base Case assumptions falls within the Supplier WACC Range of 10.6% to 13.8%. CIBC World Markets also considered estimates of IRR under several alternative sets of assumptions, including variations from the Base Case in respect of

[14] Historic and predicted Betas based on Barra and Value Line Investment Survey data.

Refurbishment costs[15], and operating efficiency[16]. These sensitivities were based upon information provided by the Supplier, discussions with the Technical Advisor and Macquarie and certain other assumptions made by CIBC World Markets. In all circumstances, including the combination of an upside case in respect of both Refurbishment costs and operating efficiency, the resulting Estimated IRRs fall within the Supplier WACC Range.

Analysis of the Bruce B Floor Price

To analyze the Bruce B Floor Price, we have considered the stream of Bruce B Contingent Support Payments under a series of forecast electricity price curves, each of which has been assigned an estimated probability factor and the resulting probability weighted cash flows have been discounted to arrive at an expected net present value. We subsequently included this expected net present value as a positive Supplier cash flow on the closing of the Proposed Transaction, which resulted in a nominal change to the Estimated IRR that was, in all cases considered, still within the Supplier WACC Range.

Assumptions and Limitations

Our Opinion is subject to the assumptions, explanations and limitations set forth below.

We have not been asked to prepare and have not prepared a valuation or appraisal of Bruce A or any of its assets and our Opinion should not be construed as such. We have not been asked to identify or provide any advice or financial analysis regarding any potential alternative to the Proposed Transaction and our opinion should not be construed as an opinion to the fairness, from a financial point of view or otherwise, of the Proposed Transaction relative to any such potential alternative.

Our financial analyses considered, among other things, whether the principal financial terms of the Proposed Transaction, when taken together and considered as a whole, implied a commercially reasonable financial return on investment for the Supplier.

We are not experts about electricity generation, transmission or markets. With your permission, we have relied upon and have assumed to be correct information provided to us by the MOE regarding the Market's need for the electricity expected to be generated by the Facility upon completion of the Proposed Transaction and the capability of the electricity transmission and distribution network to transmit and distribute all of the electricity to be generated by the Facility after completion of the Proposed Transaction.

With your permission, we have relied upon, and have assumed the completeness, accuracy and fair presentation of all financial and other information, data, advice, opinions and representations obtained by us from public sources, or provided to us by the MOE and its legal counsel, the Supplier and its legal counsel, the Technical Advisor or

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[15] Reflected in the Financial Model as an adjustment to the Refurbishment costs with the associated adjustment made to the Contract Price with the upside case equal to 90% of Base Case Refurbishment costs and the downside case being equal to 130% of Base Case Costs.

[16] Reflected in the Financial Model as an adjustment to the electricity generation forecast, and based on discussions with the Technical Advisor, the upside case is equal to 102.5% of Base Case electricity generation and the downside case is equal to 95% of Base Case electricity generation.

otherwise obtained pursuant to our engagement, and our Opinion is conditional upon such completeness, accuracy and fair presentation. We have not been requested or attempted to verify independently the accuracy, completeness or fairness of presentation of any such information, data, advice, opinions and representations. With respect to operating and financial forecasts provided to us and relied upon in our analysis, we have assumed that they have been reasonably prepared on bases reflecting the most reasonable assumptions, estimates and judgments of the Supplier's management, having regard to the Supplier's plans, financial condition and prospects. We have also assumed that the Proposed Transaction will be completed substantially in accordance with the Agreements.

Without limiting the preceding paragraph, with your permission, we have relied upon the Financial Model in preparing this Opinion. The Financial Model relies, in turn, upon a number of key financial and operating assumptions including, but not limited to, the amount and timing of capital expenditures related to the Refurbishment and maintenance of Bruce A, electricity generation levels, annual cash operating costs, forecast electricity prices in the Market, the amount and timing of Contract Payments, and the amount and timing of capital cost allowance amounts available to the Partners. Further, the Financial Model reflects an assumption that the Supplier is a taxable corporate entity, notwithstanding its legal tax status as a limited partnership, and, accordingly, an estimate in respect of income taxes has been made as a deduction from the forecast cash flows in the Financial Model. We understand that the Technical Advisor has advised the MOE as to the reasonableness of certain assumptions reflected in the Base Case Financial Model and we have not been requested or attempted to assess or verify independently any of the assumptions. If any assumption in the Financial Model proves to be incorrect, the actual financial results of the Supplier, including the Supplier's actual IRR, will differ from the forecast financial results, including the Estimated IRR reflected in the Financial Model, and any material difference would affect the financial fairness of the Proposed Transaction.

The MOE has represented to us, in a certificate signed by two senior officers of the MOE and delivered as at the date hereof, among other things, that the information, opinions and other materials provided to us by or on behalf of the MOE and the Supplier, including the written information and discussions referred to above under the heading "Scope of Review" (collectively, the "Information"), are complete and correct at the date the Information was provided to us and that since the date of the Information, there has been no material change, financial or otherwise, in the financial condition, assets, liabilities (contingent or otherwise), business, operations or prospects of the Facility and no material change has occurred in the Information or any part thereof which would have or which would reasonably be expected to have a material affect on the Opinion.

We have not conducted any investigation concerning the financial condition, assets, liabilities (contingent or otherwise), business, operations or prospects of the Supplier or any of the Partners.

Our Opinion is rendered on the basis of securities markets, economic and general business and financial conditions prevailing as at the date hereof and the conditions and prospects, financial and otherwise, of the Supplier as they are reflected in the Information and as they were represented to us in our discussions with the Supplier's management and legal counsel. In our analyses and in connection with the preparation of our Opinion, we made numerous assumptions with respect to industry performance, general business, market and economic conditions and other matters, many of which are beyond the control of any party involved in the Proposed Transaction.

In providing this Opinion, we are not opining on any specific term of the Agreements, the Lease Amendment or a particular element of the Proposed Transaction but are providing our opinion on the principal financial terms of the Proposed Transaction, when taken together and considered as a whole, based upon the information available to us at the date hereof.

The Opinion has been provided to the MOE for its use only in connection with considering the financial merits of the Proposed Transaction and may not be relied upon by any other person or for any other purpose without the prior written consent of CIBC World Markets.

The Opinion is given as of the date hereof and, although we reserve the right to change or withdraw the Opinion if we learn that any of the information that we relied upon in preparing the Opinion was inaccurate, incomplete or misleading in any material respect, we disclaim any obligation to change or withdraw the Opinion, to advise any person of any change that may come to our attention or to update the Opinion after today.

Opinion

Based upon and subject to the foregoing and such other matters as we considered relevant, it is our opinion, as of the date hereof, that the principal financial terms of the Proposed Transaction, when taken together and considered as a whole, are fair, from a financial point of view, to the OPA.

Yours truly,

CIBC World Markets Inc.


Achieving Balance
Ontario's Long-Term Energy Plan
Ontario

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

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

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

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

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

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

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

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

The nuclear refurbishment process will adhere to the following principles:

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

Ontario poised to enter new nuclear era: [ONT Edition 1]

Urquhart, Ian. **Toronto Star** [Toronto, Ont] 01 May 2006: A17.

Abstract (summary) Translate [unavailable for this document]

Full Text Translate [unavailable for this document]

Ontario is about to embark on a new nuclear era.

This week, Energy Minister Donna Cansfield is expected to go to caucus (Tuesday) with her 20-year plan and to cabinet soon afterward, with a public announcement expected later this month.

However, it is the worst-kept secret at Queen's Park that the plan includes new nuclear power plants to replace the existing reactors, which supply about half of Ontario's electricity and are coming to the end of their design life.

For the past eight months, Premier Dalton McGuinty has been dropping broad hints about the government's pro-nuclear stance.

But sources say the Cansfield plan will contain some surprises, including a heavier-than-expected emphasis on conservation and some caveats about the nuclear option.

Last December, the Ontario Power Authority - a government- appointed advisory body and procurement agency - gave short shrift to conservation and placed heavy emphasis on nuclear power in its recommendations.

The power authority allocated just 5 per cent of its proposed "supply mix" to conservation.

But it called for nuclear power to continue to supply about 50 per cent of our electricity needs, with a dozen reactors replacing old ones at a cost of up to $35 billion.

Cansfield, who handled the conservation file for the government prior to becoming energy minister last fall, will adjust these percentages, according to sources in the government.

She won't go as far as the anti-nuclear environmentalists want; they say the government can meet the province's electricity needs over the next two decades with no new nuclear power but with an aggressive conservation plan that would cost half as much as replacement reactors. Cansfield believes that is unrealistic.

But she will go further than the power authority recommended on the conservation side, particularly in the area of "load management" - paying industry to scale back operations during peak usage periods when the alternative is to import costly power from the United States.

As for nuclear power, Cansfield is expected to raise cautionary flags about the capacity of the nuclear industry to meet demand for new reactors within the power authority's time frame.

Sources say Cansfield will also stipulate that any new reactors must be built for a fixed price , with none of the cost overruns that plagued past projects.

Darlington , the last nuclear plant built in Ontario, was originally estimated at $5 billion but came in at $14.3 billion when it was finally completed in 1993.

Unanswered in Cansfield's plan are the key questions of who should operate the new reactors (government-owned Ontario Power Generation or a private sector firm), where they should be located (likely alongside existing nuclear plants), and what technology should be used (CANDU, the Canadian reactor, or a foreign design).

The government wants to keep these questions open to maximize its leverage in future negotiations with contractors, including Atomic Energy of Canada Ltd. (AECL), the federal agency that builds CANDU reactors.

Before getting to that stage, however, the government must first clear the hurdle of an environmental assessment, which will be the first ever conducted on a nuclear plant in Canada. Darlington was launched before environmental assessments were required.

The whole process, from the decision to build through environmental assessment and other regulatory hurdles to construction of the plant, could take up to 10 years.

The critics of nuclear power are not waiting to attack, however.

Indeed, NDP Leader Howard Hampton started on the attack last week with a series of questions linking the government's nuclear plans to the 20th anniversary of the Chernobyl disaster.

Finance Minister Dwight Duncan accused Hampton of "fear- mongering."

On the other side of the debate are the provincial Conservatives, who have no problem with the nuclear option but say the government is foolish to be phasing out its coal-fired power plants. Major industrial users and the power workers' union are also making the case for coal.

Conservative energy critic John Yakabuski said in the Legislature last week that the government should be investing in "clean coal," to which Cansfield responded that there is no such thing, at least not with current technology.

The Liberals could get whipsawed in this debate, losing votes on the left to the anti-nuclear New Democrats and on the right to the pro-coal Conservatives.

To counter these attacks, the Liberals plan to portray McGuinty as the first premier in two decades who is willing to make the tough but necessary decisions about electricity.

That may be spin, but it's hard to argue with.

Ian Urquhart's provincial affairs column appears Monday, Wednesday and Saturday.

iurquha @ thestar.ca.

Indexing (details)   Cite

Title	Ontario poised to enter new nuclear era: [ONT Edition 1]
Author	Urquhart, Ian
Publication title	Toronto Star
Pages	A17
Number of pages	0
Publication year	2006
Publication date	May 1, 2006
Year	2006
Section	Opinion
Publisher	Torstar Syndication Services, a Division of Toronto Star Newspapers Limited
Place of publication	Toronto, Ont.
Country of publication	Canada
Publication subject	General Interest Periodicals--Canada
ISSN	03190781
Source type	Newspapers
Language of publication	English
Document type	NEWSPAPER
ProQuest document ID	438996987
Document URL	http://search.proquest.com.ezproxy.torontopubliclibrary.ca/docview/438996987?accountid=14369
Copyright	(Copyright (c) 2006 Toronto Star, All Rights Reserved.)
Last updated	2010-06-30
Database	3 databases View list

THE CANADIAN PRESS

Ont. says all bidders remain in the running for nuclear plants despite costs

The Canadian Press [Toronto] 27 Nov 2008.

Abstract (summary)

Full Text

TORONTO _ All three bidders are still in the running to build new nuclear reactors in the province, company and government officials said Thursday, as critics charged that speculation about a withdrawal highlights tensions over who will be on the hook for cost overruns.

Energy and Infrastructure Minister George Smitherman denied a report that U.S. nuclear giant Westinghouse Electric Co. has pulled out of the race because it just wanted to supply technology and not be responsible for cost overruns and delays.

The government wants a company to design and build reactors on a fixed-price basis so ratepayers aren't saddled with billions of dollars in debt if the project goes over budget.

When questioned in the legislature Thursday, Smitherman called the reports ``erroneous'' and said Westinghouse submitted paperwork to Infrastructure Ontario ``as recently as a few days ago.''

The minister made the comments despite telling a newspaper a day earlier that Westinghouse would prefer to play a more modest role in the process.

``We want to have a process that has risk transfer,'' Smitherman said Thursday. ``That's a difficult point of negotiation _ no one would pretend otherwise around that. But it's an essential and important principle for the ratepayers of the province of Ontario.

``We're going to do our best to manage the process in that context, and we feel confident that we're headed towards a good result.''

Westinghouse spokesman Vaughn Gilbert also confirmed the company ``continues to pursue this opportunity.''

Greenpeace energy analyst Shawn Patrick Stensil said Westinghouse's apparent hesitation highlights the risks associated with the government's nuclear plan.

``The nuclear vendors know more than anyone the risks of proceeding with a plant _ they know that taking that risk on themselves could mean bankruptcy,'' Stensil said.

``If you can't get the nuclear industry to assume the risk of their own reactors, why should the public trust them?''

Stensil said the most recent indication the industry didn't want to take on the extra risk came earlier this month, when Smitherman announced the province was again delaying the deadline for the final bid proposals for two new reactors to be built at the site of the existing Darlington nuclear station.

The deadline for final bids was originally set for October, then Dec. 31, and it has now been pushed to sometime in early 2009. Crown-owned Atomic Energy of Canada Ltd. and France's Areva Group are also in the running to provide the complete package.

Stensil also noted that Areva and AECL have both started pre-licensing of their reactor designs, but not Westinghouse.

While neither side confirmed doubts, gossip and speculation is all industry watchers have to go on because there's a blackout on any public debate on the reactor bids, he said.

``It's easy for the government to claim that everything is normal,'' Stensil said.

NDP Leader Howard Hampton challenged Smitherman in the legislature, saying while Westinghouse may be willing to supply some equipment, ``they're not interested in the bidding process that the McGuinty government has outlined.''

``The government doesn't want to admit that these big nuclear projects are subject to huge billion-dollar cost overruns, but in the back room, that's exactly what they're negotiating with,'' Hampton said afterward.

``The private companies always want the government standing in the background holding the bag, accepting all the risk.''

Indexing (details)

Cite

Subject	Nuclear power plants; Nuclear reactors; Risk
Company / organization	Name: Westinghouse Electric Co NAICS: 333415, 333611, 334511, 335313, 515120, 551112
Title	Ont. says all bidders remain in the running for nuclear plants despite costs
Publication title	The Canadian Press
Publication year	2008
Publication date	Nov 27, 2008
Year	2008
Publisher	Canadian Press Enterprises Inc.
Place of publication	Toronto
Country of publication	Canada
Publication subject	General Interest Periodicals--Canada
Source type	Wire Feeds
Language of publication	English
Document type	News
ProQuest document ID	359985326
Document URL	http://search.proquest.com.ezproxy.torontopubliclibrary.ca/docview/359985326?accountid=14369
Copyright	Copyright The Canadian Press Nov 27, 2008
Last updated	2013-05-08
Database	CBCA Complete

AECL favoured to build Ontario reactors: sources

Howlett, Karen; McCarthy, Shawn. **The Globe and Mail** [Toronto, Ont] 15 May 2009: A.7.

Abstract (summary)

Full Text

Risk-sharing deal with Ottawa sought

The Ontario government has selected Atomic Energy of Canada Ltd. as the leading bidder to build the province's first new reactors in a generation, but wants assurances Ottawa will share the risks on the multibillion-dollar project, sources say.

Premier Dalton McGuinty has instructed the head of the province's infrastructure agency to begin bilateral negotiations with the Harper government, said sources familiar with the talks.

"If the feds step up to the plate, then I think there's likely to be a deal with AECL," one source said.

Ontario wants to give Canada's flagship nuclear company the nod, another source said.

"AECL has basically been chosen," he said. "The province wants to negotiate with AECL and the feds on an exclusive basis. But they have not notified the federal government of that yet."

A key issue is how much risk the federal government would assume for any cost overruns. The province wants a company to design and build reactors on a so-called turnkey, fixed-price basis in the hopes of avoiding the mistakes associated with previous projects, which saddled Ontarians with $12-billion in debts.

Officials in the Premier's office declined to comment.

Diane Flanagan, a spokeswoman at Infrastructure Ontario, said a winning bidder has not been chosen. "The process is still under way," she said.

Crown-owned AECL is competing against two global players to build Ontario's first new reactors since the 1980s at the Darlington nuclear station in Clarington, east of Toronto. AECL's main rival is France's Areva Group. A third company, Westinghouse Electric Co., wants to just supply technology rather than a turnkey operation, sources have said. Federal officials and Areva Canada president Armand Laferrere declined to comment on the state of the bid. Areva has said that AECL has not completed the design work on its Advanced Candu reactor, which it said increases the risk of cost over-runs.

The new reactors are part of the Ontario government's plan to spend $26-billion expanding and refurbishing its fleet of reactors to help meet the province's electricity needs over the next two decades. But such projects can be politically risky because costs for raw materials and labour are rising.

George Smitherman, the province's Deputy Premier in charge of infrastructure, "had sticker shock at all the bids," a source said.

Sources say Ontario wants Ottawa to provide financial support and backing for AECL's price guarantees. At the same time, Queen's Park has long worried about Ottawa's commitment to AECL - the federal government is mulling either selling a majority or minority interest in the company. But AECL's future is intrinsically linked to Ontario, because its value will depend on whether it can sell reactors in its home province.

The Ontario decision comes as the federal government is set to solicit interest among Canadian and international companies in forming a strategic partnership with AECL, including taking equity stakes.

Ottawa has been quietly reviewing AECL ownership for more than two years, and has been sitting on a report from the National Bank of Canada that says the corporation would benefit from a larger international partner as it attempts to sell its new ACR technology around the world.

Sources say the federal government has called in a team of international bankers to provide a valuation for AECL and its assets.

Indexing (details)

Cite

Title	AECL favoured to build Ontario reactors: sources
Author	Howlett, Karen; McCarthy, Shawn

Publication title	The Globe and Mail
Pages	A.7
Publication year	2009
Publication date	May 15, 2009
Year	2009
Dateline	TORONTO and OTTAWA
Section	National News
Publisher	The Globe & Mail division of Bell Globemedia Publishing Inc.
Place of publication	Toronto, Ont.
Country of publication	Canada
Publication subject	General Interest Periodicals--Canada
ISSN	03190714
Source type	Newspapers
Language of publication	English
Document type	News
ProQuest document ID	382630692
Document URL	http://search.proquest.com.ezproxy.torontopubliclibrary.ca/docview/382630692?accountid=14369
Copyright	2009 CTVglobemedia Publishing Inc. All Rights Reserved.
Last updated	2010-06-24
Database	Canadian Newsstand Major Dailies

Nuclear bid rejected for 26 billion; Ontario ditched plan for new reactors over high price tag that would wipe out 20-year budget

Hamilton, Tyler. **Toronto Star** [Toronto, Ont] 14 July 2009: A.1.

Abstract (summary)

Full Text

The Ontario government put its nuclear power plans on holdlast month because the bid from Atomic Energy of Canada Ltd., the only "compliant" one received, was more than three times higher than what the province expected to pay, the Star has learned.

Sources close to the bidding, one involved directly in one of the bids, said that adding two next-generation Candu reactors at Darlington generating station would have cost around $26 billion.

It means a single project would have wiped out the province's nuclear-power expansion budget for the next 20 years, leaving no money for at least two more multibillion-dollar refurbishment projects.

"It's shockingly high," said Wesley Stevens, an energy analyst at Navigant Consulting in Toronto.

Energy and Infrastructure Minister George Smitherman announced on June 29 he was suspending a competitive process for the purchase of new reactors for Ontario. He cited the price tag as "billions" too high, but would not reveal the amount of the bid from AECL, deemed the only compliant proposal out of three offers.

AECL's $26 billion bid was based on the construction of two 1,200-megawatt Advanced Candu Reactors, working out to $10,800 per kilowatt of power capacity.

By comparison, in 2007 the Ontario Power Authority had assumed for planning purposes a price of $2,900 per kilowatt, which works out to about $7 billion for the Darlington expansion. During Ontario Energy Board hearings last summer, the power authority indicated that anything higher than $3,600 per kilowatt would be uneconomical compared to alternatives, primarily natural gas.

Much of the dramatic price increase relates to the cost of labour and materials, which have skyrocketed over the past few years. Nuclear suppliers and their investors also have less tolerance for risk.

The bid from France's Areva NP also blew past expectations, sources said. Areva's bid came in at $23.6 billion, with two 1,600-megawatt reactors costing $7.8 billion and the rest of the plant costing $15.8 billion. It works out to $7,375 per kilowatt, and was based on a similar cost estimate Areva had submitted for a plant proposed in Maryland.

"These would be all-in costs, including building a new overpass and highway expansion to get the equipment in," said a source from one of the bidding teams, who asked to remain anonymous, citing confidentiality agreements signed with the province.

Stevens said Areva's lower price makes sense because the French company wasn't prepared to take on as much risk as the government had hoped. This made Areva's bid non-compliant in the end. Crown-owned AECL, however, complied with Ontario's risk-sharing requirement but was instructed by the federal government to price this risk into its bid. "Which is why it came out so high," said Stevens.

It's why Smitherman has thrown the ball in the federal government's court in hopes of having Ottawa pay a portion of the cost. The Harper government has given no indication whether it's prepared to commit billions of dollars to subsidize Ontario electricity consumers.

Amy Tang, a spokeswoman for the energy ministry, wouldn't confirm or deny either bid amount. She said the bidding process was complex and no single number tells the full story.

"By simplifying any one submission down to a single number at this point would be very difficult to do and highly speculative," Tang said.

But the figures shed light on a process that has so far attempted to shield the true cost of building nuclear power capacity in Canada, said Shawn-Patrick Stensil, nuclear researcher at Greenpeace Canada.

"Paying $26 billion for prototype reactors that may not even work is a huge gamble for the province," said Stensil, adding the money could be better spent on less risky and greener alternatives. "This whole renaissance in nuclear was built on the premise of cheap reactors, and that's what they haven't been able to deliver."

Credit: Toronto Star

Illustration
Caption: Energy Minister George Smitherman suspended process.

Indexing (details)

Cite

Company / organization	Name:	Atomic Energy of Canada Ltd
	NAICS:	325188, 334519, 221122
	DUNS:	20-615-7968

Title	Nuclear bid rejected for 26 billion; Ontario ditched plan for new reactors over high price tag that would wipe out 20-year budget
Author	Hamilton, Tyler
Publication title	Toronto Star
First page	A.1
Publication year	2009
Publication date	Jul 14, 2009
Year	2009
Section	News
Publisher	Torstar Syndication Services, a Division of Toronto Star Newspapers Limited
Place of publication	Toronto, Ont.
Country of publication	Canada
Publication subject	General Interest Periodicals--Canada
ISSN	03190781
Source type	Newspapers
Language of publication	English
Document type	News
ProQuest document ID	439602306
Document URL	http://search.proquest.com.ezproxy.torontopubliclibrary.ca/docview/439602306?accountid=14369
Copyright	Copyright (c) 2009 Toronto Star. All Rights Reserved.
Last updated	2010-06-30
Database	3 databases View list

Filed: June 18, 2008
EB-2007-0707
Exhibit I
Tab 31
Schedule 90
Page 1 of 1

POLLUTION PROBE INTERROGATORY 90

QUESTION

Issue: Nuclear for Base-Load, A11 and A12

Please provide your best estimates of the LUECs for a representative sample of natural gas-fired combined heat and power plants assuming:

a) a real social discount rate of 8%;

b) overall energy efficiencies for the CHP plants of: i) 80%; and ii) 90%;

c) annual capacity utilization rates of i) 50% and ii) 90%; and

d) the OPA's natural gas commodity cost forecast.

RESPONSE

The requested LUECs and breakouts are shown in Table 1 below.

Table 1: LUECs of Representative CHP plant

CHP (8% Discount Rate)

ACF	50%	90%
Capital costs ($/MWh)	37	21
FOMA ($/MWh)	5	3

Efficiency (%)	Gas price $/MMBTU	Fuel Cost ($/MWh)	VOMA ($/MWh)	LUEC ($/MWh)	
80	8	34	3	79	60
	11	47	3	92	73
	15	64	3	109	90
90	8	30	3	75	57
	11	42	3	87	68
	15	57	3	102	83

Source: OPA

The calculations are based on the costs of industrial CHP as provided by Navigant Consulting Inc. in Exhibit D-3-1, Attachment 2.

OPG Review Committee

March 15, 2004

The Honourable Dwight Duncan, MPP
Minister of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario

Dear Minister:

In accordance with your direction of December 16, 2003, we have the honour of presenting to you our report on the future role of Ontario Power Generation Inc. (OPG) in the electricity sector; the future structure of OPG; the appropriate corporate governance and senior management structure; and the potential refurbishing of Pickering A Units 1, 2, and 3.

We would like to thank the many people who helped us to better understand the complex issues surrounding the current circumstances of OPG, the Pickering Return to Service Project and the Ontario electricity sector in general.

We would particularly like to thank the staff members from across the Ontario Public Service who provided support in the areas of logistics, research and public policy advice.

Respectfully submitted,

Original signed by

The Honourable John Manley, P.C., M.P., B.A., LLB, Chair

The Honourable Jake Epp, P.C., B.A., B.Ed., LL.D.

Peter C. Godsoe, O.C.

V. Pickering

Assessing and making recommendations on Pickering A Units 1, 2 and 3 was the most technically complex and urgent matter to confront us.

Unit 4 was one of four units at Pickering A that were taken out of service in 1997 because of regulatory concerns, and so that resources could be focused on upgrades at other nuclear facilities. Unit 4 was the first of the Pickering A units to return to service. We were asked to advise on the potential refurbishment of the remaining three.

The facts around the refurbishment of Pickering A Unit 4 are well known:

- The final cost of the project, at $1.25 billion, was roughly three times the estimate put forward in 1999.
- The scheduled date for completion slipped by more than two years, from mid-2001 to late September 2003.

In its report last fall, the Pickering A Review Panel, which is referred to as the Review Panel in this report, stated that "management of the project from initial planning to execution was seriously flawed. The Review Panel found that well-established industry practices and steps for carrying out a project of this size and complexity were not followed." It also recognized that the "ultimate responsibility must lie with the OPG Board and senior management and how they exercised their oversight responsibilities." After the release of the report, OPG's Chair, Chief Executive Officer and Chief Operating Officer resigned. The board and CEO have been replaced on an interim basis.

During the time we carried out our work, the interim board of directors of OPG decided to stop all planning and preparation activity on Units 2 and 3 so that they could concentrate their resources on Unit 1. We agree with this decision. In our view, further development work on Units 2 and 3 should not go ahead until it is clear that OPG will be able to succeed at the Unit 1 project.

Our focus in this chapter is therefore on whether Pickering A Unit 1 should proceed. Our assessment of this question is necessarily based on the information available to us at this time. Large construction projects by nature carry risk. Because of the sheer amount of money involved, approvals must be contingent on continued oversight and continued management of project risk. This applies to all well-run projects, whether in the private or public sector. Controls and checkpoints are essential both before and after construction starts.

In our view the two key questions we had to address are:

- Does the project make economic sense?
- Can the project be done on time and to budget?

The economic analysis showed us that proceeding with the $500 million investment necessary to complete Unit 1 would result in an electricity cost that is between $20 and $30 less per megawatt hour than the cost of electricity from a combined cycle gas plant, the next best alternative for baseload generation.

The revenues from the electricity generated by the project would be sufficient to repay the $500 million investment required, demonstrating a robust business case in favour of proceeding, with a net present value of between $95 million and $235 million.

Achieving this outcome requires completing the project on time and to budget. We reviewed the project intensively with the OPG Unit 1 Project Team and with an independent project oversight team (the Schiff team described below). We asked a series of key questions to assess the readiness of the project.

Ultimately we arrived at the conclusion that the OPG interim board, OPG management, and the Unit 1 Project Team have developed a plan to reduce or eliminate the major sources of the delays and cost overruns that occurred on Unit 4. We believe that the risk on this project has been managed down to a reasonable level but that stringent oversight must continue to ensure project risk remains at an acceptable level.

Based on the above, we are recommending that the Unit 1 project proceed.

Following this overview is a section detailing the economic analysis of the Unit 1 Project followed by a section on the project management status. Our formal recommendations can be found at the end of the chapter.

The economics of the project

For the economic analyses, we drew on the advice of CIBC World Markets Inc. and PJBTO Associates Ltd. With their help, we reviewed the economics of the Pickering A Unit 1 project, examining the project from two perspectives. In the Alternative Supply

Analysis, we compared it to an alternative option for baseload supply. We also carried out a business case analysis.

The estimated remaining cost to complete the Unit 1 project is a range of $450 million to $600 million, with the base case estimate being $500 million. The question we asked is whether investing this $500 million made economic sense.

Key Findings

Alternative Supply Analysis

- This analysis used a measure called the Levelized Unit Energy Cost (LUEC) that is often used to compare costs consistently across generation options that have different operating lives and cost characteristics.

- On a go-forward cost basis, the electricity cost for the Unit 1 project using LUEC analysis is projected to be between $20 to $30 cheaper per MWh (or 2 to 3 cents cheaper per KWh) than that of a combined cycle gas plant running as base load.

Business Case Analysis

- This analysis used a Net Present Value (NPV) approach, which estimates the net value in today's dollars of all the outflows and inflows of a project over a specific number of years into the future. It uses a "discount rate" for future flows that reflects perceived risk.

- The NPV for the project based on go-forward costs and using an electricity price projection based on the current market structure ranges from $95 million to $235 million, depending on the discount rate used. An NPV of zero or greater indicates the project is financially feasible.

Below, we first explain the assumptions underlying the analyses and then present the results in more detail.

Key Parameters

To understand the economics of the project, key pieces of information are needed. These include the investment that must be made in the project, as well as such elements as the project's operating life and annual costs. The table below sets out the key parameters. The terms are explained below.