ONTARIO POWER GENERATION	Document Number: FIN-TMP-PA-004*	Revision: R005	Page: i of ii
	BUSINESS CASE – PICKERING 5-8 CONTINUED OPERATIONS		

OFFICE OF THE PRESIDENT & CEO — OPG CONFIDENTIAL

JUL 12 2012

April 26, 2012

2012 Business Case Update - Pickering Continued Operations

Reviews and Approvals

Name	Location	Title	Action	Signature	Date
P. Spekkens	P82-6	Vice President, Science & Technology	Technical Review	Paul Spekkens	May 7, 2012
M. Elliot	P82-6	Chief Nuclear Engineer	Technical Concurrence		May 10, 2012
P. Pasquet	P82-4	Senior Vice President - Nuclear Programs and Training	Concurrence		May 15, 2012
G. Jager	P42-E3	Site Vice President, Pickering	Submit BCS	Please sign on Recommendation Page	31 MAY 2012
W. Robbins	P82-6A1	Chief Nuclear Officer	Recommend BCS	Please sign on Recommendation Page	2012-06-08
D. Power	H7 E1	Vice President, Corporate Business & Investment Planning	Finance Review		2012
D. Hanbidge	H19-F27	Chief Financial Officer	Finance Approval	Please sign on Recommendation Page	July 10/12
T. Mitchell	H19-A24	President & CEO	Approval	Please sign on Recommendation Page	July 22 2012

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PICKERING CONTINUED OPERATIONS – 2012 BCS UPDATE

1. RECOMMENDATION:

1. Continue to assume Continued Operations as the basis for Business Planning in order to extend the life of the Pickering 5-8 units, and coincidentally the Pickering 1 and 4 units, to approximately 2019 to 2020.
2. Continue the major component work i.e. pressure tube inspections, Spacer Location and Relocation work, boiler maintenance and inspections to allow operation up to 247,000 EFPH on the pressure tubes.

OPG's updated assessment shows that there is substantial value, estimated at $520 M NPV (2012$) to the Ontario electricity system of being able to operate the Pickering 5-8 Units beyond their originally assumed operating lives of 2014/2016 until 2019 to 2020. This includes the value of being able to continue to operate Pickering Units 1 and 4 until 2020 as the shutdown of Units 1 and 4 would have been required in 2016, co-incident with the shutdown of the last two units at Pickering 5-8. The additional energy supplied to the province of Ontario is approximately 109 TWh. The value to the Ontario electricity system is based on the difference between the cost of Pickering's output and OPG's estimate of the likely cost of replacing that output with other sources of generation in the period 2014 - 2020. Operation of the Pickering units in the 2014 to 2020 period also provides flexibility to the electricity system to address potential capacity shortfalls as other nuclear units undergo refurbishment.

The $520M NPV (2012$ PV) is lower than the previous assessment (completed in 2009) of $1.1 Billion (2009$ PV). Several reasons contribute to the change in assessed value; however the primary reason is that that the forecast value of Pickering's energy to the Ontario system is now lower as a result of a lower electricity demand forecast and lower gas price forecasts (decreases value). In addition, OPG has modified its assessment methodology to take account of the impact of projected levels of surplus baseload generation on the value to the system of the output of the Pickering plant. These three factors contributed to a decline in the assessed value. These three factors were partially offset by the fact that OPG is now projecting that the Pickering 5-8 units will operate to 247,000 equivalent full power hours (compared to 240,000 equivalent full power hours in the previous assessment), which is equivalent to approximately three-quarters of a year of additional operating life on each unit. Continued Operations remains an economically viable investment.

The assessment includes the costs of the incremental work required to implement Continued Operations at Pickering 5-8 (e.g. pressure tube inspections, spacer location and re-location, boiler maintenance and inspections, reactor components inspections, work resulting from component condition assessments) as well as a share of the costs of the Fuel Channel Life Management Project. These costs are now estimated at $88 million over the period 2013-2014. Total costs of the project including Pickering's portion of the Fuel Channel Life Management Project are forecast to be $200.7M.

The assessment also includes the incremental impact of 104 planned outage days during the period 2013-2014 to execute work to enable Continued Operations. The incremental costs and generation impacts in the period 2012-2014 of Pickering Continued Operations are summarized in the table below.

Costs & Generation Impacts (2012- 2014)	LTD 2009-11	2012 Proj	2013	2014	2015 - 2020	2013-2014 Tot	Overall Total
OM&A ($M)	55.1	42.8	37.2	47.9	N/A	85.1	183.0
Fuel Channel Life Mgmt Proj. (OM&A) ($M)[1]	8.8	6.2	1.7	0.9	0.2	2.6	17.8
Total Costs ($M)	**63.9**	**49.0**	**38.9**	**48.8**	**0.2**	**87.7**	**200.7**
Generation Impact (Planned Outage Days)	119	53	64	40	N/A	104	276
Generation Impact (TWh)	-1.5	-0.7	-0.8	-0.5	N/A	-1.3	3.5

Note 1: This is the Pickering station's share of the Fuel Channel Life Management Project's costs

This assessment also includes the assumption that Pickering Unit 7 will be life-managed in order to match its life to that of Pickering Unit 8 in both the No Continued Operations Case and in the Continued Operations case, thereby allowing Units 1 and 4 to operate until the projected end-of-life of Pickering Unit 8.

Risks to being able to achieve Continued Operations fall into the following 3 main categories:

1. Technical/Fitness-for-service Risks: i.e. risk that a major component does not continue to meet fitness-for-service requirements (e.g. being unable to demonstrate that the pressure tubes continue to be fit-for-service based on established technical criteria).

   In order to manage the technical risks around the pressure tubes life, management launched the Fuel Channel Life Management Project (FCLM) in 2009 and has made good progress on addressing any technical issues which are required to be resolved. Compared to early 2010 when the FCLM project was in its early stages, management now has medium confidence with an improving trend that achievement of 247,000 EFPH will be possible.

2. Regulatory: i.e. risk that the proposed disposition is not accepted by the CNSC or that there is a change to regulatory limits resulting in OPG being unable to demonstrate continued compliance.

   In order to manage the regulatory risks, and as part of the FCLM project, management has consulted with the CNSC to get agreement on the techniques and process for demonstrating the fitness-for-service of the pressure tubes. A protocol agreement has been established with the CNSC which identifies the 18 deliverables to be completed to demonstrate that pressure tubes will be fit for service up to at least 247,000 EFPH. Management believes that the regulatory risk is reduced compared to the 2009 assessment and issues will be manageable.

3. Economic: e.g. risk that a previously unknown issue is discovered leading to expensive repair costs and early shutdown of the units.

   In order to manage the economic risks, OPG has implemented a program of increased inspections and continues to monitor operating experience from other units and industry reports. Specific to Pickering Units 5-8, OPG has included additional maintenance work in the Continued Operations plan to reduce the likelihood of technical issues developing. Also, a phased approach to the release of funds is being taken. In addition, during the assessment of the business case for the refurbishment of Pickering B, a comprehensive plant condition assessment was completed. With the exception of the fuel channel issues mentioned above, there were no technical issues identified that would preclude operation to 247,000 EFPH. The risk of a discovery issue resulting in the non-achievement of Continued Operations is low and is reduced relative to the previous assessment in 2009.

Management continues to assess the risks associated with this initiative as manageable. Management assesses the overall confidence of achieving this initiative as medium with an improving trend.

2. SIGNATURES

Submitted by:

31MAY2012
Glenn Jager Date
Senior Vice President, Pickering

Recommended by:

2012-06-08
Wayne Robbins Date
Chief Nuclear Officer

Finance Approval :

July 10/12
Donn Hanbidge Date
Chief Financial Officer

Line Approval:

2012-07-22
Tom Mitchell Date
Chief Executive Officer

3. BACKGROUND & ISSUES

In June 2006, the Minister of Energy directed OPG to assess the feasibility of refurbishing its existing Pickering 5-8 nuclear units and to begin an Environmental Assessment in support of refurbishing and continuing to operate Pickering Units 5-8.

OPG's feasibility assessment for refurbishment consisted primarily of a Plant Condition Assessment, an Environmental Assessment and an Integrated Safety Review, as well as, development of conceptual level refurbishment project costs and an economic feasibility assessment. As a part of the feasibility assessment, OPG also explored the continued operation of the Pickering 5-8 units beyond their originally assumed operating lives. This assessment indicated the potential to operate the units for an additional four or more years beyond their originally assumed operating lives.

The originally assumed end-of-service life for the Pickering 5-8 units was based on the original design life of the key major component, i.e. fuel channels, and was projected to be when the units reached nominally 210,000 equivalent full power hours (EFPH). 210,000 EFPH are equivalent to 30 years operation at approximately 80% capacity factor. With Pickering Units 5-8 having come into service in the 1983 - 1986 period, the originally assumed end of life of these units was projected to be in the 2014 to 2016 period.

The decision on whether a nuclear unit is at the end of its operating life is primarily an economic one, as life limiting components can be replaced, and physical and procedural modifications implemented to ensure that the units are safe to operate and meet current regulatory codes and standards, if it is economically feasible to do so. For Pickering Units 5-8, the technical life-limiting major components are the fuel channels. This technical life limit is reached when continued fitness-for-service of the leading fuel channels can no longer be assured.

In February 2010, OPG announced that it would not pursue refurbishment of Pickering Units 5-8, but would implement programs to enable the continued operation of the plant until approximately 2020. The continued operation of Pickering Units 5-8 was assessed to be an economically attractive option for the Ontario electricity system. In addition, given the upcoming expected major refurbishment projects on the provincial fleet of nuclear units, OPG assessed that achievement of Continued Operations would provide significant flexibility to the Ontario electricity system in managing potential capacity issues in the 2014 to 2020 period.

In the original business case for continued operation of Pickering Units 5-8, approved in early 2010, OPG identified a work program and associated costs required to provide confidence in the achievement of continued operation for 4 years or more beyond the units' originally assumed operating lives. The development of a regulatory strategy was also part of this work program. During 2010 to 2012, implementation of this work program has progressed.

Major Components

A significant focus of the work program was to better understand and address any risks around major components and to ensure that appropriate activities were built into the Continued Operations planning scenario to mitigate those risks. Some of the key issues with the major components and the balance of plant at Pickering Units 5-8 are discussed in the following sections. More details on the key risks and risk mitigation activities are provided in Appendix A. Each risk is also rated in terms of the confidence that these risks can be successfully mitigated.

Fuel Channels (Pressure Tubes)

Aging mechanisms affecting the pressure tubes are closely monitored by OPG technical staff and the results of that monitoring are subject to regulatory oversight. Aging mechanisms include changes in the physical dimensions of the pressure tubes and the ingress of hydrogen into the pressure tubes. A major factor in aging is the presence of hydrogen, which increases with operating time, leads to an increased potential for defect formation (if pressure tube to calandria tube contact exists) and aging of the material properties of the pressure tubes with time. Thus, OPG must ensure that the concentration of hydrogen in the pressure tubes is monitored and is below specified values.

Management has undertaken a comprehensive project, the Fuel Channel Life Management Project, in co-operation with Bruce Power and with Atomic Energy of Canada Ltd., and coordinated through the CANDU Owners Group, in order to progress the technical and regulatory issues which are required to be resolved pertaining to fuel channels.

The highest priority for assuring the integrity of the pressure tubes in Pickering Units 5-8 is to avoid contact between the pressure tubes and calandria tubes. This requires ensuring that the spacers between the calandria tubes and pressure tubes are in the correct positions to ensure that there can be no contact. The spacers in Pickering Units 5-8 have been repositioned in an operation known as SLAR (Spacer Location and Relocation) to ensure that pressure tube to calandria tube contact up to 210,000 EFPH is precluded. In order to preclude pressure tube to calandria tube contact until at least 247,000 EFPH, an assessment was done to determine the number of channels which would need to be "Re-SLARed". In addition, once spacers are repositioned, there is a need for "re-visits" to the channels to monitor whether the spacers have moved. As well, measurements of the gap between the pressure tubes and the calandria tubes are now being performed. The work program for Continued Operations includes outage plans for the SLAR work, the re-visits and the gap measurements.

The next most important aging issue which is being managed is the effect of hydrogen ingress on fracture toughness of the pressure tubes. OPG's Fuel Channel Life Management Project includes significant laboratory work to: a) test irradiated material hydrided to high hydrogen levels to prove the toughness of the material, and b) improve the modelling of hydrogen ingress rates in order to improve the uncertainty around predictions of hydrogen levels. Work to date on this aspect of the work program is yielding results which are helping OPG to improve its life management of the pressure tubes in Pickering 5 - 8.

A third issue being managed is known minor defects on pressure tubes; the CNSC has agreed that this issue is of lower priority for Pickering Units 5-8 than the previous two issues. These minor defects, which are known to have occurred during commissioning activities, are being closely monitored. The impact of defects is to limit the number of thermal cycles on the pressure tubes (heat-up/cool-down). OPG has monitored these known defects for a number of years and has worked with the CNSC to gain acceptance of a methodology for characterizing the risks around known defects. Currently, the number of thermal cycles on each unit is not life limiting.

The risk table in Appendix A contains some additional details of pressure tube aging mechanisms and potential risks.

Steam Generators

The steam generators in the Pickering 5-8 units produce the steam used to drive the turbine-generator set. The tubes in the steam generators serve as a containment boundary as there is hot, pressurized heat transport fluid (heavy water) on the inside of these tubes.

The steam generators in Pickering Units 5-8 have performed well for several years. Among the known aging mechanisms being managed is under-deposit pitting/corrosion of the steam generators tubes. The Pickering Units 5-8 Continued Operations work scope includes adoption of an enhanced maintenance regime where warranted. This regime includes increased water-lancing to remove deposit build up on the steam generator tube sheets as well as more comprehensive inspections of the steam generator tubes. The Pickering Units 5-8 steam generators have been assessed to have a high probability of continuing to perform reliably during the Continued Operations period and beyond.

Feeders

The feeder pipes in a nuclear unit transport the heat transport fluid from the pressure tubes in the reactor to a common outlet header from which the fluid is piped to the steam generators and then back from the steam generators via an inlet header to the pressure tubes in the reactors in a closed loop. The primary aging mechanism of concern for the feeders is wall-thinning due to flow assisted corrosion.

As the units age, additional feeders will require replacement as they approach the limit of fitness-for-service due to flow assisted corrosion. The Pickering Units 5-8 Continued Operations work scope includes an assessment of the number of feeders which will require replacement during the continued operations period as well as the requirements for on-going inspections. Feeders in Pickering Units 5-8 have been assessed to have a high probability of operating reliably during the Continued Operations period and the projected number of replacements is manageable.

Reactor Components

Reactor components include the calandria vessel, the calandria tubes, the reactivity mechanism guide tubes, moderator relief ducts, and calandria external components such as end fittings, reactivity mechanism drives and cables and moderator inlet pipes. While some aging mechanisms are known, there is limited inspection history within the CANDU industry on many of these components.

Inspections were carried out during 2008 and 2009 in order to better understand the risks. One aging mechanism for which inspections are necessary during the next several years involves potential calandria tube / Liquid Injection Shutdown System (LISS) nozzle contact. The results from the first inspection in Unit 7 were favourable. Further inspections will be carried out to verify that this is not an issue for Continued Operations.

Risks will remain during the Continued Operations period that aging of some reactor components is taking place which could cause outages. To mitigate these risks, information is being gathered through industry-wide projects being undertaken by the CANDU Owners' Group (COG). Also operational experience is being gathered from other refurbishment projects, e.g. results of calandria internals inspections at the Bruce A and Pt. Lepreau stations, and these inspections have not revealed any unanticipated degradation mechanisms.

The Pickering Units 5-8 Continued Operations work scope includes an assessment of the work required to gain greater confidence in the condition of reactor components and the potential risks to reliability of the plant in the Continued Operations period. There is high confidence that reactor components will continue to operate reliably during the Continued Operations period.

Balance of Plant

A detailed Component Condition Assessment (CCA) of 70 systems, major structures and major components in the Pickering 5-8 units was completed in the first half of 2007.

The recommendations from these CCAs were assessed to determine the potential impact on costs and reliability in the Continued Operations period. The conclusion of the assessment was that, with the implementation of increased preventive maintenance programs and additional inspections, there would be minimal risks to equipment reliability over the Continued Operations period. Electrical and motor maintenance are examples of balance of plant work for which incremental funding has been included.

Other Issues:

Impact on Pickering Units 1 and 4 Operation

The current predicted end-of-service lives for Pickering Units 1 and 4 are the end of 2021 and 2027 respectively, if independent operation from Pickering Units 5-8 were feasible. However, Pickering Units 1 & 4 operation is linked to Pickering Units 5-8 through shared common systems and in particular, power supplies to special safety systems. As a result, significant modifications to systems to address this issue would be required to facilitate the operation of Pickering Units 1 and 4 in the absence of Pickering Units 5-8. In addition to addressing the technical issues, these modifications and other mitigation actions would need approval by the CNSC. OPG's assessment is that, without these modifications, two units of the Pickering 5-8 units must be in operation in order to support the operation of Pickering Units 1 and 4.

While it is technically possible to implement modifications to permit Pickering Units 1 and 4 to operate independently of the Pickering 5-8 units, the costs would be prohibitively high and would significantly impact the system value.

Impact on Financial Outlook

Successful achievement of high confidence in Continued Operations for Pickering Units 5-8 would result in a decrease in annual depreciation expenses for these units. As of January 1, 2013, OPG plans to change depreciation dates for the Pickering units to 2019-2020 in accordance with the expectation that high confidence of achieving Continued Operations will be achieved (Pickering Units 5-8 are currently being depreciated to 2014 and Pickering Units 1 and 4 to 2021).

4. ALTERNATIVES AND ECONOMIC ANALYSIS

Alternatives

The alternatives being analyzed are:

(i) plan to operate Pickering Units 5-8 to 210,000 EFPH on the pressure tubes, then shut down the units (last unit shutdown in 2016); and
(ii) plan to operate the units to approximately 247,000 EFPH before the units are shutdown (last unit shutdown in 2020).

In order to have two of Pickering Units 5-8 in operation to support Pickering Units 1 and 4, both of these alternatives include an assumption of "life management" outages on Pickering Unit 7 in order to achieve the objective of aligning its life with that of Pickering Unit 8.

ALTERNATIVE 1 –ORIGINALLY ASSUMED LIFE CASE – NOT RECOMMENDED:
Plan to Operate all Pickering 5-8 Units until 210,000 EFPH on the pressure tubes. Implement life management outages in 2013 and 2014 on Pickering Unit 7 to keep that unit operating to the forecast end-of-life of Pickering Unit 8 in order to support operation of Units 1 and 4.

In this alternative, the current program to enable Continued Operations of Pickering Units 5-8 would cease. Work would cease on the incremental inspections, maintenance, analytical or regulatory work programs which have been in place to enable continued operation of the units beyond

210,000 EFPH. The originally assumed predicted end-of-life dates for the Pickering 5-8 units would be Q2 2014 for P6, Q4 2014 for P5, Q2 2016 for P7 (with the life management outages implemented) and Q2 2016 for P8. Pickering Units 1 and 4 would also be shutdown in Q2 2016, co-incident with the shutdown of Units 7 and 8.

ALTERNATIVE 2 - CONTINUED OPERATION TO 247,000 EFPH - RECOMMENDED

Plan to operate all Pickering 5-8 Units until 247,000 EFPH on the pressure tubes. Implement life management outages on Pickering Unit 7 to keep Pickering Unit 7 operating to the end 2020 along with Pickering Unit 8 in order to support operation of Units 1 and 4.

In this alternative, the incremental inspections, maintenance, laboratory testing, analytical work and regulatory strategies would continue in order to continue to drive towards high confidence of achieving continued operation of Pickering Units 5-8 to at least 247,000 EFPH. In addition, life management outages would be implemented to continue to operate Pickering Unit 7 to the end of 2020, along with Pickering Unit 8 in order to have the station in a configuration which would support the operation of the Pickering Units 1 and 4 until the end of 2020.

The continued operations predicted end-of-life dates for Pickering Units 5-8 corresponding to 247,000 EFPH would be Q2 2019 for P6, Q1 2020 for P5, End 2020 for P7 (with life management outages implemented) and End 2020 for P8 (P8 would be shutdown at the end of 2020 prior to achieving 247,000 EFPH). Units 1 and 4 would be shut down co-incident with Units 7 and 8 at the end of 2020.

Economic Analysis

The identified incremental work, its associated costs and the impact on generation throughout the 2013-2020 period were assessed.

For Alternative 1, 2012-2014 Business Plan costs and performance, excluding the Continued Operations work, costs and generation impacts, were used and extrapolated where required to originally assumed end-of-life dates (2014/2016).

For Alternative 2, 2012-2014 Business Plan costs and performance, including the Continued Operations work, costs and generation impacts, were used and a long-term planning forecast was used for the period 2015 to 2020. The Continued Operations costs and performance impacts included such items as the costs of SLAR and Re-SLAR and enhanced boiler water-lancing costs, as well as the increased planned outage days resulting from the implementation of this work. The benefit is the value of the energy from Pickering Units 1, 4, and 5-8 during the extended operating period.

The business plan and long-term forecast costs allocated to Pickering 1, 4 and 5-8 were modified for the purposes of the economic analysis to include only the assessed incremental portion of the costs allocated to Pickering, e.g. Nuclear Support and Corporate Support costs. OPG uses incremental costs based on the following premises:

a) That there are economies of scale in the provision of Nuclear and Corporate Support to a large fleet of stations,
b) That there are some "centrally held costs" allocated by Corporate to each station that are purely "fixed", i.e. are not affected by a decision to continue or not continue to operate a station.

OPG assesses that, as the nuclear fleet shrinks, i) losses of economies of scale will result in an effective increase in the cost per unit of providing Nuclear & Corporate support services to the remaining stations, and; ii) that the "Fixed Overheads" currently allocated to a larger fleet of stations will effectively need to be re-allocated to a smaller fleet, resulting in the allocation of "Fixed Overheads" to the remaining stations increasing. See Appendix D for more discussion of this topic.

Net present values (NPV) of the alternatives were calculated based on forecast costs and performance of the Pickering units and based on OPG's assessment of the value of the incremental energy and capacity to the Ontario system. The value of the Continued Operations Alternative was calculated relative to the Originally Assumed Life Alternative (Alternative 1) by subtracting the NPV (PV of benefits minus costs) of Alternative 1 from the NPV of the Alternative 2.

The economic assessment results showed an incremental NPV of $520M (2012$) to the Ontario electricity system for additional energy and capacity from Pickering Units 1,4 and 5-8 for Alternative 2 when compared to Alternative 1. Certain economic impacts have not been included such as a positive NPV impact on the decommissioning liability for Pickering Units 5-8 and NPV savings to the ratepayer due to the deferral of transmission system upgrade costs which OPG understands will be required when Pickering is shutdown. Results of the economic assessment are shown in Table 1 below:

Table 1: Summary of Economic Results of Alternatives

	Alternative 1 P6 S/D in 2014; P5 S/D at end 2014 P1,4,7/8 S/D in 2016	**Alternative 2** P6S/D in 2019; P5 S/D in 2020 P1,4, 7/8 S/D at end 2020
Incremental Cost ($M)	N/A – Base Case	$88M
Impact on Economic Value (2012$M, PV)	**N/A – Base Case**	**$520M**

Results of the economic assessment were tested for sensitivity to key inputs such as:

(i) assumed electricity value
(ii) valuation of exports resulting from continued operation
(iii) the length of continued operation life achieved
(iv) generation performance
(v) overall costs of operating the Pickering units
(vi) costs of the incremental work to enable Continued Operations.

Figure 2 shows the results of some of the key sensitivity analyses performed.

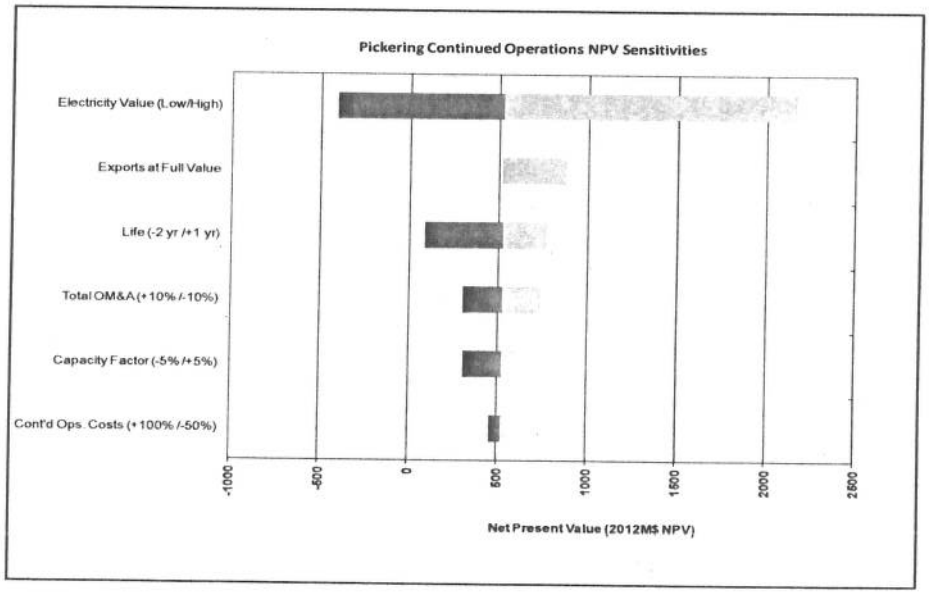

Figure 2: Results of Key Sensitivity Analyses

The sensitivity analysis shows that the expected value is most sensitive to the expected value of electricity on the system, somewhat sensitive to the valuation of exports from Ontario to neighbouring jurisdictions (caused by the availability of Pickering), somewhat sensitive to the costs of operating the Pickering station, the life achieved and the capacity factor achieved, and insensitive to the cost of the incremental Continued Operations work. All values are in 2012 PV$.

With regards to the assumed electricity value, in a high value regime, the incremental value of the output from the Pickering units the Continued Operations period could be as high as $2.2B PV. In a low value regime, the Continued Operation of the Pickering units could result in an increased system cost of $410M PV over the Continued Operation period. A low value regime could result if there is such a low demand for electricity that much of the generation currently on the system (not just Pickering) would be surplus to needs. In addition, the low value scenario assumes that gas prices would have declined further from the current prices.

The expected value is somewhat sensitive to the total cost of operating the Pickering station. For example, if the total incremental OM&A Costs at Pickering could be improved by 10%, there would be an incremental additional value of approximately $220M PV (total value of $740M PV) created. Similarly, if OM&A costs were to worsen by 10%, then the incremental value would be worse by approximately $220M PV.

The expected value is also somewhat sensitive to the Continued Operations life achieved. If 2 fewer years of Continued Operation life were achieved, there would be a reduction in the expected value of approximately $435M PV to a value of approximately $85M PV while, if 1 additional year of life were achieved, the value would increase by approximately $245M to approximately $765M PV.

The expected value was also tested for a range of assumed performance on the units. If the capacity factor were to be lower by 5%, the impact on the value is a reduction of approximately $215M PV to approximately $305M PV. If a 5% higher capacity factor were to be achieved, the impact on the value is an increase of $75M to approximately $595M PV.

A doubling of the costs of all of the work required to enable Continued Operations reduces the value of Continued Operations by approximately $60M PV to approximately $460M PV, while a halving of the costs increases the value of Continued Operations by $30M PV to approximately $550M PV.

The $520M (2012$PV) represents OPG's central estimate for the 247,000 EFPH case with Pickering Units 7, 8 1& 4 operating to the end of 2020. These estimates differ from the previous assessment (completed in 2009) of $1.1 B (2009$PV) for the 240,000 EFPH case. There are multiple reasons for the change in assessed value. The key reasons are listed in the table below in approximate order of impact on the results:

	Reason for Change	Approx. Impact on Results (2012 M$ PV)
1.	Impact of change from 2009 PV$ to 2012PV$ (& removal of Continued Ops costs and production impacts in 2009-2012)	+ $250M
2.	Lower demand forecast/ lower replacement generation costs (lower gas prices) compared to the previous assumptions; this affects the value of Pickering's generation to the system.	- $1190M
3.	Change from 240,000 EFPH to 247,000 EFPH	+ $330M
4.	Updated Pickering Costs	+ $240M
5.	Changed methodology for Valuing Exports	- $355M
6.	Other Assessment Methodology & Assumption Changes	+$140M

5. THE PROPOSAL

1. Continue to execute the Continued Operations program, i.e. pressure tube inspections, Spacer Location and Relocation campaigns, boiler maintenance and inspections and other work to preserve the option to continue to operate Pickering Units 5-8 until at least 247,000 EFPH

   The work to be completed in the Continued Operations work program and the current estimated costs are summarized in Appendix C.

   The estimates, shown in Appendix C, with the exception of those shown for the Fuel Channel Life Management Project, do not include explicit contingency. These costs are to be incurred in the near term, the work is well understood and the estimates of business plan level quality, thus OPG does not expect that there will be cost overruns and, therefore, has not allowed for any explicit contingency in these estimates.

6. QUALITATIVE FACTORS

Deferral of Potential Staff Reductions

The achievement of Continued Operations creates greater opportunities to smooth the redeployment of Pickering direct and support staff to Darlington refurbishment, Darlington operations, as well as to the Darlington New Nuclear project and operations, if that project proceeds.

Socio-Economic Impacts

Pickering Nuclear is a major employer within Durham Region. In 2009, approximately 2,700 people were directly employed at PNGS A and PNGS B. Pickering Nuclear and associated OPG facilities contribute significantly to the tax base of the City of Pickering.

Pickering Nuclear has attracted nuclear related businesses, helping to establish a Durham Energy Industry Sector Cluster (e.g. Eastern Power, Eco-tech, Black and MacDonald, AREVA, New Horizons Systems Solutions, etc.). Continued operation of Pickering Units 1, 4 and 5-8 defers the impacts of the shutdown of Pickering on the Durham Region by approximately 5 years.

Air Emissions

If the Pickering plant were not in service there would be a greater demand for gas-fired replacement generation during the period 2014 to 2020 to meet the electricity system load, with the associated impacts on air emissions. Compared to nuclear, which has been assessed to have life cycle emissions of 4 to 31 g/kWh of carbon dioxide (CO_2), Combined Cycle Gas Turbines (CCGT) have been assessed to have 325 to 519 g/kWh life-cycle emissions of CO_2, and 300 to 400 g/kWh based on combustion only. Continued operation of Pickering lessens the use of gas-fired replacement generation to meet the electricity system load in the 2014 to 2020 period.

Impacts on Decommissioning Liability

The decommissioning liability for Pickering Units 5-8 was established based on shutdown dates in the 2013 to 2015 period and, for the Pickering 1 and 4 units, based on a shutdown date of 2021. As of January 1, 2012, OPG will adjust its decommissioning liability for the Pickering station, based on shutdown dates consistent with Alternative 2. The combined effect of these changes results in an effective reduction in the decommissioning liability of approximately $125 million, all other factors remaining unchanged.

Transmission Impacts

A number of issues would need to be addressed when Pickering Units 1, 4 and 5-8 are retired, including replacement supply, capacity of the Cherrywood transformers and the 230 kV system, system voltage support and security risk. Due to its importance to the GTA system, the transmission changes required would be complex and extensive. Such a decision would remove up to 3,000 MW (including Pickering Units 1 and 4) of internal generation from the GTA. The combination of a third 500 kV supply line to the Parkway Transformer Station (TS) and the Oshawa Area TS could address the Pickering Units 5-8 retirement from a transmission supply perspective. However, the additional loss of the Pickering 1 and 4 units would necessitate a review of generation development in the area as well as area load supply, possibly in the form of a third major supply line to Toronto.

Based on OPA plans, the development of the Oshawa Area TS (approximately $300M) would be required to be advanced from the 2018-2020 timeframe to the 2014-2016 timeframe if the Pickering units were to shutdown on the "Originally Assumed Life" dates.

These advancements of transmission infrastructure improvements have a net present value impact and are an additional benefit of Pickering Continued Operations.

7. RISKS

Risks to being able to achieve Continued Operations of the Pickering 5-8 units fall into the following main categories:

1. Technical/Fitness-for-service Risks: i.e. risk that a major component does not continue to meet fitness-for-service requirements (e.g. being unable to demonstrate that the pressure tubes continue to be fit-for-service based on established technical criteria).

   In order to manage the technical risks around the pressure tubes life, management launched the Fuel Channel Life Management Project (FCLM) in 2009 and has made good progress on addressing any technical issues which are required to be resolved. Compared to early 2010 when the FCLM project was in its early stages, management now has medium confidence with an improving trend that achievement of 247,000 EFPH will be possible.

2. Regulatory: i.e. risk that the proposed disposition is not accepted by the CNSC or that there is a change to regulatory limits resulting in OPG being unable to demonstrate continued compliance.

   In order to manage the regulatory risks, and as part of the FCLM project, management has consulted with the CNSC to get agreement on the techniques and process for demonstrating the fitness-for-service of the pressure tubes. A protocol agreement has been established with the CNSC which identifies the 18 deliverables to be completed to demonstrate that pressure tubes will be fit for service up to at least 247,000 EFPH. Management believes that the regulatory risk is reduced compared to the 2009 assessment and issues will be manageable.

3. Economic: e.g. risk that a previously unknown issue is discovered leading to expensive repair costs and early shutdown of the units.

   In order to manage the economic risks, OPG has implemented a program of increased inspections and continues to monitor operating experience from other units and industry reports. Specific to Pickering Units 5-8, OPG has included additional maintenance work in the Continued Operations plan to reduce the likelihood of technical issues developing. Also, a phased approach to the release of funds is being taken. In addition, during the assessment of the business case for the refurbishment of Pickering B, a comprehensive plant condition assessment

was completed. With the exception of the fuel channel issues mentioned above, there were no technical issues identified that would preclude operation to 247,000 EFPH. The risk of a discovery issue resulting in the non-achievement of Continued Operations is low and is reduced relative to the previous assessment in 2009.

8. POST IMPLEMENTATION REVIEW

The strategic work outlined in this Business Case is intended to provide greater certainty in the achievement of Continued Operations for Pickering Units 5-8. The progress of Continued Operations, including the incremental work and expenditures required, is re-assessed annually as part of the business planning process.

Appendix A: Summary of Key Technical, Regulatory, Reputation and Economic Risks Associated with Continued Operations

Risk Description	Consequence	Mitigation Strategy	Impact on Continued Operations	Prob. of Success (Very High, High, Medium, Low, Very Low Unknown	Industry issue or unique to Pickering 5-8?
Technical Risks – Pressure Tubes					
Pressure tube to calandria tube contact	Potential for defect formation	**Technical:** SLAR all channels to 247k EFPH. SLAR revisits to address potential for post-SLAR spacer movement. Currently, the risk is being managed by probabilistic assessments and targeted revisits.	Additional planned outage days in Generation Plan to execute SLARs and SLAR "re-visits" to assure contact-free operation to 247,000 EFPH.	2yrs - High 5 yrs – Med-High	Unique to Pick 5-8 and some other Candu units.
Pressure tubes - hydrogen ingress to body of tube and rolled joint	Embrittlement of pressure tubes	**Technical:** Sampling of P/Ts (Scrape) to trend ingress rates. Laboratory testing to demonstrate P/T integrity at higher hydrogen concentrations **Regulatory:** Provide evidence to regulator to obtain increased limits	Potential additional time in outages to conduct sampling activities. If limits cannot be changed, potential to exceed limits near end of Continued Operations period	2yrs - High 5 yrs – Med-High	Industry
Pressure tube defects	Defect growth	**Technical:** Monitor in-service defects every outage; manage heat up/cool down cycles **Regulatory:** Gain acceptance of new assessment methodologies	Potential need to extend forced outages to inspect and disposition defects.	2yrs – Very High 5 yrs – Very High	Industry, but problem more acute for Pickering 5-8 due to higher flaw population
Technical Risks –Reactor Components					
Calandria tube defects	Leaking calandria tubes – unit shutdown	**Technical:** Tooling, procedures and capability are in place in the event of future failures.	Judged to be low probability based on P7A13 root cause assessment.	2 yrs – Very High 5 yrs - High	Industry
Liquid Injection Shutdown System Nozzle / Calandria tube contact	Leaking calandria tubes – unit shutdown	**Technical:** Follow-up inspections in upcoming outages and replacements of fuel channels if required. Tooling, procedures and capability are in place.	Could lead to a small number of pressure tube and calandria tube replacements.	2yrs – High 5yrs - High	Industry

Appendix A: Summary of Key Technical, Regulatory, Reputation and Economic Risks Associated with Continued Operations

Risk Description	Consequence	Mitigation Strategy	Impact on Continued Operations	Prob. of Success (Very High, High, Medium, Low, Very Low Unknown	Industry issue or unique to Pickering 5-8?
Other Calandria Internals (e.g.): • Guide tubes spring de-tensioning • Moderator Inlet Nozzles • Moderator relief ducts	Failure to demonstrate fitness-for-service	**Technical:** Operating Experience from Bruce Power and NB Power refurbishments Planned inspections in Pickering 1, 4, 5-8 and Darlington over the next several years. Information sharing with COG and establishment of industry-level Calandria Internals Life Management Guidelines	Unforeseen aging mechanisms can have significant implications.	2yrs – Very High 5 yrs –Very High	Industry
Technical Risks –Boilers					
Boiler tube leak • Under deposit pitting / corrosion	Unacceptable number of boiler tube defects	**Technical:** Increased water lancing and inspections where warranted	Release of tritium to the environment.	2yrs - High 5 yrs – High	Industry issue, but Monel 400 tubing material is unique to Pickering
Technical Risks –Feeders					
Feeders • Feeder thinning	Failure to demonstrate fitness-for-service.	**Technical:** Well established program of feeder inspections and replacements each outage.	Number of feeders tends to vary from year to year but the proposed number to be replaced does not impact the viability of the station.	2yrs - Very High 5 yrs – High	Industry (less of an issue at Pickering 5-8)
Technical Risks –Balance of the Plant					
Balance of Plant • Turbine/generator • Emergency Power Generators • Screenhouse • Electronic components	Possible derates or forced outage.	**Technical:** Combination of maintenance strategies, life cycle and project upgrades will ensure equipment is kept available.	Incremental costs, forced loss rates and outage delays	2 yrs - High 5 yrs - High.	Industry issues,

Appendix A: Summary of Key Technical, Regulatory, Reputation and Economic Risks Associated with Continued Operations

Risk Description	Consequence	Mitigation Strategy	Impact on Continued Operations	Prob. of Success (Very High, High, Medium, Low, Very Low Unknown	Industry issue or unique to Pickering 5-8?
Regulatory Risks					
Integrated Safety Review (ISR) and Environmental Assessment (EA) (Mandated Upgrades to support continued operation) • Fish Impingement & Entrainment • Effects of Thermal Plume • CCA upgrades • Safety Analysis / ISR	Fish Impingement and Entrainment and thermal discharges are being addressed. Selected ISR Gaps will be required to be addressed.	**Technical:** Modifications implemented to address fish impingement. On-going monitoring required. Work required to offset entrainment losses. **Regulatory:** Work underway with the CNSC to fully define potential requirements and closure criteria for ISR gaps. A plan to assess and address thermal plume mitigation is being developed.	May impact Base OM&A costs	2 yrs- High 5 yrs - High	Industry issue, but Pickering is more affected due to the design of the intake and outfall structures
Regulator acceptance of the fitness-for -service approach to determining station end-of-life.	Regulatory attention; (for safety analysis, potential derates due to reduced operating margin is possible).	Work with regulator to continue to get acceptance to fitness-for-service approach through the Fuel Channel Life Management Project and updates as required to the protocol which has been agreed to as part of that project. Continue to work with the Regulator to ensure OPG can meet requirements.	Potential Inability to obtain regulator acceptance could impact site work program prior to end of Continued Operations period.	5 yrs - High	Industry issue, but Pickering 5-8 may be the focus due to the timing of the re-licensing.
Scope / Economic					
Unforeseen major equipment failure,	Major outages for repairs or shutdown of a unit or entire plant prior to expected duration of continued operations period.	**Technical:** Where possible, perform inspections of equipment which fall into the category of potential life limiting; where not possible, continue to monitor OPEX from other units and refurbishment projects and sponsor industry technical assessments. **Economic:** Implement a phased funding strategy (minimize incremental investments in Continued Operations) until greater technical and regulatory certainty can be achieved.	Outages for unforeseen repairs or shutdown of a unit.	2 yrs – Very High 5 yrs – High.	Industry

For Internal Project Cost Control

APPENDIX B: Impacts on Generation of Pickering Continued Operations

Cont. Ops Work Program Impacts	2013	2014	2015	2016	2017	2018	2019	2020	Total
Incremental Planned Outage Days - Cont Ops Work Program	64	40	n/a	n/a	n/a	n/a	n/a	n/a	104
Portion of Incremental/Decremental TWh due to Cont Ops Work Program	-0.8	-0.5	n/a	n/a	n/a	n/a	n/a	n/a	-1.3
Total Incremental/Decremental TWh for Pickering Cont Ops.	1.3	4.7	4.6	16.6	22.6	21.9	20.3	17.2	109.3

APPENDIX C: Cost Summary

ONTARIO POWER GENERATION	Summary of Estimate	Date	April 20, 2012
		Project #	NA

Facility Name:	Pickering
Project Title:	Pickering Continued Operations

Estimated Costs in $Million of the Year

Work Program	LTD 2009 - 11	2012 Proj	2013	2014	2015	Totals
Component Improvements (CCA non-major components)	27.5	18.9	19.3	18.4	N/A	84.1
Life Cycle Management (Including New Scope) e.g. SLAR	5.3	6.0	8.7	8.6	N/A	28.6
Inspection Programs	0.8	2.5	2.7	2.4	N/A	8.4
Other Planned Outage Activities	14.1	8.0	5.0	5.0	N/A	32.1
Feeder Replacements	0.0	0.0	0.0	7.7	N/A	7.7
Enhanced Water Lancing	4.4	4.2	0.0	4.2	N/A	12.8
Spares	0.0	2.2	0.5	0.5	N/A	3.2
Minor Modifications	3.1	1.0	1.0	1.0	N/A	6.1
Total	**55.2**	**42.8**	**37.2**	**47.9**	**N/A**	**183.0**

Fuel Channel Life Management Project	$8.8	$6.2	$1.7	$0.9	$0.2	**$17.8**

Prepared by:

Director, Business Support

Approved by:

Site Vice President, Pickering

APPENDIX D: Financial Modelling – Assumptions

Cost Assumptions:

1. Base OM&A, Capital and OM&A projects, and Outage OM&A costs for Pickering Units 5-8 are consistent with the 2012-2014 Business Plans for those stations. These costs were extrapolated to the period 2015-2020.
2. Incremental costs for Pickering Continued Operations are as shown in Appendix C.

Use of Incremental Costs in Economic Analyses

Direct Station Costs, Fuel and Fuel Related costs are directly linked to station operation and are, therefore, all considered incremental costs to operate a nuclear station. However, only a portion of the Nuclear Support and Corporate Support costs which are allocated to a nuclear station are treated as incremental, based on the following premises:

a) That there are economies of scale in the provision of Nuclear and Corporate Support to a large fleet of stations,
b) That there are some "centrally held costs" allocated by Corporate to each station that are purely "fixed", i.e. are not affected by a decision to continue or not continue to operate a station.

OPG assesses that, as the nuclear fleet shrinks, i) losses of economies of scale will result in an effective increase in the cost of providing Nuclear & Corporate support services to the remaining stations, and; ii) that the "Fixed Overheads" currently allocated to a larger fleet of stations will effectively need to be re-allocated to a smaller fleet, resulting in the allocation of "Fixed Overheads" to the remaining stations increasing.

The assessment done for the "incremental" view of Nuclear Support costs for the 2010 BCS showed that approximately 70% of the "fully allocated" nuclear support costs to the Pickering units were incremental, i.e. losses of economies of scale would result in the remaining 30% effectively translating to increased support costs for Darlington. OPG has updated and refined that assessment for the 2012 BCS, and has used a revised estimate (averaging 68% over the period 2013 - 2020) as to portion of the Nuclear Support costs allocated to Pickering which would be incremental, i.e. would go away of the Pickering units were to be shut down.

Similarly, the "incremental" view of Corporate Support & Overhead costs for the 2010 BCS showed that approximately 30% of the "fully allocated" Corporate Support costs allocated to the Pickering units were truly incremental, i.e. losses of economies of scale would result in the remaining 70% effectively translating to increased Corporate Support & Overhead costs for the rest of OPG's fleet of nuclear, thermal and hydroelectric stations. OPG has updated and reined that assessment for the 2012 BCS, and has used a revised estimate (averaging 28% over the period 2013 - 2020) as to portion of the Corporate Support costs to Pickering which would be incremental, i.e. would go away of the Pickering units were to be shut down.

Financial Assumptions:

1. Cost escalation rates used are consistent with those used in economic assessments and in Business Planning in OPG for labour, material and purchased services.
2. A nominal discount rate of 7% was applied in all analyses.

Operating Life Assumptions:

1. An operating life of 210,000 Equivalent Full Power Hours (EFPH) for each of the Pickering 5-8 units was used in the Originally Assumed Life Case. The Continued Operations Case was assessed at an operating life of 247,000 EFPH.

2. Sensitivities on operating life were done at 233,000 EFPH and 254,000 EFPH, i.e. nominally for 3 and 6 calendar years of continued operations.

Energy Production Assumptions:

1. For the Base Case, energy production assumptions are consistent with the 2012-2014 Business Plan for Pickering Units 1, 4 and 5-8, but exclude the impact of outage extensions caused by completion of work associated with Continued Operations for Pickering Units 5-8.
2. For the Continued Operations Case:
   - » Energy production assumptions for the 2012 to 2014 period are based on the Business Plan for Units 1, 4 and 5-8, including the impact of outage extensions caused by completion of work associated with Continued Operations, i.e. the incremental planned outage days. Post 2014, energy production levels were projected forward by the station planning staff, based on expected performance of the plant in that time period.
   - » Sensitivities on capability factors were performed for range of plus 5% to minus 5% around the nominal values.

Other Assumptions:

1. OPG 2011 median assumptions regarding future Ontario system development, gas prices, etc, were used as the bases from which to evaluate the value to the Ontario electricity system. Sensitivities were run for a number of scenarios which would lead to, for example, a Low Priced regime and also a High Priced regime.
2. For the both the Originally Assumed Life Case and the Continued Operations Case, it was assumed that life management of Pickering Unit 7 would be implemented in order to be able to operate that unit to the end of life date of Pickering Unit 8 (the unit with the longest remaining life) or to the end of 2020, whichever is sooner. This is to ensure that two Pickering 5-8 units are in operation in order to facilitate continued operation of Pickering Units 1 and 4 for as long as possible.