CONCENTRIC

*CONFIDENTIAL*

August 30, 2011

Mr. Charles Keizer
Torys LLP
Suite 3000
79 Wellington St. W.
Box 270, TD Centre
Toronto, Ontario
M5K 1N2 Canada

Dear Mr. Keizer:

On behalf of Concentric Energy Advisors, Inc. ("Concentric"), I would like to thank you for the opportunity to assist Torys, LLP ("Torys") respecting its advice to Ontario Power Generation, Inc. ("OPG") in the review of the Darlington Nuclear Generating Station refurbishment ("DRP"). Specifically, Concentric will provide an independent expert review of the DRP procurement strategies as outlined in our separate scope of work (Attachment A). This letter provides an introduction to Concentric, proposed commercial terms and the proposed project team. Additionally, I have included our previously discussed scope of services, billing rates, terms and conditions, résumés for the proposed project team, and a Concentric contact list as Attachments A – E, respectively.

## INTRODUCTION TO CONCENTRIC

Concentric is a regulatory, financial and economic advisory firm focused on the North American energy industry. Concentric specializes in a full range of regulatory and utility ratemaking advisory services; expert testimony and litigation support; market assessment and strategic consulting services; and financial and transaction-related advisory services. The firm's principals and affiliates have held executive positions with a number of prominent utility management consulting firms, utility companies, regulatory agencies, competitive energy suppliers and investment banks.

Concentric has unique experience and expertise in the nuclear power industry, providing advisory services to owners and operators of, and investors in, nuclear power plants in North America. Concentric's staff has been involved in these activities for more than 25 years, and therefore has a strong understanding of the unique financial, economic, managerial and regulatory issues that nuclear power plant development, construction, ownership and operation present.

## PROPOSED SCOPE

The scope of Concentric's services is specified in Attachment A.

## PROPOSED COMMERCIAL TERMS

Concentric will perform the services specified in Attachment A on a time and materials basis, at a [redacted] discount from our standard rates, which are included as Attachment B. Our direct expenses will be billed at cost and in accordance with OPG's Standard Form Business Expense Schedule, dated

July 27, 2010. A copy of the agreed upon terms and conditions can be found in Attachment C. Please note that all payments are to be made in U.S. dollars.

## PROPOSED PROJECT TEAM

Concentric will provide a highly experienced team to perform the services required by Torys. Mr. John Reed, Chairman and Chief Executive Officer, will serve as the Responsible Officer for the project. Mr. James Coyne, Senior Vice President, will serve as a Regulatory Advisor and Mr. Samuel Eaton will serve as the Project Manager. They will be assisted by Mr. Daniel Dane, Senior Project Manager; Mr. Steve Caldwell, Senior Consultant; Mr. Mark Cattrell, Senior Consultant; and Mr. James Kahler, Consultant. Résumés for these team members are included as Attachment D and a contact list is provided as Attachment E. Additional advisory, research and administrative resources may be utilized as necessary.

If the above terms are acceptable to you, please kindly execute and return to me, the signature pages of this letter and the agreed upon terms & conditions (Attachment C).

Concentric is looking forward to the opportunity to assist Torys and OPG.

Best regards,

**CONCENTRIC ENERGY ADVISORS, INC.**

John J. Reed

John J. Reed
Chairman and Chief Executive Officer

Enclosures:
Attachment A – Scope of Services
Attachment B – Concentric's Standard Rates
Attachment C – Standard Terms and Conditions
Attachment D – Résumés of Project Team Members
Attachment E – Concentric Contact List

**AGREED AND ACCEPTED:**

CLIENT SIGNATURE

TITLE: Partner

COMPANY: Torys LLP

DATE: Sept 5, 2011

# Scope of Services of Expert Reviewing Darlington Refurbishment Contracts and Strategy

The scope of services provided by Expert is expected to include:

- Assisting legal counsel to OPG (both internal and external counsel) in order for counsel to advise OPG with respect to its commercial contract and contracting strategy for the Retube and Feeder Replacement (RFR) contract and contracts for other major work packages for the Darlington refurbishment project.
- Reviewing information provided by OPG on its contract design strategy with respect to the RFR contract and other contracts, and providing an assessment as to whether that strategy is reasonable and prudent.
- Reviewing OPG's contracts proposed to bidding vendors for the RFR and other work, any other information provided by OPG in relation to it, and developing an opinion as to whether OPG's RFR contract is reasonable and prudent, and reasonably protects OPG's and its customers' interests.
- The Expert may also be asked to testify at the next OEB rate hearing, prepare interrogatory and undertaking responses, assist with preparation of argument, and participate in other facets of the hearing.
- In conducting its assessments, the Expert may have regard to the items that follow below.

Industry Practices and Strategy Employed

- Based on information from public sources, information provided to Expert by OPG, and based on the Expert's knowledge of similar contracting situations, what are industry practices and/or best practices for procurement of major power plant refurbishment and construction projects and specifically for procuring an RFR contract? How do such contracting practices vary for the Canadian marketplace, if different from the U.S. marketplace?
- Evaluate and summarize, with sufficient detail, OPG's procurement process that resulted in the final vendor contract.
- In determining its contracting strategy, what factors should OPG have considered? Factors in this regard may include for example, cost and schedule certainty as to key project elements, the potential for disputes about scope of services and responsibilities, and work package integration.

- What are the benefits and or drawbacks to the strategy that OPG employed, and how did these benefits get quantified?

ATTACHMENT B
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# CONCENTRIC ENERGY ADVISORS, INC.
# HOURLY RATE SCHEDULE

(EFFECTIVE AS OF 1/1/2011)

| TITLE | HOURLY RATE |
|---|---|
| CHAIRMAN AND CHIEF EXECUTIVE OFFICER | [redacted] |
| PRESIDENT | [redacted] |
| SENIOR VICE PRESIDENT | [redacted] |
| VICE PRESIDENT, EXECUTIVE ADVISOR | [redacted] |
| ASSISTANT VICE PRESIDENT | [redacted] |
| SENIOR PROJECT MANAGER | [redacted] |
| PROJECT MANAGER | [redacted] |
| SENIOR CONSULTANT | [redacted] |
| CONSULTANT | [redacted] |
| ASSISTANT CONSULTANT | [redacted] |
| ANALYST | [redacted] |
| ASSOCIATE | [redacted] |
| PROJECT ASSISTANT | [redacted] |

ATTACHMENT C
CONFIDENTIAL

# CONCENTRIC ENERGY ADVISORS, INC.
# TERMS AND CONDITIONS

1. *Scope* – Concentric Energy Advisors, Inc. ("Concentric") will perform the services set forth in the Letter or Proposal of which these Terms and Conditions (Terms) are a part. The provisions of these Terms shall control in the case of conflict with any provisions of the Letter or Proposal.

2. *Fees and Expenses* – Unless otherwise stated, fees for services by Concentric shall be based upon the rates, at the time the work is performed, of the personnel actually involved in the assignment, on the basis of the rates most recently communicated to, and accepted by, Torys. Report production and printing, reproduction, and telephone charges will be billed to you at Concentric's standard charges for such materials for services. Expenses of consultants while on assignment or any other charge incurred or expenditure made on your behalf will be charged at our cost.

3. *Payment* – Concentric will submit monthly invoices reflecting actual work performed and expenses incurred. Payment shall be due in U.S. funds 30 days after the date of an invoice. Amounts past due more than 30 days shall bear interest at an annual rate of [redacted] from the due date until payment is received.

4. *Sales Tax* – You are responsible for paying any local, state, or federal sales, use, or ad valorem tax that might be assessed on our services.

5. *Independent Contractor* – It is understood and agreed that Concentric shall for all purposes be an independent contractor, shall not hold itself out as representing or acting in any manner for you, and shall have no authority to bind you to any contract or in any other manner.

6. *Termination* – These terms shall be subject to the right of either party to terminate at any time upon not less than ten (10) days prior written notice to the other party. Upon termination, you shall pay the full amount due for services rendered and costs and expenses incurred and not paid for up to that time, and the costs of returning consultant personnel to home base and other reasonable costs and expenses incurred in effecting termination and returning documents.

7. *Responsibility Statement* – Concentric agrees that the services provided for herein will be performed in accordance with recognized professional consulting standards for similar services and that adequate personnel will be assigned for that purpose. If, during the performance of these services or within six months following completion of the assignment, such services shall prove to be faulty or defective by reason of a failure to meet such standards, Concentric agrees that upon prompt written notification from you prior to the expiration of the six month period following the completion of the assignment containing any such fault or defect, such faulty portion of the services shall be redone at no cost to you up to a maximum amount equivalent to the cost of the services rendered under this assignment. The foregoing shall constitute Concentric's sole liability with respect to the accuracy or completeness of the work and the activities involved in its preparation. In no event shall Concentric, its agents, employees, or others providing materials or performing services in connection with work on this assignment be liable for any direct, consequential or special loss or damage, whether

attributable to breach of contract, tort, including negligence, or otherwise; and except as herein provided, you release, indemnify, and hold Concentric, its agents, employees, or others providing materials or performing services in connection with work on this assignment harmless from any and all liability including costs of defense, settlement and reasonable attorney's fees.

8. *Work Product* – Any report or other document prepared pursuant to these Terms shall be for your use only. Concentric's prior written consent is required for the use of (or reference to) its report or any other document prepared pursuant to these Terms in connection with a public offering of securities or in connection with any other financing. Concentric hereby agrees, however, to the Client's reference to the work product in connection with any proxy relating to a combination between two parties. It is understood and agreed that Concentric's use of its proprietary computer software, methodology, procedures, or other proprietary information in connection with an assignment shall not give you any rights with respect to such proprietary computer software, methodology, procedures or other proprietary information. Concentric may retain and further use the technical content of its work hereunder.

9. *Excused Performance* – Concentric shall not be deemed in default of any provision hereof or be liable for any delay, failure in performance, or interruption of service resulting directly or indirectly from acts of God, civil or military authority, civil disturbance, war, strikes or other labor disputes, fires, other catastrophes, or other forces beyond its reasonable control, whether or not such event may be deemed foreseeable.

10. *Related Litigation* – In the event that Concentric employees (current or former), subcontractors or agents are compelled to provide testimony, produce documents, or otherwise incur costs or expend time in any legal proceeding related to Concentric's work for you, you agree to reimburse Concentric at its regular billing rate per hour for its time expended, and for any expenses incurred (at Concentric's direct cost).

11. *Notices* – All notices given under or pursuant to the Terms shall be sent by Certified or Registered Mail, Return Receipt Requested, and shall be deemed to have been delivered when physically delivered if to Concentric Energy Advisors, Inc., 293 Boston Post Road West, Suite 500, Marlborough, MA 01752, Attention Mr. John J. Reed, Chairman and Chief Executive Officer, and if to you at the address shown on the Letter or Proposal of which these Terms are a part or such other address as you may designate by written notice to us.

12. *Complete Agreement* – It is understood and agreed that these Terms and the Letter or Proposal of which they are a part embody the complete understanding of the parties and that any and all provisions, negotiations and representations not included herein are hereby abrogated and that these terms cannot be changed, modified or varied except by written instrument signed by both parties. In the event you issue a purchase order or memorandum or other instrument covering the services herein provided, it is hereby specifically agreed and understood that such purchase order, memorandum, or instrument is for your internal purposes only, and any and all terms and conditions contained therein, whether printed or written, shall be of no force or effect unless agreed to in writing by Concentric. No waiver by either parties of a breach hereof or default hereunder shall be deemed a waiver by such party of a subsequent breach or default of like or similar nature.

13. *Conflicts of Interest* – Concentric confirms it is free of any actual or potential conflicts of interest, respecting this assignment relating to OPG.

14. *Staffing of Assignments* - Concentric shall staff this assignment as described in the attached Contact List for OPG Nuclear EPC (Attachment E). Concentric will be permitted to assign up to three other consulting staff members without Torys' prior approval. Concentric will obtain the prior approval from Torys before assigning any material work to any person beyond those permitted by this paragraph.

    Concentric will strive to avoid duplication of effort in handling the assignment.

15. *Strategy and Budgeting* - At the onset of handling this assignment, Concentric will work with Torys to develop an overall strategy for the assignment. This strategy should be revised periodically as circumstances warrant.

    Concentric acknowledges that it may be asked to prepare a cost estimate or budget to implement the strategy, which has been agreed to for the conduct of an assignment. This budget will be used to assist in evaluating the strategy proposed for the assignment and to assist Torys in monitoring expenses.

16. *Privilege and Confidential Information* - Concentric confirms that correspondence and other communications, memorandums, documents, opinion letters and records exchanged between Torys, OPG business personnel or other OPG representatives and any OPG Counsel are not to be released to other persons without the prior written approval of Torys. It is recognised, however, that the rules of privilege governing the release of such correspondence and other communications, memorandums, documents, opinion letters and records vary from jurisdiction to jurisdiction. Concentric and Torys will agree on a protocol in an effort to to minimise the risk of required disclosure and shall agree as to when Concentric must make any required disclosure. In addition to any requirements imposed on Concentric by law or regulation, Concentric will maintain all information provided to Concentric by Torys and OPG in strict confidence.

17. *Public Disclosure* - Concentric will not publicly disclose or reference work activities performed for Torys and OPG in any manner, including promotional brochures, advertisements, websites or similar representations, without the prior written approval of Torys and OPG.

18. *Accounts* - Notwithstanding the provisions of section 2 above respecting Fees and Expenses, Concentric agrees to the following provisions respecting this assignment.

    Due to the confidential nature of this assignment, Concentric agrees to submit:

    (1) a summary sheet only of each account, showing: (a) the fee, (b) expenses, (c) Canadian goods and services tax or any other applicable taxes, (d) a subtotal, excluding taxes, and (e) the grand total;

    (2) a detailed account which will include at least the following information:

        (a) identification of the billing period to which the account relates;

        (b) an itemised summary of the work that has been undertaken, including a brief description of each service, the date on which each service was rendered, the time spent on each service, the individual who performed the service and the billing rate of such individual;

(c) an itemisation and brief description of all expenses incurred during the billing period, with copies of supporting invoices for any expenses in excess of [redacted], unless Torys indicates that such invoices are not required;

19. *Other Rules on Fees and Expenses*

(a) Concentric will bill for travel expenses only in accordance with OPG's Standard Form Business Expense Schedule provided by Torys to Concentric as the same may be amended, supplemented or replaced from time to time. Concentric may not bill for any time away from the office which is not spent on this assignment.

(b) Concentric will bill for photocopying and printing at a rate of no more than [redacted] per page for all pages on the assignment. If it is anticipated that the photocopying expenses for a particular matter will exceed [redacted] in any month, Concentric will advise Torys accordingly so that it may be considered whether the copying services should be performed by a third party service provider.

(c) Concentric will not bill for telephone expenses or the transmission or receipt of faxes. Whenever possible, e-mail is preferred.

(d) Concentric will not bill for routine (non project specific) secretarial work or office administration, and will not bill for charges for "opening a file", software licenses, system application charges, legal research search fees or office supplies.

(e) Concentric will not bill for overtime of administrative staff, unless Torys has consented to such billings in advance.

(f) Concentric will not bill for time spent preparing or reviewing proposals, accounts or budgets.

20. *General* - These Terms are governed by, and are to be construed and interpreted in accordance with, the laws of Ontario and the laws of Canada applicable in Ontario. These Terms will not be amended by any invoice or other document, even where such document purports to be paramount to any term of these Terms, unless such document is signed by Concentric and Torys.

## AGREED AND ACCEPTED:

______________________________
CLIENT SIGNATURE

TITLE: ______________________________

COMPANY:______________________________

DATE: ______________________________

ATTACHMENT D
RÉSUMÉ OF JOHN J. REED
CONFIDENTIAL

# John J. Reed
## Chairman and Chief Executive Officer

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John J. Reed is a financial and economic consultant with more than 30 years of experience in the energy industry. Mr. Reed has also been the CEO of an NASD member securities firm, and Co-CEO of the nation's largest publicly traded management consulting firm (NYSE: NCI). He has provided advisory services in the areas of mergers and acquisitions, asset divestitures and purchases, strategic planning, project finance, corporate valuation, energy market analysis, rate and regulatory matters and energy contract negotiations to clients across North and Central America. Mr. Reed's comprehensive experience includes the development and implementation of nuclear, fossil, and hydroelectric generation divestiture programs with an aggregate valuation in excess of $20 billion. Mr. Reed has also provided expert testimony on financial and economic matters on more than 150 occasions before the FERC, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. After graduation from the Wharton School of the University of Pennsylvania, Mr. Reed joined Southern California Gas Company, where he worked in the regulatory and financial groups, leaving the firm as Chief Economist in 1981. He served as executive and consultant with Stone & Webster Management Consulting and R.J. Rudden Associates prior to forming REED Consulting Group (RCG) in 1988. RCG was acquired by Navigant Consulting in 1997, where Mr. Reed served as an executive until leaving Navigant to join Concentric as Chairman and Chief Executive Officer.

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## REPRESENTATIVE PROJECT EXPERIENCE

### Executive Management

As an executive-level consultant, worked with CEOs, CFOs, other senior officers, and Boards of Directors of many of North America's top electric and gas utilities, as well as with senior political leaders of the U.S. and Canada on numerous engagements over the past 25 years. Directed merger, acquisition, divestiture, and project development engagements for utilities, pipelines and electric generation companies, repositioned several electric and gas utilities as pure distributors through a series of regulatory, financial, and legislative initiatives, and helped to develop and execute several "roll-up" or market aggregation strategies for companies seeking to achieve substantial scale in energy distribution, generation, transmission, and marketing.

### Financial and Economic Advisory Services

Retained by many of the nation's leading energy companies and financial institutions for services relating to the purchase, sale or development of new enterprises. These projects included major new gas pipeline projects, gas storage projects, several non-utility generation projects, the purchase and sale of project development and gas marketing firms, and utility acquisitions. Specific services provided include the development of corporate expansion plans, review of acquisition candidates, establishment of divestiture standards, due diligence on acquisitions or financing, market entry or expansion studies, competitive assessments, project financing studies, and negotiations relating to these transactions.

### Litigation Support and Expert Testimony

Provided expert testimony on more than 150 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Have been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

Also served on FERC Commissioner Terzic's Task Force on Competition, which conducted an industry-wide investigation into the levels of and means of encouraging competition in U.S. natural gas markets. Represented the interests of the gas distributors (the AGD and UDC) and participated actively in developing and presenting position papers on behalf of the LDC community.

### Resource Procurement, Contracting and Analysis

On behalf of gas distributors, gas pipelines, gas producers, electric utilities, and independent energy project developers, personally managed or participated in the negotiation, drafting, and regulatory support of hundreds of energy contracts, including the largest gas contracts in North America, electric contracts representing billions of dollars, pipeline and storage contracts, and facility leases.

These efforts have resulted in bringing large new energy projects to market across North America, the creation of hundreds of millions of dollars in savings through contract renegotiation, and the regulatory approval of a number of highly contested energy contracts.

### Strategic Planning and Utility Restructuring

Acted as a leading participant in the restructuring of the natural gas and electric utility industries over the past fifteen years, as an adviser to local distribution companies (LDCs), pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to many of the top 50 utilities and energy marketers across North America. Managed projects that frequently included the redevelopment of strategic plans, corporate reorganizations, the development of multi-year regulatory and legislative agendas, merger, acquisition and divestiture strategies, and the development of market entry strategies. Developed and supported merchant function exit strategies, marketing affiliate strategies, and detailed plans for the functional business units of many of North America's leading utilities.

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## PROFESSIONAL HISTORY

**Concentric Energy Advisors, Inc. (2002 – Present)**
Chairman and Chief Executive Officer

**CE Capital Advisors (2004 – Present)**
Chairman, President, and Chief Executive Officer

**Navigant Consulting, Inc. (1997 – 2002)**
President, Navigant Energy Capital (2000 – 2002)
Executive Director (2000 – 2002)
Co-Chief Executive Officer, Vice Chairman (1999 – 2000)
Executive Managing Director (1998 – 1999)
President, REED Consulting Group, Inc. (1997 – 1998)

**REED Consulting Group (1988 – 1997)**
Chairman, President and Chief Executive Officer

**R.J. Rudden Associates, Inc. (1983 – 1988)**
Vice President

**Stone & Webster Management Consultants, Inc. (1981 – 1983)**
Senior Consultant
Consultant

**Southern California Gas Company (1976 – 1981)**
Corporate Economist
Financial Analyst
Treasury Analyst

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## EDUCATION AND CERTIFICATION

B.S., Economics and Finance, Wharton School, University of Pennsylvania, 1976
Licensed Securities Professional: NASD Series 7, 63, and 24 Licenses

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## BOARDS OF DIRECTORS (PAST AND PRESENT)

Concentric Energy Advisors, Inc.
Navigant Consulting, Inc.
Navigant Energy Capital
Nukem, Inc.
New England Gas Association
R. J. Rudden Associates
REED Consulting Group

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## AFFILIATIONS

National Association of Business Economists
International Association of Energy Economists
American Gas Association
New England Gas Association
Society of Gas Lighters
Guild of Gas Managers

# James M. Coyne
## Senior Vice President

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Mr. Coyne provides financial, regulatory, strategic, and litigation support services to clients in the power and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy, capital costs, valuation, fuels, and power markets. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry and provided testimony and expert reports before the Federal Energy Regulatory Commission and jurisdictions in Alberta, British Columbia, California, Connecticut, Massachusetts, New Jersey, Ontario, Maine, Texas, Vermont, and Wisconsin. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New Hampshire.

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## REPRESENTATIVE PROJECT EXPERIENCE

### Expert Testimony and Litigation Experience

- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate rate of return for the Path 15 transmission facilities in California, and the economic and business environment for transmission investments. (FERC Docket ER11-___-000)
- Terasen Utilities: provided a detailed study of alternative automatic adjustment mechanisms for setting the cost of equity, filed with the British Columbia Public Utilities Commission, December, 2010. (In response to BCUC Order No. G-158-09)
- Commonwealth of Massachusetts, Superior Court, Central Water District vs. Burncoat Pond Watershed District; provided expert testimony on the appropriate method for computing interest in an eminent domain taking. (Civil Action No. WDCV2001-01051, May 2010)
- Retained by the Ontario Energy Board to evaluate the existing DSM regulatory framework and guidelines for gas distributors, and based on research on best practices in other jurisdictions, make recommendations and lead a stakeholder conference on proposed changes. (2009-2010)
- ATCO Utilities: primary cost of capital witness on behalf of ATCO Utilities in the 2009 Alberta Generic Cost of Capital proceeding, for the establishment of the return on equity and capital structure for each of Alberta's gas and electric utilities. (AUC Proceeding ID. 85)
- Enbridge: primary cost of capital witness before the Ontario Energy Board in its Consultative Process on the Board' policy for determination of the cost of capital. (EB-2009-0084)
- Provided written comments to the Ontario Energy Board on behalf of Enbridge Gas Distribution, and separately for Hydro One Networks and the Coalition of Large

Distributors in response to the Board's invitation to interested stakeholders to provide comments to help the Board better understand whether current economic and financial market conditions have an impact on the reasonableness of the Cost of Capital parameter values calculated in accordance with the Board's established Cost of Capital methodology; and to help the Board determine if, when, and how to make any appropriate adjustments to those parameter values.

- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, provided expert testimony on the appropriate rate of return, capital structure, and rate incentives for the development and operation of the Path 15 transmission facilities in California. (FERC Docket ER08-374-000)
- Wisconsin Power and Light Company: Before the Public Service Commission of Wisconsin, on establishing ratemaking principles for the company's proposed wind and coal electric generation facility additions, providing expert testimony on the appropriate return on equity. (PSCW Docket Nos. 6680-CE-170 and 6680-CE-171, 2007)
- Aquarion Water Company: Before the Connecticut Department of Public Utility Control, providing expert testimony on establishing the appropriate return on equity for the Company's Connecticut operations. (DPUC Docket No. 07-05-19, 2007)
- Central Maine Power Company: Before the Maine Public Utilities Commission, provided expert testimony on the theoretical and analytical soundness of the Company's sales forecast for ratemaking purposes. (MPUC Docket No. 2007-215, 2007)
- Vermont Gas Systems, Inc.: Before the State of Vermont Public Board, on the company's petition for approval of an alternative regulation plan, provided expert testimony on models of incentive regulation and their relative benefits for VGS and its ratepayers. (VPSB Docket No. 7109, 2006)
- Texas New Mexico Power Company: Before the Public Utility Commission of Texas, on the approval of the company's stranded cost recovery associated with the auction of the company's generating assets. (PUC Docket No. 29206, 2004)
- TransCanada Corporation: Provided an independent expert valuation of a natural gas pipeline, filed with the American Arbitration Association. (AAA Case No. 50T 1810018804, 2004)
- Advised the Board of Directors of El Paso Corporation on settlement matters pertaining to western power and gas markets before FERC. (2003)
- Conectiv: Before the New Jersey Board of Public Utilities, on the approval of the proposed sale of Atlantic City Electric Company's fossil and nuclear generating assets. (NJBPU Docket No. EM00020106, 2000-2001)
- Bangor Hydro Electric Company: Before the Maine Public Utilities Commission, on the approval of the proposed sale of the company's hydroelectric and fossil generation assets. (MPUC Docket No. 98-820, 1998)
- Maine Office of Energy Resources: Before the Maine Public Utilities Commission on behalf of the Maine Office of Energy on the establishment of avoided costs rates for generators under PURPA. (1981-1982)

## Regulatory Support Experience

- For the Canadian Gas Association, facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white paper to facilitate further discussion on emerging industry issues. (2010-2011)
- Retained by Ontario's Coalition of Large Distributors (Enersource Hydro, Horizon Utilities, Hydro Ottawa, PowerStream, Toronto Hydro, and Veridian Connections) to examine the cost of capital for Ontario's electric utilities in relation to those in other provinces and in the U.S. (2008)
- Retained by the Ontario Energy Board to analyze ROE awards for the past two years in Ontario, and compare against other jurisdictions in Canada, the U.S., U.K., and select other European jurisdictions. Differences in awarded ROEs were examined for underlying factors, including ROE methodology, company size, business risks, tax issues, subsidiary vs. parent, and sources of capital. The analysis also addressed the question of whether Canadian utilities compete for capital on the same basis as U.S. utilities. (2007)
- Retained by the Nantucket Planning and Economic Development Commission to educate government officials and island residents on the wind industry, and provide analysis leading to constructive input to the Army Corps of Engineers and the Minerals Management Service on the siting of proposed wind projects. (2004-2007)
- Interim manager of Government and Regulatory affairs for Boston Generating, LLC. Coordinate activities and interventions before FERC, NE-ISO, state regulatory agencies, and local communities hosting Boston Generating power plants. (2004)
- Facilitated the development of an Alternative Regulation Plan with the Department of Public Service and Vermont Gas Systems providing research and advice leading to a rate proposal for the Vermont Public Service Board. Conducted several workshops including the major stakeholders and regulatory agencies to develop solutions satisfying both public policy and utility objectives. (2004-2005)
- For an independent power company, perform market analysis and annual audits of its utility power contract. Services provided include verification of the contract price as a function of its index components, surveys of regional competitive energy suppliers, and analysis of regional spot prices for an independent benchmark. Meet with PUC staff to discuss and represent the company in its annual adjustment process, and report results to the company and its creditors. (2003-2004)

## Financial and Economic Advisory Experience

- Advisor to the New Brunswick Department of Energy on facilitating cross-border experts of energy from the Canadian Maritimes to Northeast U.S. markets. (2008-2011)
- Financial advisor to a major international corporation for investments in U.S. nuclear generating units. (2007-2009)
- Lead regulatory and market due diligence advisor to Macquarie Securities in the $7.4 billion acquisition of Puget Sound Energy. (2007)
- Retained by five Vermont electric utilities to study the comparative economics building the next generation of electric power generation within the state. Working with the utilities, the Vermont Department of Public Service, and the Electric Power Research Institute (EPRI),

ten possible generation technologies were analyzed for their economic and environmental attributes. Costs were compared across technologies, and financial impacts including credit rating were examined. The report was presented in public forums and before state agencies. (2007)

- Advisor to the City of Mesa, Arizona for the potential privatization of the City's electric utility. (2007-2008)
- Independent Market Expert for a large Midwestern utility seeking a credit rating for its electric generation subsidiary. Providing a complete PJM and MISO market assessment and forward financial projections for the company's generation business including over 13,000 MW's of generating capacity. Financial projections are based on LMP price projections for the PJM-MISO interconnect, fuels prices, air emissions prices, and complete financial analysis of the business unit. Also provided support for discussions with the major credit rating agencies in conjunction with an investment bank and independent engineer. (2005-2006)
- Completed financial advisory services to a private equity consortium on the successful acquisition of a gas-fired power generating facility. The engagement included evaluation of all revenue streams, confirmation of investment economics under alternative market scenarios, and support for negotiations on key terms. (2005)
- Engaged by Goldman Sachs to assist with the financial and industry due diligence associated with the acquisition of Zilkha Renewable Energy, a wind energy company with over 20 projects under development. (2005-2006)
- Engaged by the State of Vermont to study of the feasibility of acquiring 550MW of hydroelectric generation facilities from USGen-New England. Completed a valuation of the assets, researched financing options with alternative tax-exempt and taxable structures, monitored the status of NEG's bankruptcy proceedings, researched comparable large-scale municipalizations, studied the potential in-state and out-of-state uses for the power, and tested the market for power sales to regional utilities. Facilitated discussions with companies for equity partnership, as well as for the purposes of providing power marketing and O&M services to the project. In addition to in-house consulting staff, compiled a team of legal, engineering and financing experts to deliver a comprehensive work product reflecting all aspects of the risks and benefits of purchasing this unique set of assets out of bankruptcy. (2003-2004)
- Evaluated a major utility's unregulated energy services business units and advised management on valuation and the potential market for the businesses. Developed offering materials and represented the company in negotiations with a potential buyer. (2001-2002)
- Lead advisor in the auction of Conectiv's $875 million in fossil and nuclear electric generation assets to NRG, PSE&G, and Exelon. Provided expert testimony before the New Jersey Board of Public Utilities on the auction process and asset values. (1999-2002)
- Provided financial and market analysis to Provincial Auditor of Ontario in examination of the long-term lease arrangement for the Bruce nuclear facility between Ontario Hydro and British Energy. (2002)
- For a private equity firm, evaluated on investment in a manufacturer of electric generation equipment. Analyzed the company's sustainable technological advantage, interviewed major

customers, assessed competitor positioning, and provided market and revenue projections for the investment evaluation. (1999)

- Served as technical and market advisor for an investment consortium in the evaluation of an investment in five cogeneration plants. Analyzed fuel and off-take contracts, regulatory risk, plant operating procedures, and management personnel. Provided revenue and cost projections, supported bank discussions, and assisted bid negotiations. (1998)
- Co-advisor to Sithe Energies in the auction of the company's North American assets to Reliant and Exelon, and the marketing of its assets in Australia and Asia. (1999-2000)
- Lead advisor in the electric restructuring, auction of generating assets, and long-term power contracting for Denton Municipal Electric. Conducted regular briefings for the City Council. (1999-2001)
- Co-advisor to Sierra Pacific Resources in the proposed auction of 3,000 MW of fossil generating assets. (1999-2000)
- Co-advisor to TXU in the proposed auction of 560 MW of fossil generating assets. (2000)
- Co-advisor to Boston Edison (NSTAR) in the auction of $536 million in fossil generating assets to Sithe Energy. (1997-1998)
- Co-advisor to GPU in the auction of $1.7 billion in fossil generating assets to Sithe Energy. (1997-1998)
- Lead advisor to Bangor Hydro Electric Company in the auction of $90 million in hydroelectric, transmission, and fossil generating assets to PP&L Global. (1998-1999)

**Business Strategy Experience**

- Retained by a major Canadian electric company to study the cross-border transmission constraints into U.S. power markets and identify strategic options and transmission investments for expanding capacity and energy flows into these markets. (2007)
- Retained by the Western Electric Coordinating Council's (WECC) Board of Directors to facilitate the development of the WECC's five-year strategic plan. WECC is one of eight regional electric reliability organizations in North America, with 180 members across 14 states, and portions of Canada and Mexico. Leading the effort for Concentric, the planning process entails interviewing key stakeholders, facilitating discussion within and across member groups, gathering and presenting research, and making recommendations to the Board on the Strategic Plan. (2007)
- Engaged by a Canadian based utility company to develop its business strategy for growth in the U.S. Working with senior management, providing both a "big picture" strategic assessment of driving forces and opportunities in distribution, transmission and generation, supported by more detailed evaluation of specific investment options for presentation and discussion with its Board. (2005-2007)
- Advisor to Cook Inlet Regional, Inc., an Alaskan Native corporation, for the purpose of developing wind energy projects within the State of Alaska. (2006)
- Advisor to Tamarack Energy, Inc., for the purpose of developing renewable energy projects in the Northeast U.S. (2006)
- Engaged by a major Japanese corporation to provide assistance with the strategic evaluation of its ability to enter the $400 billion power and gas trading market. Management in Tokyo

and New York required an independent assessment of the new and complex U.S. market for power and natural gas, and a determination of the company's ability to successfully compete. (2005-2006)

- Retained by an international power company to assist with evaluation of its corporate strategy and financial performance. Evaluated the company's corporate strategy using modern portfolio management tools to determine the inherent risk/reward trade-offs in the company's business portfolio. Analyzed core drivers of movements in the company's stock price and assisted the management team with engaging the Board of Directors in a strategic evaluation of the company's electric business. (2004)
- Strategic advisor to a major Public Power Authority in its evaluation of alternative business strategies and organizational structure. Provided industry benchmarking and qualitative analysis of various public power models for the Authority and developed future industry scenarios. Collaborated with team of legal and banking advisors in examining restructuring options to maximize benefits to the Authority's stakeholders. (2004-2005)
- Provided analysis for the FirstEnergy Board of Directors regarding the potential economic impact of the 2003 power outage. (2003)
- Provided a strategic assessment of an eastern utility's electric generation and marketing business. The strategic assessment included: analysis of wholesale and retail electric markets in PJM, NE and NY markets, capacity, energy and ancillary service products, transmission and congestion, customers for wholesale products, competitors, short-term and long-term financial measures of viability, and factors for success. The engagement involved brainstorming sessions with the client team, research and analysis, and concluded with a report and evaluation of the company's strategic options and business prospects. (2003)
- Developed a cost of capital and investment decision-making framework for the company's new business investments. (2002)
- Strategic advisor to a Mid-Atlantic Utility in the development and implementation of the company's generation and marketing business. (1999-2000)

## PUBLICATIONS AND RESEARCH

- "Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010
- "A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June, 2007
- "Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006
- Utility Strategy and Shareholder Return (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004
- "Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003

- "The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001
- Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992
- "Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

## SELECTED SPEAKING ENGAGEMENTS

- "M&A and Valuations," Panelist at Infocast Utility Scale Solar Summit, September 2010
- "The Use of Expert Evidence," The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010
- "A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008
- "Nuclear Power on the Verge of a New Era," moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005
- "The Investment Implications of the Repeal of PUCHA," Skadden Arps Client Conference, New York, NY, October 2005
- "Anatomy of the Deal," First Annual Energy Transactions Conference, Newport, RI, May 2005
- "The Outlook for Wind Power," Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005
- "Direction of U.S. M&A Activity for Utilities," Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002
- "Outlook for U.S. Merger & Acquisition Activity," Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001
- "Investor Perspectives on Emerging Energy Companies," Panel Moderator at Energy Venture Conference, Boston, MA, June 2001
- "Electric Generation Asset Transactions: A Practical Guide," workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999
- "New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999
- "Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998
- "Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998
- "New Market Dynamics," New England-Canada Business Council Annual Meeting, November 1996

- "Fuels Markets and Generation Choices," Electric Power Research Institute Seminar, Charleston, SC, October 1989
- "Issues Underlying the Long-Term Outlook for Natural Gas Markets," International Association for Energy Economics' International Conference, Calgary, Canada, July 1987

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## PROFESSIONAL HISTORY

**Concentric Energy Advisors, Inc. (2006 – Present)**
Senior Vice President
Vice President

**FTI Consulting (Lexecon) (2002 – 2006)**
Senior Managing Director – Energy Practice

**Arthur Andersen LLP (2000 – 2002)**
Managing Director, Andersen Corporate Finance – Energy and Utilities

**Navigant Consulting, Inc. (1996 – 2000)**
Managing Director, Financial Services Practice
Senior Vice President, Strategy Practice

**TotalFinaElf (1990 – 1996)**
Manager, Corporate Planning and Development
Manager, Investor Relations
Manager of Strategic Planning and Vice President, Natural Gas Division

**Arthur D. Little, Inc. (1989 – 1990)**
Senior Consultant – International Energy Practice

**DRI/McGraw-Hill (1984 – 1989)**
Director, North American Natural Gas Consulting
Senior Economist, U.S. Electricity Service

**Massachusetts Energy Facilities Siting Council (1982 – 1984)**
Senior Economist – Gas and Electric Utilities

**Maine Office of Energy Resources (1981 – 1982)**
State Energy Economist

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## EDUCATION

M.S., Resource Economics, University of New Hampshire, with Honors, 1981

B.S., Business Administration and Economics, Georgetown University, Cum Laude, 1975

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## DESIGNATIONS AND AFFILIATIONS

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001
NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984
American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996
National Petroleum Council, Regulatory and Policy Task Forces, 1992
President, International Association for Energy Economics, Dallas Chapter, 1995
Gas Research Institute, Economics Advisory Committee, 1990-1993
Georgetown University, Alumni Admissions Interviewer, 1988 - current

ATTACHMENT D
RÉSUMÉ OF SAMUEL G. EATON
CONFIDENTIAL

# Samuel G. Eaton
## Project Manager

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Mr. Eaton joined Concentric in 2005. His background includes financial analysis and project support. He has engaged in rate design for both natural gas and electric utilities, reviewed the various billing policies of ISO-NE, analyzed pipeline capacity needs for a local distribution company, analyzed market demand for local distribution and pipeline companies and facilitated the development of expert reports ranging in topics from round-trip trades to spent nuclear fuel. In addition, Mr. Eaton has participated in several facets of nuclear and fossil-fueled divestitures, information memorandum development, due diligence, workforce matters, document collection, and the development and negotiation of purchase and sale agreements. Prior to joining Concentric, Mr. Eaton created the Empowerment Zone Database for the Jacksonville Economic Development Commission (JEDC), while providing project support for several local development projects. In addition, he aided the JEDC with their recent reorganization.

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## REPRESENTATIVE PROJECT EXPERIENCE

### Regulatory Support

*New Nuclear Cost Recovery*
Currently serving as the day-to-day project manager for Concentric's work related to FPL's nuclear expansion programs. This work includes the review and audit of FPL's internal control environment and supporting Concentric's expert witness in developing testimony before the Florida Public Service Commission. This work also involves the appropriate implementation of the Prudent Investment Standard

*Resource Planning*
Provided analysis for a investor owned utility to determine the prudence of the company's capacity acquisitions. Researched and analyzed the methods used by other companies to determine design day criteria when acquiring new natural gas supply resources. Assisted a western investor owned utility with the evaluation of responses to a request for proposal for new generating capacity.

*Return on Equity*
Assisted Concentric's expert witnesses in the preparation of numerous written testimonies which opined on the appropriate return on equity for several investor owned utilities. This testimony was filed before numerous state utility regulatory commissions and the Federal Energy Regulatory Commission. This work included analyzing discounted cash flow, multiple regression and Capital Asset Pricing model analysis.

*Rate Design*
Researched the history of multiple rates cases for a major Western natural gas and electric utility. Participated in the responses to state regulators regarding a major utility's rate case filings. Aided in the development of multiple returns on equity expert testimonies and supported them with quantitative and comparative financial analysis. Participated in the document collection efforts for a large New England utility's marginal cost of service filing.

**Litigation Support**

*Spent Nuclear Fuel Cases*
Assisted the preparation of an expert report which opinioned on the likely impact of the government's partial breach of the Standard Contract on the sales prices of a number of nuclear power plants. This work included researching the contemporaneous opinions of power plant investors, reviewing and analyzing thousands of documents produced during discovery, participating in opposing witness depositions, quantifying the impact of the government's partial breach with a discounted cash flow model and preparing Concentric's expert witness for depositions and trial.

*Theft of Trade Secrets*
Produced an expert report on behalf of Concentric's expert witness that reviewed the state of IPP market in the 2002-2005 time periods and the rebutted the plaintiff's damages claim that the alleged theft of trade secrets resulted tens of millions of dollars of damages. This work included reviewing the plaintiff's damages claims, reviewing numerous depositions, producing a discounted cash flow analysis, researching the financial strength of large independent power producers during the time period and producing the expert report.

*Bankruptcy*
Currently producing an expert report opining on the likely going concern valuation of a bankrupt IPP and the adequacy of the capitalization of the IPP at certain points in history. This work includes developing discounted cash flow models, reviewing certain credit agreements related to the facility, reviewing and analyzing comparable transactions and producing a replacement costs analysis.

**Financial Advisory**

*Transaction Experience*
Participated in the buy side due diligence of a major private equity investor reviewing the potential acquisition of over 1.5 GW of capacity. Facilitated the due diligence efforts of multiple bidders, the development of the purchase and sale agreement, document collection process, and overall auction management in Atlantic City Electric's sale of a minority interest in the Keystone and Conemaugh coal- and oil- fired Generating Stations. Managed the due diligence efforts, document collection process, auction schedule, participated in the development and negotiation of a purchase and sale agreement and a comparative valuation model in Atlantic City Electric's sale of the coal- and oil-fired B.L. England Generating Station. Participated in the regulatory approval process for the sale of IPL's 70% interest in the Duane Arnold Energy Center. Developed an information memorandum and terms of sale, while helping to manage bidder due diligence during the sale of Palisades Nuclear Plant. Developed an information memorandum, coordinated the document collection and assisted the due diligence efforts of multiple bidders in the sale of We Energies' Point Beach Nuclear Plant. Participated in the due diligence efforts of multiple bidders during the sale of the MASSPOWER gas-fired combined cycle generating facility.

*Fairness Opinions*
Assisted Concentric with the preparation of numerous fairness opinions related to the sale or purchase of natural gas power plants, coal fired power plants, natural gas LDCs and retail electric companies. This work has included the preparation of discounted cash flow models, analyzing comparable transactions and producing replacement costs analysis.

*Debt Financing*

Developed an offering memorandum and coordinated marketing efforts for a $100 million refinancing of a small independent power producer. Assisted the client with their evaluation of and negotiations with lenders before selecting a preferred lender with which the Company closed a senior debt facility

**Market Analysis**

*Pipeline Demand Analysis*
Performed market research to determine economic feasibility of new client acquisition for a Northeastern gas company. Analyzed fuel switching capabilities of potential new customers. Conducted research in support of nuclear transaction-related efforts. Performed market demand analysis for a Northeastern pipeline company. Reviewed the workforce implications resulting from the possible sale of a Midwestern nuclear facility.

*ISO-NE Billing Analysis*
Conducted extensive research into the billing polices of ISO-NE for a Northeastern company. This work culminated in a detailed review and audit of that companies invoices from ISO-NE.

*ISO-NE Forward Capacity Market*
Participated in Concentric's role as the market monitor for ISO-NE's Forward Capacity Market. This work included producing real levelized cost models to determine the reasonableness of market participants' bids into this market.

## PROFESSIONAL HISTORY

**Concentric Energy Advisors, Inc. (2005 – Present)**
Project Manager
Senior Consultant
Consultant
Assistant Consultant
Analyst

**Jacksonville Economic Development Commission (2004)**
Internship - Database Management & Project Support

## EDUCATION

B.A., Economics, Business minor, Brandeis University, cum laude, 2005

# Daniel S. Dane, CPA
## Senior Project Manager

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Daniel S. Dane is a consultant with 10 years of experience in the energy and financial services industries. Mr. Dane has provided advisory services in the areas of litigation support, generating asset divestitures, utility regulation and ratemaking, valuation, financial statement audits and analysis, and the examination of financial reporting systems and controls. He has also provided expert testimony on regulated ratemaking matters for an investor-owned utility. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is a certified public accountant, and is a licensed securities professional (Series 7, 28, 63, and 79). Mr. Dane also serves as the Financial and Operations Principal of CE Capital Advisors, a FINRA-Member firm and a subsidiary of Concentric.

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## REPRESENTATIVE PROJECT EXPERIENCE

### Litigation Advisory Assignments

Prepared analyses and reports in a variety of proceedings related to energy, economic, and litigation issues. Clients in these matters have included international diversified energy companies and electric distribution companies. Representative engagements have included:

- For a diversified energy company involved in litigation related to the lease-leaseback of a gas-fired combined heat and power plant, performed appraisal review services, created an economic model to test the sensitivity of the plant's valuation model to changes in economic drivers, and supported the development of expert testimony.
- Spent nuclear fuel litigation. For three utilities involved in litigation with the U.S. Department of Energy regarding breach of contract for the removal of spent nuclear fuel from nuclear reactor sites, performed pro-forma valuations of generating facilities to quantify diminished sale value due to breach and supported the development of written testimony regarding the analyses.

### Financial Advisory Assignments

As part of electric generating and transmission asset divestitures, responsibilities have included marketing, due diligence support, drafting of transaction agreements, bid evaluation, and closing/regulatory approval assistance. Transactions included nuclear, coal, gas-fired, and hydroelectric generating assets. Performed independent valuations, appraisals, and market analyses in support of asset and equity acquisitions and divestitures. Performed financial statement audits for public and private companies. Performed attestation services for a global public company as part of the implementation of Sarbanes-Oxley Section 404 regulations.

Representative engagements have included:

- Transaction team member for the following asset divestitures:
    - Wisconsin Electric's $998 million sale of the 1,036 MW Point Beach Nuclear Power Plant
    - Consumers Energy's $380 million sale of the 798 MW Palisades Nuclear Power Plant
    - Interstate Power & Light's $373 million sale of the 583 MW Duane Arnold Energy Center
    - Atlantic City Electric's $173 million sale of its ownership interest in the 1,712 MW Keystone and Conemaugh coal-fired stations

  - The equity holders' sale of the MASSPOWER station, a 258 MW gas-fired facility
- Participated in or managed the development of fairness opinions issued by CE Capital Advisors, Inc. to Boards of Directors of companies entering into asset purchases and sales.
- Provided buy-side support to an international developer of wind generation targeting investment in U.S. wind properties. Engagement included valuing wind assets in various stages of development and evaluating multiple ownership/tax-equity structures.
- For a desalination plant developer, appraised desalination facilities in California for corporate accounting purposes. Appraisal included providing a going concern valuation and opinion.
- For a hedge fund, performed a valuation of a generating company to provide support for investment decision making.
- For the developer of a multi-billion dollar Greenfield natural gas pipeline, provided research and advice related to accounting treatment of construction and financing costs, and developed a cost of service and revenue requirements model for use in the open season process.
- For an international diversified company investing in a Texas pipeline and natural gas marketer, performed accounting-related due diligence, developed an opening balance sheet in accordance with U.S. GAAP, and performed subsequent tests for impairment of Goodwill and intangible assets.
- For a confidential Transmission & Distribution ("T&D") company, developed an application for Department of Energy loan guarantees pursuant to the American Recovery and Reinvestment Act of 2009.

**Ratemaking and Utility Regulation Assignments**

Performed financial and other analyses and drafted expert testimony and reports related to multiple regulatory proceedings. Representative engagements have included:

- Submitted expert direct and rebuttal testimony on behalf of Ameren's Illinois utilities regarding ratemaking policy issues specifically related to regulated rate base (Illinois Commerce Commission Docket No. 09-0306 through 09-0311 (Cons.)).
- For utilities developing decoupling proposals, developed financial models to back-cast and forecast the effects of various types of decoupling mechanisms, capital expenditure tracking mechanisms, and inflation tracking mechanisms.
- Supported expert testimony related to corporate cost allocations on behalf of Constellation Energy Group as part of the Maryland Public Service Commission's 2009 review of the merger between Constellation Energy Nuclear Group and E.D.F. International SA.
- Preparation of multiple rounds of testimony in support of a group of utilities, including Oncor Electric Delivery Company, AEP and MidAmerican Energy, seeking to construct over $5 billion of new transmission in Texas as part of the state's Competitive Renewable Energy Zone process.
- For Oncor Electric Delivery Company's 2008 rate case, supported the development of written direct and rebuttal testimony and analyses regarding the return of and on capital, as well as the effects of recent merger activity, the 2008/2009 credit crisis, and changing business and operating environments thereon.
- For NSTAR, on two separate occasions reviewed the company's cost of service calculations to determine and certify to the Massachusetts Attorney General that the calculations were performed in accordance with NSTAR's tariff.
- For the Ontario Energy Board ("OEB"), performed a comparison of authorized equity returns for natural gas utilities in Canada and the U.S., including an analysis of cross-border differences in access to capital and the effect of firm size on required returns on equity. Presented findings to the OEB and the Ontario Energy Association ("OEA") at the 2007 OEA ROE Seminar.

- Supported development of Cost of Capital Expert Testimony for the electric, gas LDC, pipeline, and steam utilities.

**Management and Operations Consulting Assignments**

Representative engagements have included:

- For the owners of the Palo Verde Nuclear Generating Station, performed a comprehensive study of the costs being incurred by Arizona Public Service to support operations of the plant, including a benchmarking study.
- For We Energies, performed a synergies analysis to quantify benefits of a recent merger.

**Research Assignments**

Reviewed and summarized accounting guidance and tax law to assist clients in interpreting and applying U.S. GAAP and provisions of the Internal Revenue Code.

## PRESENTATIONS

"A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Jim Coyne and Julie Lieberman), presented to the Ontario Energy Association, June, 2007.

## PROFESSIONAL HISTORY

**Concentric Energy Advisors, Inc. (2004 – Present)**
**CE Capital Advisors, Inc.**
Project Manager (Concentric)/Financial and Operations Principal (CE Capital)
Senior Consultant
Consultant

**Ernst & Young (2000 – 2001, 2003 – 2004)**
Staff Auditor
Database Management Associate

**ZIA Information Analysis Group (1997 – 2000)**
Senior Consultant
Consultant

## EDUCATION AND CERTIFICATIONS

M.B.A., Boston College, 2003
B.A., Economics, Colgate University, 1996
Licensed Securities Professional: NASD Series 7, 28, 63, and 79 Licenses

## DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Public Accountant, 2004

Massachusetts Society of Certified Public Accountants, 2004

# Stephen H. Caldwell
## Senior Consultant

Mr. Caldwell has more than seven years of experience conducting policy analysis and providing strategy, general management, and regulatory consulting services. His experience includes merger and acquisition advisory services, due diligence, energy and economic modeling, energy technology evaluation, energy and environmental policy analysis and development, and coordination of multi-sector stakeholder-driven initiatives. Prior to joining Concentric, Mr. Caldwell served as a Senior Fellow at the Pew Center on Global Climate Change, a leading energy and environmental policy think tank.

## REPRESENTATIVE PROJECT EXPERIENCE

### Financial and Economic Advisory Services

Conducted due diligence related to financial guarantee extended to a renewable energy project developer. Provided comparable company and transaction value analysis to client seeking to acquire a natural gas distribution company as well as a review of competitors and regulatory issues.

### Clean Energy Technology Assessment

Engaged in research related to clean energy technologies (including renewables, energy efficiency, nuclear power, and carbon capture and storage) anticipated to play a substantial role in improving the environmental profile of electricity generation. Evaluated the current status and potential of such technologies. Identified technical, policy, and market impediments to widespread deployment of clean energy technologies and recommended policies to address such challenges.

### Public Policy Analysis

Tracked, analyzed, and formulated energy and environmental policies at the state, regional, and federal levels—including electricity portfolio standards, energy efficiency policies, greenhouse gas cap and trade, and criteria and toxic air pollutant regulations. Worked with stakeholders from industry, academia, civil society, and government to analyze and formulate policies. Assessed the implications of various policy design choices for energy producers and consumers. Managed sophisticated energy and economic modeling analyses of climate and energy policy proposals.

### Business Strategy and Operations

Identified and screened new product and service offerings and acquisition targets. Supported supply chain cost saving initiatives. Recommended organizational and general management changes to improve operating performance.

## PROFESSIONAL

**Concentric Energy Advisors, Inc. (2011 – present)**
Senior Consultant

**Pew Center on Global Climate Change (2008 - 2011)**
Senior Fellow
Technology and Policy Fellow
Regional Policy Coordinator

**Synapse Energy Economics (2007)**
Summer Associate

**Massachusetts Institute of Technology, Sloan School of Management (2004-2005)**
Senior Research Associate

**Kerdan Group (2003-2004)**
Senior Consultant

**Tigris (now Bravo Solutions) (2000-2003)**
Senior Consultant
Consultant

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## EDUCATION

M.P.P., Georgetown University, 2008
B.A., Harvard University, 2000

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## PUBLICATIONS/PRESENTATIONS

- "Electricity Demand in a Low-Carbon Energy Future," IEEE Power and Energy Society 2010 General Meeting Plenary Session
- "Climate Change, Public Opinion, and Utility Rates," National Association of Regulatory Utility Commissioners (NARUC) 2008 Summer Committee Meetings

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## AVAILABLE UPON REQUEST

Extensive client and project listings, and specific references.

# Mark C. Cattrell
## Senior Consultant

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Mr. Cattrell has provided financial analysis, regulatory advisory services, and public policy analysis on a variety of engagements with Concentric. His projects have included strategic assessments of the U.S. nuclear energy industry, asset valuations, state regulatory and federal litigation cases, nuclear regulatory matters, expert testimony preparation, and client initiated studies on a wide range of energy-related issues.

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## REPRESENTATIVE PROJECT EXPERIENCE

### Financial and Economic Advisory Services

Performed asset valuations and financial modeling associated with spent nuclear fuel litigation. Assessed value of a hydroelectric generating facility for a major US utility by developing a discounted cash flow model. Verified economic assumptions used in appraisal of a proposed desalination facility for a multinational industrial developer. Provided research on comparable transactions, previous mergers and acquisitions, and potential transaction opportunities.

### Regulatory Analysis and Ratemaking

Conducted regulatory analysis and economic research for electric and natural gas utilities to support expert testimony in ratemaking proceedings before state regulatory agencies. Conducted research to support testimony associated with the natural gas revenue decoupling. Evaluated economic potential of baseload energy alternatives for leading US renewable energy supplier to support regulatory filings for multi-billion dollar nuclear expansion. Performed a competitive analysis of nuclear performance as part of a benchmarking study. Customized a model to design support rate design recommendations based on cost of service studies.

### Energy Market Assessment

Conducted an assessment of the United States nuclear power industry for a European client, including assessment of proposed expansions to present fleet of nuclear generating plants. Created demographic and economic projections to support valuation studies. Evaluated process by which a major western utility conducted long-range resource planning.

### Business Strategy and Operations

Performed strategic and competitive analysis of proposed nuclear construction projects. Composed and compiled sections of a major financing application to the Department of Energy. Conducted a study of local statutes, tax policies, and incentives for infrastructure projects.

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## PROFESSIONAL

**Concentric Energy Advisors, Inc. (2008 – present)**
Senior Consultant
Consultant

**Harvard University (2003 - 2006)**
Associate

**Janus Associates, Inc. (2001 – 2002)**
Jr. Consultant

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## EDUCATION

M.P.P., Georgetown University, 2008
B.A., Colby College, 2001

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## DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Energy Bar Association
National Association of Business Economics
U.S. Association of Energy Economics

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## AVAILABLE UPON REQUEST

Extensive client and project listings, and specific references.

ATTACHMENT D
RÉSUMÉ OF JAMES H. KAHLER
CONFIDENTIAL

# James H. Kahler
## Consultant

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Mr. Kahler joined Concentric in 2007. He has contributed to projects involving litigation support, rate design, regulatory support and strategy, and market assessment. Mr. Kahler also has extensive experience in strategic and policy analysis and database development. His work at Concentric has involved researching regulatory affairs, demand forecasting, transactional due diligence, and contributing to reports and testimony. Prior to joining Concentric, Mr. Kahler researched Middle East economic and security issues at an academic think-tank and an independent risk and security consultancy. He is an active member of the Energy Bar Association and the U.S. Association of Energy Economists.

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## REPRESENTATIVE PROJECT EXPERIENCE

### Litigation Support

- Aided in the development of expert report supporting a damage claimed incurred by a former nuclear asset owner during a previous asset divestiture by reviewing over 60,000 case-related documents and summarizing findings

### Market Analysis

Market research activities that Mr. Kahler has been involved with include:

- Supporting market demand assessment for a West Coast utility
- Analyzing transmission investment and regulatory trends in the western U.S.
- Developing preliminary due diligence reports on energy companies, including: analyzing relevant financial statements and asset portfolios and reviewing market area growth opportunities and potential market risks

### Rate Design

Mr. Kahler has worked on projects related to utility rate design issues. Specifically, he has:

- Analyzed allocation methodology for a shared services company
- Researched report on revenue decoupling mechanisms and trends
- Supported lead-lag analysis and testimony
- Conducted research on performance-based ratemaking and applicable precedents.
- Participated in the responses to state regulators regarding a major utility's rate case filings
- Aided in the development of multiple returns on equity expert testimonies and supported them with quantitative and comparative financial analysis.
- Participated in the document collection efforts for a large Midwestern utility's marginal cost of service filing.

### Transaction Experience

- Buy-side valuation and assessment of generation assets in Midwestern US
- Buy-side due diligence of a diversified utility in the Pacific Northwest

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## PROFESSIONAL HISTORY

**Concentric Energy Advisors, Inc. (2007 – Present)**
Consultant
Assistant Consultant
Analyst
Associate

**Crown Center for Middle East Studies (2006 – 2007)**
Research Assistant

**The Akribis Group, Center for Terrorism and Intelligence Studies (2007)**
Researcher

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## EDUCATION

B.A. with High Honors, Brandeis University, 2007

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## DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Energy Bar Association
U.S. Association of Energy Economics

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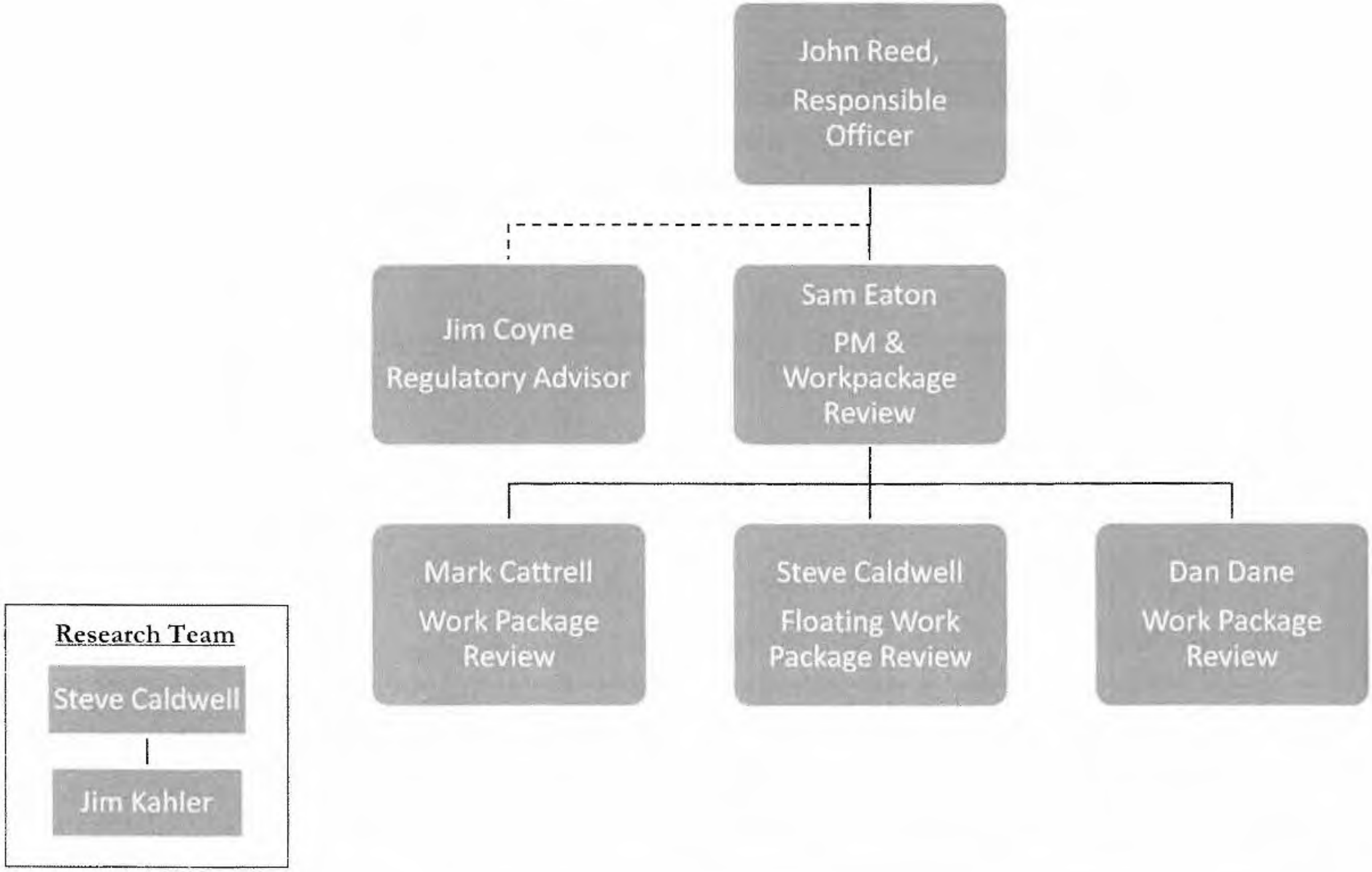
ATTACHMENT E
CONFIDENTIAL

# CONTACT LIST FOR OPG NUCLEAR EPC

| CONCENTRIC ENERGY ADVISORS | 293 BOSTON POST ROAD, SUITE 500<br>MARLBOROUGH, MA 01752<br>1130 CONNECTICUT AVE NW, SUITE 850<br>WASHINGTON, DC 20036 | |
|---|---|---|
| **Name/Title** | **Phone/Fax** | **Email** |
| John J. Reed<br>Chairman, CEO<br>(Responsible Officer) | Phone: 508-263-6262<br>202-587-4477<br>Cell: 617-699-8136<br>Fax: 508-303-3290 | jreed@ceadvisors.com |
| Jim Coyne<br>Senior Vice President<br>(Regulatory Advisor) | Phone: 508-263-6255<br>Cell: 617- 620-1524<br>Fax: 508-303-3290 | jcoyne@ceadvisors.com |
| Sam Eaton – main contact<br>Project Manager<br>(Project Manager/Work Package Review) | Phone: 508-263-6233<br>Cell: 617-970-2383<br>Fax: 508-303-3290 | seaton@ceadvisors.com |
| Dan Dane<br>Senior Project Manager<br>(Work Package Review) | Phone: 508-263-6208<br>Cell: 617-515-3739<br>Fax: 508-303-3290 | ddane@ceadvisors.com |
| Mark Cattrell<br>Senior Consultant<br>(Work Package Review) | Phone: 202-587-4783<br>Cell: 617-283-7976<br>Fax: 202-587-4479 | mcattrell@ceadvisors.com |
| Steve Caldwell<br>Senior Consultant<br>(Work Package Review/Research) | Phone: 508-263-6206<br>Cell: 413-548-4044<br>Fax: 508-303-3290 | scaldwell@ceadvisors.com |
| Jim Kahler<br>Consultant<br>(Research) | Phone: 202-587-4779<br>Cell: 202-384-2340<br>Fax: 202-587-4479 | jkahler@ceadvisors.com |
| Joanna Bickford<br>Executive Assistant<br>(Project Assistant) | Phone: 508-263-6227<br>Cell: 508-320-6572<br>Fax: 508-303-3290 | jbickford@ceadvisors.com |
| Amanda Alford<br>Project Assistant<br>(Backup Project Assistant) | Phone: 508-263-6272<br>Cell:<br>Fax: 508-303-3290 | aalford@ceadvisors.com |

# OPG NUCLEAR EPC – PROJECT 02767
# TEAM ORGANIZATIONAL CHART



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Attachment 8-1

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| **ONTARIO POWER GENERATION** | **Document Number :**<br>N-BCS-00120.3-10007 | **Revision :**<br>1.0 | **Page:**<br>1 of 29 |
| | **DRC at the Clarington Energy Centre**<br>**Full Release Business Case Summary**<br>**OPG CONFIDENTIAL** | | |

| **ROUTING** | **LOCATION** | **ACTION** | **SIGNATURE** | **DATE** |
|---|---|---|---|---|
| **PROJECT MANAGER** | | | | |
| Don Seedman<br>(Project Manager)<br>Manager, Facilities & Projects<br>Real Estate & Services | H18-H11 | Review BCS | | Dec 06/10 |
| Glenn Temple<br>VP, Real Estate & Services | H18-J11 | Review BCS | | Dec 7/10 |
| **PROJECT SPONSOR** | | | | |
| Gary Rose<br>Director, Planning & Control<br>Nuclear Refurbishment | O11 | Review BCS | | Dec. 9/10 |
| Mark Arnone<br>VP, Refurbishment Execution<br>Nuclear Refurbishment | O11 | Review BCS | | 9 Dec 2010 |
| Dietmar Reiner<br>SVP, Nuclear Refurbishment | O11 | Submit BCS | | Dec 9, 2010 |
| Bill Robinson<br>EVP, Nuclear Refurbishment<br>Projects & Support | P82-2 | Recommend BCS | | Dec 10, 2010 |
| **FINANCE REVIEW** | | | | |
| Jamie Lawrie<br>Director<br>Nuclear Investment | P82 | Review BCS | | Dec 9/2010 |
| Randy Leavitt<br>Vice President,<br>Nuclear Finance | P82 | Review BCS | RLeavitt | Dec 10, 2010 |
| Don Power<br>Vice President,<br>Corporate Investment<br>Planning | H07-G05 | Review BCS | D Power | Dec 7/10 |
| **BCS APPROVAL** | | | | |
| Donn Hanbidge<br>SVP & Chief Financial Officer | H19-F27 | Approve BCS | | Dec 31/10 |
| Tom Mitchell<br>President & Chief Executive<br>Officer | H19-A24 | Approve BCS | | 28 Dec 2010 |
| **FOR DISTRIBUTION** | | | | |
| Magued Ernest<br>Refurb Planning & Controls<br>703-5428 | O11 | Return for<br>Distribution<br>& Filing | M Ernest | Jan 03/11 |

## DARLINGTON REFURBISHMENT COMPLEX AT THE CLARINGTON ENERGY CENTRE
## PROJECT ID 10-73803

## PHASE 3: DESIGN, CONSTRUCT AND COMMISSION THE DARLINGTON REFURBISHMENT COMPLEX

## 1. RECOMMENDATION:

Approval is requested for a full release of $85.7M ($84.0M Capital and $1.7M OM&A) for a total release value of $105.4M including contingency to carry out design and construction of the OPG Darlington Refurbishment Complex ("DRC") at the Clarington Energy Centre ("CEC"), in support of the Darlington Refurbishment Program. Funding is specifically requested in order to:

- Complete negotiations and award a Design-Build contract,
- Manage the Design-Build contract during the design and construction period,
- Commission the completed building and furnish the office areas to OPG standards, and
- Provide owner's oversight, project controls, and reporting on the progress of the Project.

The following table summarizes releases to date and the full release project estimate.

| $000's | Funding | LTD 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|
| Currently Released | Partial | 7,248 | 7,098 | 4,480 | 860 | | | | **19,686** |
| Requested Now | Full | (5,157) | 24,593 | 40,795 | 25,444 | | | | **85,676** |
| Future Funding Req'd | Full | - | - | - | - | - | | | **-** |
| Total Project Costs | | 2,091 | 31,691 | 45,275 | 26,304 | - | - | - | 105,362 |
| Ongoing Costs | ~6M/year | - | - | - | 2,820 | 5,752 | 5,867 | | **14,439** |
| Grand Total | | 2,091 | 31,691 | 45,275 | 29,124 | 5,752 | 5,867 | - | 119,801 |
| **Investment Type**<br>**Strategic** | | **Class**<br>**Cap & OM&A** | | **NPV or IEV**<br>**-96,556** | | **IRR**<br>**N/A** | | **Discounted Payback**<br>**N/A** | |

A request for proposals (RFP) was issued on September 24, 2010 to 5 proponents. The RFP included the statement of needs for the facility. The RFP closed on November 17, 2010. Evaluation of the proposals is underway. OPG will select a proponent or proponents to negotiate with, and finalize a contract by March 2011. The project estimate included in this BCS is based on OPG's review of pricing as provided in the RFP responses. Award is planned to be complete by mid March 2011 in order to maintain the overall project schedule and to start construction by July 2011.

### Expected Business Results

The expected business results are:

- Design, construction and commissioning of a multi-purpose complex, referred to as the Darlington Refurbishment Complex ("DRC") which will support project readiness for the Darlington Refurbishment Program. This complex will provide the long-term facility for specialized maintenance and other Darlington support functions upon completion of the Darlington Refurbishment program.

The expected benefits of the DRC include:

- A multi-purpose building to meet the needs and timeline of the Darlington Refurbishment Program, including an area available for usage for a mock-up and testing facility for fuel channel and feeder replacement ("R&FR") work in preparation for refurbishment outage execution, a warehouse, a new Information Centre, training and security in-processing centres, and as a project management team office for the Refurbishment Program.

- Upon completion of the refurbishment project, the DRC will allow the consolidation of leases and co-location of support staff, including Inspection and Maintenance (IMS), closer to the Darlington site.

This project is categorized as a Strategic investment due to its requirement to be in place to meet the timeline of the Darlington Refurbishment Program. The in-service date of mid 2013 for this facility will provide sufficient time for the reactor mock-up tool testing and training in order to meet the timeline for the early start date of the first unit refurbishment in October 2015.

The reactor mock-ups are excluded from the scope of the DRC. The reactor mock-ups project will include the design, supply and installation of the reactor mock-ups, and any required changes to the DRC including electrical trenching to house and support the mock-ups.

Funding for this project is listed in the approved Nuclear Refurbishment Business Plan and included as part of the Darlington Refurbishment Preliminary Planning Release #3 as approved by OPG's Board of Directors on November 19, 2009. The current estimate exceeds the estimate in that Release by $14.9M.

In March 2010, a total release of $19.7M was approved for Phase 1, Land Development and Phase 2, Site Servicing and Contract Tendering of this project. OPG executed subdivision and servicing agreements with the Municipality of Clarington and Durham Region. The tendering process for installation of services is scheduled to be initiated in December 2010. Site servicing installation is planned to commence in February 2011 with completion of necessary infrastructure to the DRC by June 30, 2011 to allow construction to commence in July, 2011. Specifications for the DRC were finalized; an RFP was issued and closed and evaluation of the proposals is currently underway.

The purpose of this Business Case Summary is to obtain Senior Management and Board concurrence to access previously approved funds under Release #3, to award a contract in Q1 2011, and to design, construct, and commission the Darlington Refurbishment Complex Project.

## 2. SIGNATURES

**Submitted by:**

Dec 9, 2010
Dietmar Reiner Date
SVP - Nuclear Refurbishment

**Recommended by:**

DEC 10, 2010
Bill Robinson Date
EVP - Nuclear Refurbishment,
Projects, and Support

**Finance Approval by:**

Dec 13, 2010
Donn Hanbidge Date
SVP & Chief Financial Officer

**Executive Approval by:**

Dec 13, 2010
Tom Mitchell Date
President & CEO

## 3. BACKGROUND & ISSUES

Based on an identified need for additional facilities in the Clarington area, Real Estate Services contracted a national real estate brokerage firm to pursue land acquisition opportunities. A conditional Agreement of Purchase and Sale was signed in March 2007 to purchase a 61 acre property on Osborne Road, west of the Darlington Site. Due diligence activities were completed in June 2007, and the purchase closed in July 2007. The Draft Plan of Subdivision was approved by the Municipality of Clarington on March 24, 2009, and the Subdivision Agreement was executed on July 27, 2010.

The Darlington Refurbishment project, through a Retube and Feeder Replacement ("R&FR") this study, and as documented in NK38-REP-09701-10001, identified the need for a training, mock-up and testing facility within 20 km of the station. The facility will include an extensive reactor mock-up, training, and warehousing facilities to support full R&FR tool set integration testing, for procedure development and crew training. Based on operating experience from other refurbishments, the R&FR study recommended that the training and mock-up facility be available by the fall of 2013 for tool testing and training.

In November, 2009, OPG's Board of Directors approved the overall timeline and release strategy for the refurbishment of the Darlington NGS units, and funding for the preliminary planning phase which includes the development of infrastructure such as the Darlington Refurbishment Complex.

As part of a strategy to address other business needs, create efficiencies and maximize the occupancy of the facilities, the DRC will house other OPG programs and services including components of the Security Program, processing for new staff and a new Information Centre to replace the current facility on-site which will be used by the Nuclear Refurbishment organization. Further, during the refurbishment period, due to the increased volumes of construction staff and transport vehicles for material and equipment, it is advisable to limit public access to the site, to the extent feasible, during the refurbishment period. The DRC is a good location due to its proximity to the Darlington station, Waterfront Trail, Highway 401 and access roads.

Specifications for the DRC were finalized in 2010 and an RFP was prepared and issued. Based on the operating experience from other nuclear unit refurbishments underway a 70,000 sq. ft. Warehouse is included to meet the needs of two units being refurbished in a staggered pattern. The RFP closed on November 17, 2010. Proposals are currently being evaluated and form the basis of the Full Release amount. The contract will be awarded subsequent to this Full Release.

The following is a summary of the components and square footage of the proposed facility per the RFP Layout Plans:

| Component | Footage in Sq. Ft. |
|---|---|
| Office Space with 448 offices per block plans approved July 23, 2010. | 100,000 |
| TMB Mock-up area – with 50' Ceiling | 49,922 |
| Refurbishment Warehouse & Storage for Tools | 69,500 |
| Change Rooms, Cafeteria, Miscellaneous Training Facilities | 25,998 |
| Calibration, Welding and Fabrication Shops | 6,600 |
| Information Centre | 9,000 |
| Security Loading Bay | 9,450 |
| Aisle ways & corridors | 10,000 |
| **Total** | **280,470** |

The following is a breakdown of offices by floor and user:

| Offices by Floor & User | Refurbishment | Security | Public Affairs | Facilities | Total Offices |
|---|---|---|---|---|---|
| First Floor | 0 | 15 | 11 | 8 | 34 |
| Second Floor | 176 | 32 | 0 | 0 | 208 |
| Third Floor | 206 | 0 | 0 | 0 | 206 |
| **Total** | **382** | **47** | **11** | **8** | **448** |

## 4. ALTERNATIVES & ECONOMIC ANALYSIS

The following alternatives were considered:

### Base Case: Do Nothing (Contractor provides Training and Mock-up Facility)

Assume that the Retube and Feeder Replacement contractor has a training and mock-up facility in place and that OPG is not required to develop one.

Additionally, OPG would still need to construct a complex to meet Refurbishment Program needs such as training, additional project management offices in addition to the Construction management office to be build on the Darlington site, security in-processing for new hires (staff or contractors), and warehousing.

To do nothing would have the following impacts:

- Additional travel time and potential schedule delays for tooling modifications as the contractor facility would be further away.
- Increases the risk of a delay in the start of the Darlington Refurbishment outages and a risk of increased idle time on the third and fourth units to be refurbished due to the delayed start.
- Increased risk of critical path delays during the Darlington Refurbishment outages as a result of incomplete tool testing and training.
- Longer security processing of contractors/staff supporting Refurbishment as the DRC will include a security processing centre.

Due to the above noted impacts, the Base Case is not recommended.

**Alternative 1: Construct a Darlington Refurbishment Complex at the Clarington Energy Centre (Recommended Alternative).**

This alternative is the development of a 280,000 sq. ft. Darlington Refurbishment Complex ("DRC") on OPG owned lands in the Clarington Energy Centre to the west of the Darlington NGS site. This multi-purpose DRC will meet the needs and timeline of the Darlington Refurbishment project, including housing of the full-size mock-up, tooling, training and testing facility for fuel channel and feeder replacement work in preparation for refurbishment execution, a 70,000 sq. ft. warehouse to store refurbishment materials, an office area to accommodate the off-site project management team and support staff, a security in-processing centre, and a new information centre.

The Present Value of this option is -$96.6M. This NPV does not include the benefit of additional OPG usage of the DRC post refurbishment. Additionally, this NPV does not consider the benefit of reducing the refurbishment outage period; the DRC and mock-ups will be used to test tooling and train staff in order to reduce delays on the critical path of the refurbishment outage. Without the DRC and mock up, due to increased risks, the refurbishment duration would be expected to be longer. This benefit has not been considered, however, a savings of just 2 months per unit would result in a positive NPV for this project.

Alternative 1 is being recommended for the following reasons:

- The proposed location for the DRC at the Clarington Energy Centre is in close proximity to the Darlington site resulting in decreased transportation and relocation costs associated with the use of an alternate OPG-owned site, such as Wesleyville.
- The DRC consolidates facilities to meet Darlington Refurbishment needs, including project offices, warehousing, training and in-processing.
- Co-location of the project team into a single facility will improve communication, teamwork, and productivity during the Darlington Refurbishment project life cycle.
- A custom-built warehouse will meet the special refurbishment requirements such as floor loading and ability to ship secure loads of materials to site reducing need for Salley port upgrades at Darlington.
- The off-site complex will alleviate the Security processing burden and congestion for the station.
- As the facility would be built off-site, it would be a commercial facility that would have commercial value in the marketplace.

**Alternative 2: Construct a Darlington Refurbishment Complex with no Warehouse; and Lease Warehouse space.**

This alternative is the Darlington Refurbishment Complex as described in Alternative 1 except with no warehouse, resulting in a total footage of 211,000 square-feet. Approximately 69,000 sq. ft. of warehouse space with 20,000 sq. ft. of office/common services space for procurement staff would be required.

For financial evaluation, 89,000 sq. ft. of warehouse space, at current lease rates, was considered; however, OPG would lease a facility that would meet the needs of OPG that was of similar size but likely not exactly 89,000 sq. ft. This would have a bearing on the final lease rates. Assuming that the warehouse was in the Durham region, extra transportation and labour costs were included, however, based on two shipments every day, are not significant (about $18,000 per year). In addition to the ongoing rent, landlord operating costs and OPG operating costs, a same size loading bay, costing about $1M, would be required to meet the security requirement to fully enclose the transport truck and trailer. Based on the condition of the selected leased facility, additional leasehold improvements may also be required.

Not building a warehouse at the DRC could save approximately $10M (without escalation, contingency and capitalized interest) in project costs.

The Present Value of this option is -$97.7M, a difference of -$1.2M from recommended Alternative 1.

Alternative 2 is not recommended for the following reasons:

- The risks for damaging the tools would be increased due to transporting them from the leased warehouse to the Darlington Refurbishment Complex.
- Productivity could be impacted due to delayed shipment of tools from the leased warehouse as a result of unexpected traffic jam or accidents.
- Uncertainty in available warehouse space, requirements for leasehold improvements, and potential implications of a long term tenancy.

**Alternative 3: Construct a Darlington Refurbishment Complex on the Darlington NGS site.**

The Darlington Refurbishment Program explored the opportunity of locating the same Darlington Refurbishment Complex on the Darlington site.

This alternative is not recommended for the following reasons:

- The Present Value of this option is -$135.3M, a difference of -$38.7M from recommended Alternative 1. This is due to the higher cost to construct the facility on the Darlington Nuclear site.
- Due to limited land available on the Darlington site, the need to preserve the New Build lands and the increased traffic resulting from building the DRC on the Darlington site, this option is not preferred. The land should be used for personnel that directly support and interact with station workers reducing congestion on the Darlington site.
- Facilities constructed on the Darlington site would not have a commercial value (i.e. could not be sold) if no longer needed.

**The key variables for each alternative are summarized below:**

| | Alternative 1 | Alternative 2 | Alternative 3 |
|---|---|---|---|
| Location of DRC | CEC | CEC | DNGS |
| Refurbishment Warehouse | At the DRC | Lease<br>89,000 sq-ft | At the DRC |
| Total DRC Footage | 280,000 sq-ft | 211,000 sq-ft | 280,000 sq-ft |

**Financial Analysis $M (until Refurbishment Project Close-out):**

| | Base Case | Alt. 1 (Recommended) | | Alt. 2 | Alt. 3 |
|---|---|---|---|---|---|
| | | Full Costs | Incremental Costs | | |
| Initial Costs (Gross $M)* | N/A | 105.4 | 103.6 | 96.1 | 164.3 |
| NPV (2010 PV) | N/A | (98.1) | (96.6) | (97.7) | (135.3) |

* Excludes Operating Costs and Leasing Costs.

**Utilization of the DRC post-refurbishment, by IMS and/or other Nuclear Support organizations, and consolidation of lease costs (cost savings) were not included in the financial evaluations**, however, provides additional value to the recommended alternative.

Warehouse fitting, racking, and the reactor mock-up are excluded from the financial evaluations. These options are required for all options and are treated as separate projects within the Darlington Refurbishment Program. See Section 5 for further details.

**Additional Alternatives**

The following alternatives were considered and eliminated.

<u>Construct a Darlington Refurbishment Complex at another OPG location, i.e. Wesleyville</u>
The Darlington Refurbishment Program explored and discounted the opportunity of locating the DRC and warehouse at OPG's Wesleyville site due to the following reasons:

- This location would result in additional transportation costs (staff and material) and employee relocation costs.
- The Wesleyville location (37 kilometres from Darlington site) would not be a feasible location to accommodate the Refurbishment project team, as suggested by Operational Experience from other refurbishment projects.

<u>Construct a smaller Darlington Refurbishment Complex with less Office Space</u>
This alternative is the Darlington Refurbishment Complex as described in Alternative 1 except with no third floor offices, resulted in a total footage of 242,000 square-feet.

This alternative would save approximately $14M in construction and associated furniture and information telecommunication infrastructure (without escalation, contingency and capitalized interest).

Insufficient offices at the DRC will require alternative leased office space and/or use of modular offices. Reducing the planned office space will likely move costs to other project rather than reduce them. As well, having refurbishment staff at many locations will reduce efficiency.

It was assumed that the same 39,000 square-feet of office space on the third floor would have to be leased somewhere in the Durham Region to meet the Darlington Refurbishment office need. In addition to the ongoing rent, and operating costs, leasehold improvements of about $5.8M would be required.

This option is <u>not</u> recommended for the following reasons:

- There are risks in assuming a 39,000 square-feet office facility will be available for lease in the Durham Region for occupancy in mid 2013. The Durham Region office market is very small with no significant development.
- Having some staff located in a separate leased facility is against the original intent of co-location of the project team into a single facility to improve communication, teamwork, and productivity.
- There would be increased traveling time and costs from staff located at the separate leased facility.
- Reduced flexibility to consolidate staff from the Pickering location to co-locate to Darlington upon closure of the Pickering Nuclear Station.

## 5. THE PROPOSAL

The scope of this full release includes work associated with the design, construction, and commissioning of the DRC at the Clarington Energy Centre.

The work plan for Phase 3 includes:
a) Negotiations and awarding the Design-Build contract for the DRC,
b) Execution of the contract by the Proponent,
c) Owners oversight of the contract, including project controls, and internal OPG reporting,
d) Taking possession and furnishing the offices by OPG, and
e) Commissioning of the facility by the Proponent and OPG.

This proposal excludes:

1. Design, construction, delivery and installation of the reactor mock-ups will be procured under a separate agreement and project. The DRC, however, will house the reactor mock-ups. Costs to service the property after construction and potential increased electrical service, floor work (trenches, conduits), until further defined, to house and support the mock-up will be included in the reactor mock-up project.
2. Racking, carousels or storage units in the warehouse and associated changes to lighting, HVAC, and sprinklers, as required. This will be managed as a separate project.
3. Equipment & infrastructure such as: forklifts, carts, welders, security x-ray machines, relocation changes for equipment or requirements of the x-ray machine & equipment, and tools and devices to support specific work group needs.
4. Information Centre custom artwork, exhibits or decals.
5. Internet wireless service in the building.
6. Staff relocation or move costs.

Project Assumptions include:

1. Floor loading for the reactor/fuel channel mock-up (85' x 259'), approximately 21,900 square-feet, would be 2400 Kg/square-metre. All other areas in the warehouse would be 440 lbs./sq.ft. live loads.
2. All classrooms, briefing rooms, and workstations are located in the office area of the building.
3. There are no mezzanines for storage of equipment or for use as classrooms in the warehouse.

The key milestones of this project are summarized below.

**Phase 2: Site Servicing and RFP Phase (Funded by Phase 2 Partial Release)**

Municipal Services

| | |
|---|---|
| • Finalize Clarington Subdivision Agreement | Completed July 27, 2010 |
| • Finalize Regional Subdivision & Servicing Agreement | October 29, 2010 |
| • Award Tender for Site Servicing – Clarington (1) | January 31, 2011 |
| • Award Tender for Site Servicing – Durham Region | January 31, 2011 |
| • Site Servicing (2) | February, 2011 to June 30, 2013 |

Darlington Refurbishment Complex RFP

| | |
|---|---|
| • Prepare DRC Specification | Completed |
| • Full Release BCS Approved | December 16, 2010 |
| • Select EPC Contractor | January 31, 2011 |

**Phase 3: Design, Construct, Commission TMB Complex (This Full Release)** (3)

| | |
|---|---|
| • Award EPC Contract | Mid March, 2011 |
| • Design Complete | June 30, 2011 |
| • Construction Start | July 1, 2011 |
| • In-Service | July 1, 2013 |

(1) Both Clarington and Durham Region have confirmed that site services required for construction will be in place by June 2011 with all site servicing in place at time of full in-service of the DRC.

(2) The municipal services and the internal road works for the OPG CEC property and the municipal services to DNGS will be constructed during 2011 and the additional works scheduled for 2012 to 2013, are related to the South Service Road upgrades and local intersection improvements.

(3) Dates for Phase 3 are indicative, and were the basis for the RFP; however, exact timing will be confirmed upon selection of the EPC Contractor.

## 6. QUALITATIVE FACTORS

Other benefits associated with this project are as follows:

- The DRC provides additional benefits to the Darlington NGS station due to the water main design, water and sanitary sewer services to the site. This will provide the ability for the station to connect to regional water and sanitary sewer services and mitigating environmental concerns related to the operation of the waste treatment facility on the Darlington site. The addition of a sewage line addresses long standing MOE concerns with sewage discharge and removes the requirement for training and qualifying Nuclear Operators under Provincial license standards for Sewage Treatment Plant operations. Currently the station has only one source of domestic water; thus, the scheduling of water outages is difficult. The new water main design would eliminate the need for future domestic water outages at the station.
- OPG owned warehouse and offices at the DRC will add value as future warehouse and office space for Nuclear support functions, including Inspection and Maintenance Services Division, and in support of post refurbishment operations at Darlington.
- The DRC would follow the Leadership in Energy and Environmental Design Green Building (LEED) Canada guideline for green buildings that improves occupant well being, environmental performance and economic benefits through efficiency and sustainability. OPG has set an objective of a LEED 'Silver' rating for the building. Clarington recognizes

the community benefits of a LEED certified building and it may offer a reduced development charge fee.

- The DRC strengthens OPG's commitment to the Clarington community and Durham Region.

## 7. RISKS

The following project risks are being managed with respect to this Project:

**Table - Risk Management and Contingency Plan**

| Risk Class | Description of Risk | Risk Probability | Risk Impact | Risk Management Strategies: Avoidance/Mitigation/Correction |
|---|---|---|---|---|
| Cost | Service cost increases due to change in scope after the Pre-submission Consultation. | Low | Low | OPG, Clarington and Durham have had several meetings to discuss the amount of supporting plans and technical reports required to complete the submission. |
| Cost | Higher than planned site servicing costs. | Low | Medium | The site servicing costs is based on an engineering estimate prepared by an external party and includes a [redacted] OPG has included [redacted] to deal with scope changes. |
| Cost | Higher than planned design and construction costs (Phase 3 risk) | Medium | Medium | The Full Release estimate represents the highest bid of the proponents and is based on project needs as identified in the RFP specifications. A [redacted] has been added to the Full Release estimate to deal with scope changes. |
| Cost | Costs will increase if the exclusions noted in Section 5 above are brought into the scope of this contract. | High | High | a) Scope and manage exclusions as a separate contract, where appropriate.<br>b) Where appropriate and possible, scope and estimate exclusions early in the time period of this PO to minimize re-work. |
| Schedule | Delay in municipal approvals. | Low | Low | Clarington has verbalized support for the Site development and the development does not require changes to the Official Plan or Zoning By Law. Clarington has indicated priority processing for OPG development application. A delay is not anticipated but ongoing discussions with Clarington will ensure a timely delivery. |
| Schedule | Delay in awarding the tender and, hence, the completion of the site services, that are sensitive to seasonal construction, could have cost and schedule implications. | High | High | Provide the required documents and security bonds in a timely manner required for the tender. Escalate to Clarington Mayor and Regional Chair if staff is unable to resolve OPG's concerns on timing to tender for the works. |

**Table - Risk Management and Contingency Plan**

| Risk Class | Description of Risk | Risk Probability | Risk Impact | Risk Management Strategies: Avoidance/Mitigation/Correction |
|---|---|---|---|---|
| Schedule | Delay in the completion of the project (available for service date – July 2013) | Medium | High | There are only 3 months of float between the AFS and the need date for the R&FR contractor. Any delay beyond 3 months may reduce the testing and tool development time for the R&FR contractor increasing Refurbishment project execution risk. The EPC contract will require on-time delivery of this project. This risk will be re-evaluated closely upon awarding the EPC contract. In particular, the EPC contractor will need to submit their site plans as soon as possible after receipt of PO to ensure minimum delay as the submission is reviewed by Municipality. |

## 8. POST IMPLEMENTATION REVIEW (PIR) PLAN

A simplified PIR will be carried out within one year of the completion of Phase 3, consistent with the Corporate PIR procedure.

The PIR will be an independent and systematic performance evaluation of the project for these objectives:

- Assess the realization of the project benefits;
- Review project plan, implementation and operational performance;
- Review BCS – major assumptions, economic and financial evaluations looking back from results, for future decisions;
- Review project risk management; and
- Identify lessons learned for future improvement.

| Type of PIR: | Target Project In Service date: | Target PIR Approval date: | PIR Responsibility (PIR Co-ordinator): |
|---|---|---|---|
| **Simplified** | **28-Jun-13** | **30-June-14** | Director, Planning & Project Control<br>Nuclear Refurbishment |

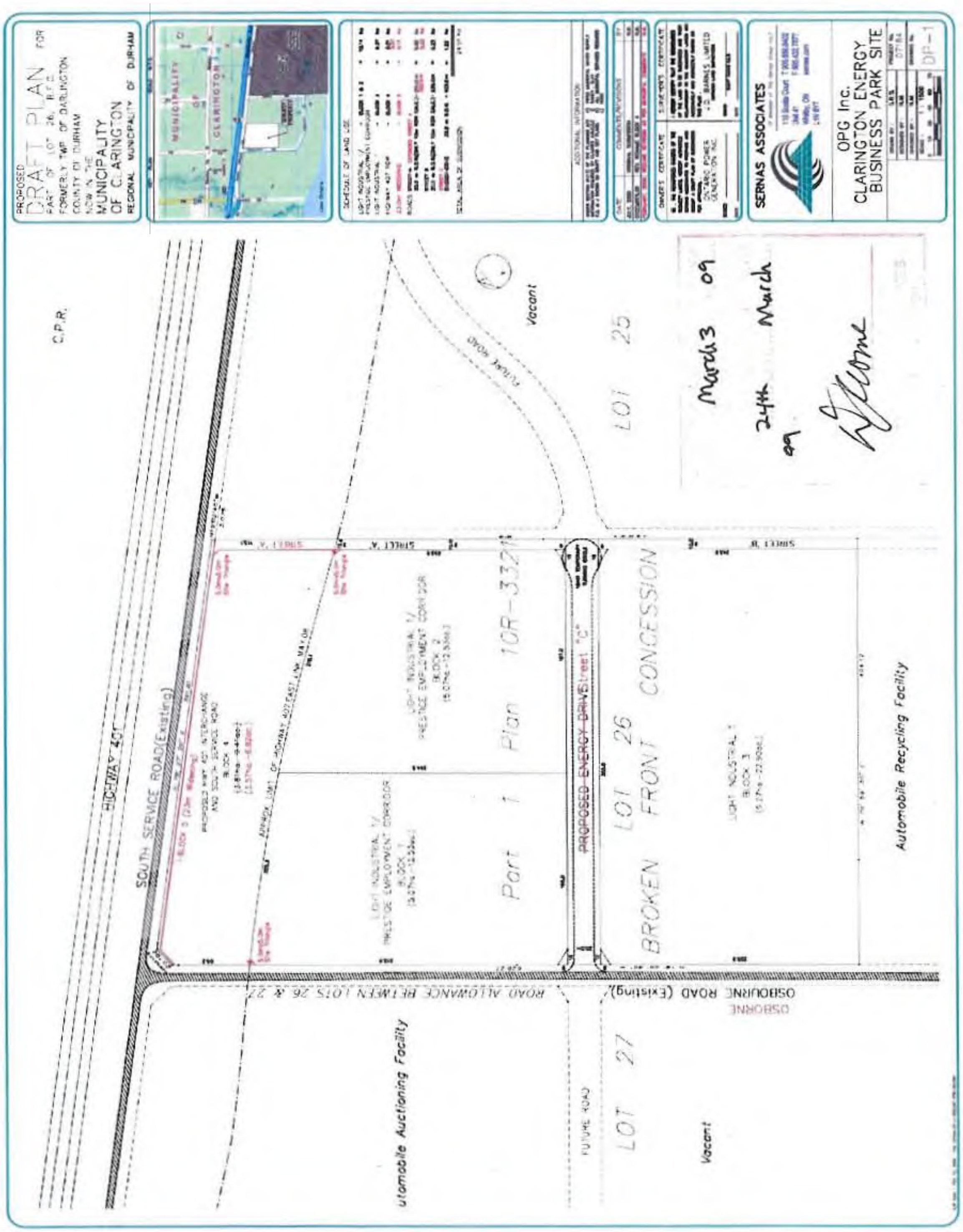
| | Measurable Parameter | Current Baseline | Target Result | How will it be measured? | Who will measure it? (person/group) |
|---|---|---|---|---|---|
| 1. | Cost – Cost of Site Servicing | $15.8M including contingency and escalation | $15.8M | Final Project Cost Report | Director, P&PC |
| 2. | Cost – Cost of DRC Construction | $70.8M Including apportionment of contingency and escalation, excluding furniture and IT | $70.8M | Final Project Cost Report | Director, P&PC |
| 3. | Schedule – In-Service date | July 2013 | July 2013 | Date of Occupancy Permit | Director, P&PC |
| 4. | LEED Certification | Achieves LEED Silver | Achieves LEED Silver Certification by June 30, 2014 | Receipt of certification | VP, Real Estate Services |
| 5. | Occupancy | Occupied by NR staff within 3 months of in-service | Oct 2013 | Oct 2013 | Director, P&PC |

## APPENDIX A: Site Plan

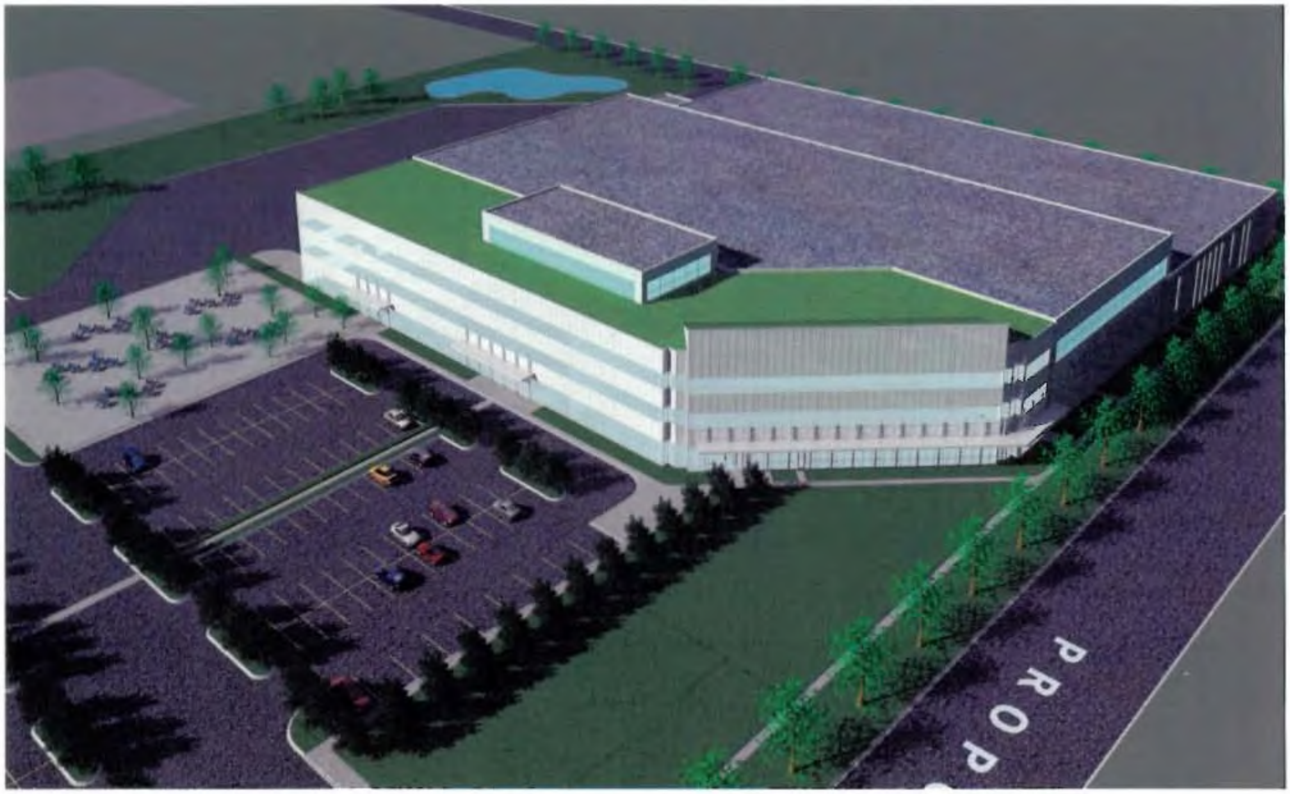
DATE OF PHOTOGRAPHY: MAY 2007
DATA SOURCE: OPG

## APPENDIX B: Approved Draft Plan of Sub-Division

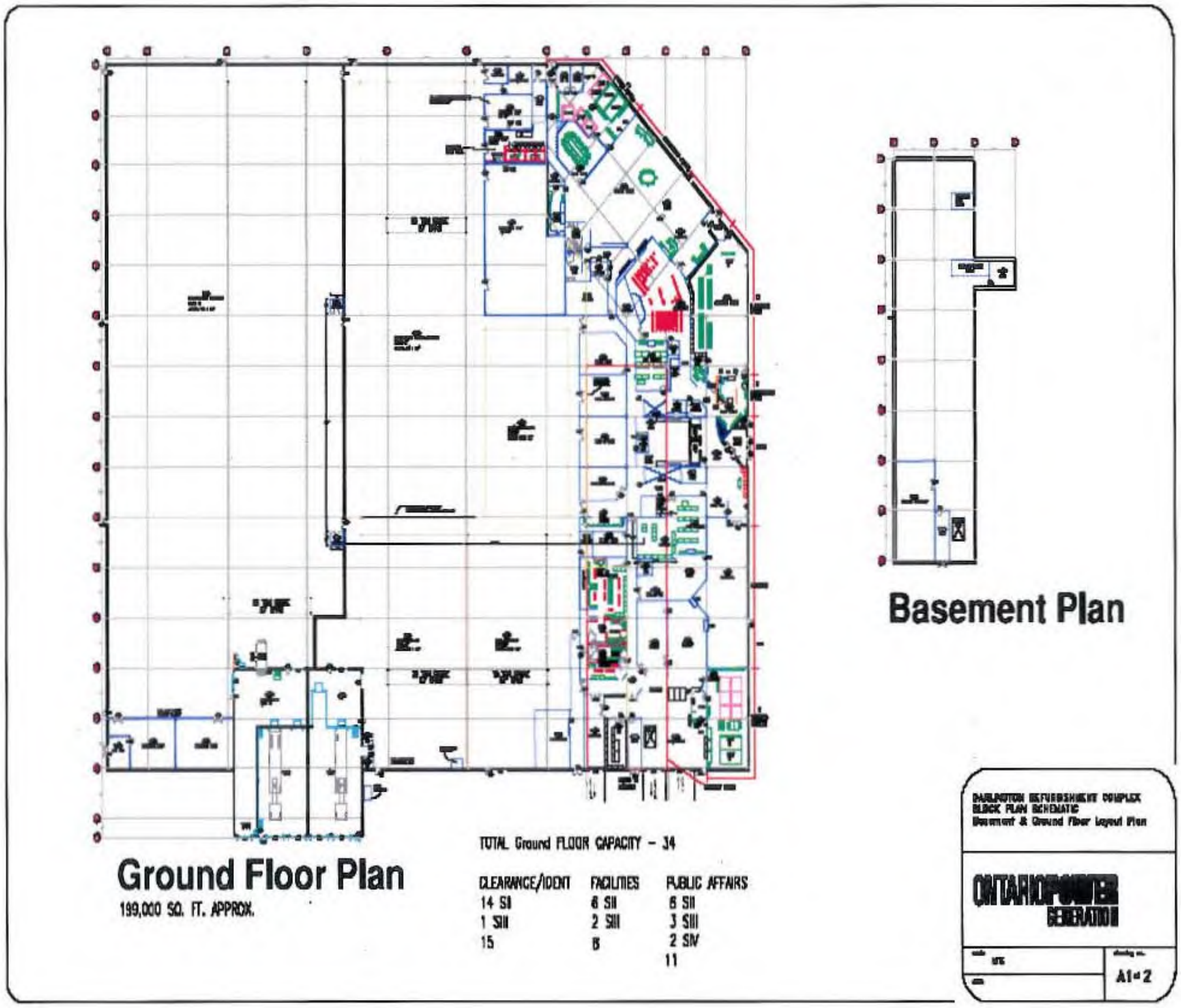
The following draft plan of sub-division was approved by the Municipality of Clarington on March 24, 2009:



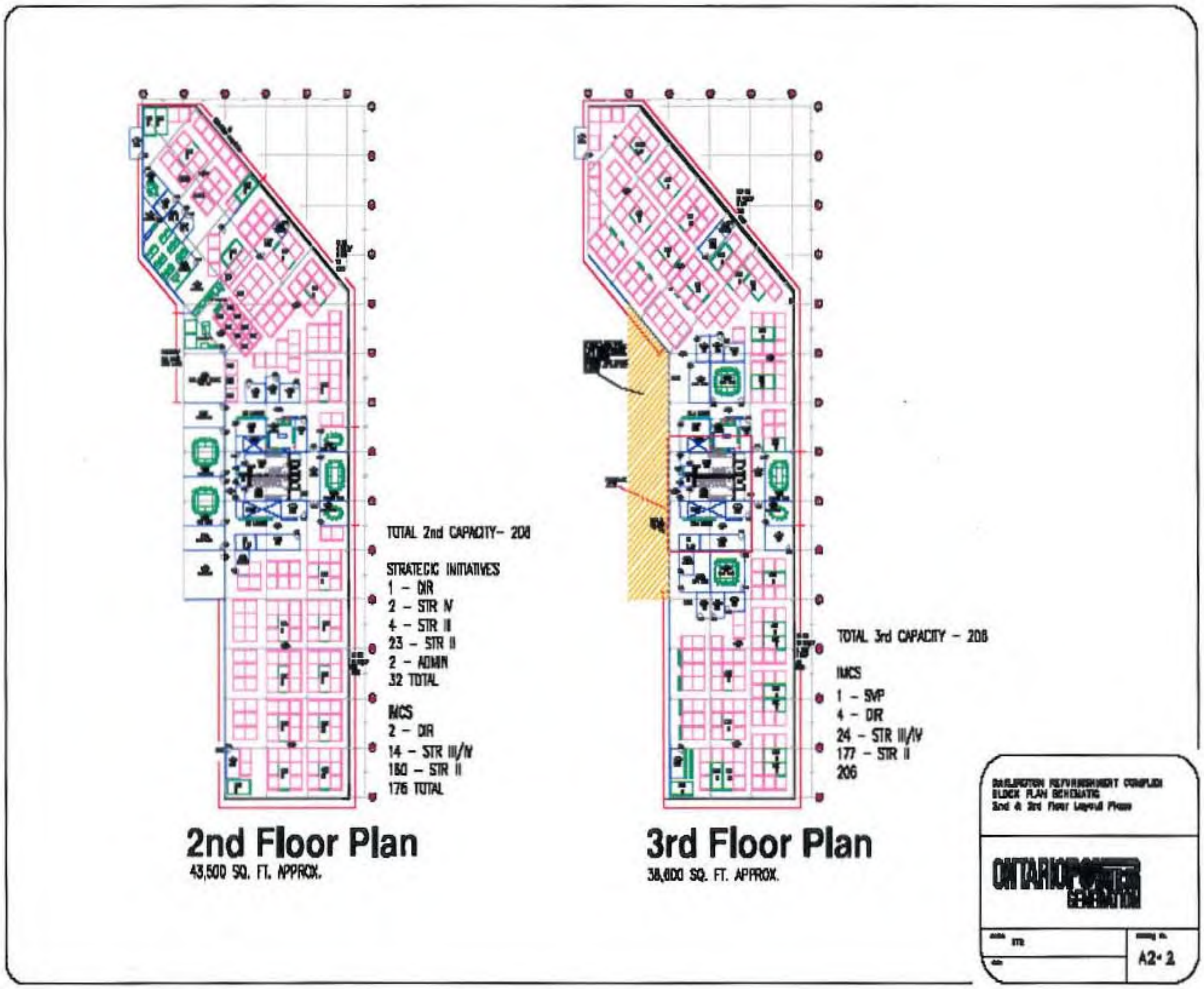
## APPENDIX C: Proposed Site Plan



## APPENDIX D: Ground Floor Layout Plan



## APPENDIX E: Second & Third Floors Layout Plans



## APPENDIX F: Summary of the Darlington Refurbishment Complex Needs Statement

The following is a summary of the needs of the DRC facility:

| Organization | Function | Business Drivers |
|---|---|---|
| Nuclear Refurbishment | • Training for the re-tube and feeder replacement (R&FR) project<br>• Mock-ups for training and equipment testing<br>• Support R&FR prototype tool testing and development, as well as storage for R&FR tools.<br>• Offices for project management team and support staff.<br>• Warehouse in close proximity to site and mock-up to store tools, retube and other components with secure loading capability | • Address a need that provides training, mock-up, and testing in support of the Darlington Refurbishment timeline.<br>• Provide facilities to accommodate the OPG project Management team.<br>• Eliminate leasing costs. |
| IMS | • Location and design satisfies long-term business plan for IMS, enabling the discontinuance of multiple leases offsetting ongoing operational costs. | • Consolidate IMS Operations starting in 2024 upon completion of refurbishment.<br>• Eliminate leases |
| Information Centre | • CEC is a good location for a temporary facility for the Information Centre due to its proximity to the Darlington station, Waterfront Trail, natural vegetation, 401 and access roads, including access roads to the station. | • Accommodates the Information Centre which will be over 30 years old when refurbishment ends, it will most likely at end of service life without significant re-investment. |
| Security | • Enhanced efficiency and effectiveness through consolidation of Nuclear Security Strategic Initiatives (Tactics and Training, Programs), Security Clearance, and Identification Office functions (badging, parking passes, etc.) | • Eliminate leasing costs.<br>• Greater efficiencies and effectiveness in delivery of security program processing |
| Training | • Facilitation of Nuclear General Employee Training process for new hires (staff/contractors). | • Increased access and efficiency in Nuclear General Employee Training processing |

The following is a summary of the components and square footage of the proposed facility per RFP Layout Plans:

| Component | Footage in Sq. Ft. |
|---|---:|
| Office Space for workstations/offices for 448 staff per block plans approved July 23, 2010. | 100,000 |
| TMB Mock-up area – with 50' Ceiling | 49,922 |
| Refurbishment Warehouse & Storage for Tools | 69,500 |
| Change Rooms, Cafeteria, Misc Training Facilities | 25,998 |
| Calibration, Welding and Fabrication Shops | 6,600 |
| Information Centre | 9,000 |
| Security Loading Bay | 9,450 |
| Aisle ways & corridors | 10,000 |
| **Total** | **280,470** |

# For Internal Project Cost Control

## APPENDIX G: Phase 2 Partial Release Estimate

| | | Phase 1<br>Partial Release<br>Approved $1,244k | | | Phase 2<br>Partial Release<br>Approved at March 2010 Board Meeting | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Actual Cost (k$) | | | Estimated Costs (k$) | | | | | | | |
| | Year | 2008 | 2009 | Total | 2010 | 2011 | 2012 | 2013 | Total | | % | |
| | Engineering Design | | 270 | 270 | 56 | 25 | 25 | 25 | 131 | | 1 | |
| | Consultants/Application Fees | 150 | 339 | 489 | | | | | | | | |
| | Subdivision Agreement | | | | 199 | 315 | 57 | 5 | 576 | | 3 | |
| | Construction | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| | Other Contracts<br>- Hydro One WAN Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| | RFP Specification & Tender | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| | Owner's Contingency [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| | Cost Escalation (2%/year) | | | | 0 | 214 | 163 | 20 | 397 | | 2 | |
| | Interest on Capital (6%) | | | | 22 | 373 | 855 | 618 | 1,868 | | 10 | |
| | **Total Project** | **150** | **609** | **759** | **1,332** | **11,294** | **5,053** | **966** | **18,645** | | 100 | |
| | | **Phase 1 (Capital)<br>$759k** | | | **Phase 2 (Capital)<br>$18,645k** | | | | | | | |

**Project Estimates Approved By:**

Ray Davies
Ray Davies
Real Estate Strategy Manager
Real Estate & Services

Dec 7/10.
Date

## Assumptions

Following are the key assumptions used during the development of this release:

1. Phase 2 cost estimates were provided by OPG consultant Sernas Associates, and are in 2010 dollars($).
2. Phase 2 work on Subdivision Agreement, Site Servicing, DRC RFP Specification and Tender are treated as capital costs.
3. Owner's Contingency allowance is based on [redacted]% of total direct costs.
4. Cost escalation was added to total costs including contingency based on 2% per annum.
5. Interest charge on capital is based on 6% per annum, and Phase 2 will be 100% in-service July 1, 2013.
6. No cost sharing from Durham, Clarington or others assumed at this time.

In 2007 the following costs were incurred as the result of the land purchase, this is excluded from above estimate.

| | |
|---|---|
| Land Purchase | $4,923 K |
| Real Estate Commission | 98 |
| Land Transfer Tax | 72 |
| Realty Taxes | 1 |
| Consultants for Due Diligence | 87 |
| **Total 2007 Costs** | **$ 5,181 K** |

## APPENDIX H: Phase 3 Full Release Estimate

The following chart summarizes the Full Release estimate for Phase 3, the design and construction of the DRC and includes an analysis of estimate change since the March 2010 Partial Release.

| | Phase 3<br>DRC Design and Construct<br>Release Estimate (+15%/ -10%) | | | | | |
|---|---|---|---|---|---|---|
| | Estimated Costs (k$) | | | | | |
| **Year** | **2010** | **2011** | **2012** | **2013** | **Total** | **%** |
| **Capital Costs** | | | | | | |
| Design and Construction | | 17,021 | 28,511 | 14,468 | 60,000 | 70 |
| Commissioning | | | | 130 | 130 | 0 |
| LEED Consultant | | | 100 | 250 | 350 | 0 |
| Other Contracts | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| IT & Furniture for Refurb Offices | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Owner's Contingency [redacted] | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Cost Escalation (2%/year) | | 56 | 341 | 456 | 853 | 1 |
| Interest on Capital (6%) | | 537 | 2,206 | 2,035 | 4,778 | 6 |
| **Total Capital Costs** | | **20,397** | **39,496** | **24,412** | **84,306** | **98** |
| | | | | | | |
| **OM&A Costs** | | | | | | |
| IT & Furniture for other offices | | | [redacted] | [redacted] | [redacted] | [redacted] |
| Owner's Contingency [redacted] | | | [redacted] | [redacted] | [redacted] | [redacted] |
| Cost Escalation (2%/year) | | | 28 | 53 | 82 | 0 |
| **Total OM&A Costs** | | | **726** | **926** | **1,652** | **2** |
| | | | | | | |
| **Total Project** | **0** | **20,397** | **40,222** | **25,338** | **85,958** | **100** |

**Project Estimates Approved By Project Manager:**

Dec 7, 2010

Don Seedman
Manager, Facilities & Projects
Real Estate & Services

Date

**Assumptions**

Following are the key assumptions used in the above Full Release estimates (based on highest RFP bid price):

1. The total design & construction costs for Phase 3 equates to $259 per square-feet at 2010$ for non-warehouse and $100 per square-feet for warehouse & loading bay, based on the gross building area of 280,000 square-feet.

2. Owner's Contingency allowance is based on [redacted] of IT & Furniture and [redacted] of design & construction direct costs.
3. Cost escalation was added to total costs including contingency based on 2% per annum.
4. Interest charge on capital is based on 6% per annum, and Phase 3 will be 100% in-service July 1, 2013.
5. Annual operating costs is about $5.3M in 2010$ including utility costs, property taxes, facilities and IT services costs, commencing July 1, 2013; It equates to $10 per square-feet for warehouse/Mock-ups/Shops and $29 per square-feet for offices, Information Centre and other miscellaneous facilities.
6. Further development of the DRC design requirements, since the March Definition Phase release, has led to additional project design & construction costs of approximately $7M (excluding capitalized interest and contingency) due to the following:

Clarington Energy Centre related requirements:

| | | |
|---|---|---|
| a) | Prescribed requirements for external finishes, storm water location, etc. | (+$1.3M) |
| b) | Unexpected site conditions: sub-soil investigation revealed a higher than anticipated water table, requiring dewatering during construction, foundation construction changes and on-going maintenance | (+$0.7M) |

OPG newly identified requirements:

| | | |
|---|---|---|
| a) | Security upgrades around the Loading Bay | (+$1.0M) |
| b) | Hallways and walkways | (+$1.0M) |
| c) | Increased Refurbishment warehouse space of 30,000 square-feet | (+$3.0M) |

Item (c) is an increased scope based on OPEX from other current refurbishments and further consideration of Darlington Refurbishment's unit overlap execution scenario.

## APPENDIX I: Cost Variances from Business Plan

The following summarizes the cost variances from the 2010 to 2014 approved business plan, as related to the Darlington Refurbishment Complex project:

Total Investment Cost: $105,362k ($103,710k Capital & $1,652k OM&A)
(Including $19,686k Capital previously approved)

### 1) Capital Cost Summary

| Capital Funding $ 000's | | LTD Dec 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | Total |
|---|---|---|---|---|---|---|---|---|
| Current Release | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Total** | 759 | 6,489 | 7,098 | 4,480 | 860 | 0 | 19,686 |
| This Release | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Total** | 0 | (5,157) | 24,593 | 40,069 | 24,519 | 0 | 84,024 |
| Total Release | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Total** | 759 | 1,332 | 31,691 | 44,549 | 25,379 | 0 | 103,710 |
| Future Release | Project Costs | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Contingency | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | **Total** | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Project Costs** | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Contingency** | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Total** | | 759 | 1,332 | 31,691 | 44,549 | 25,379 | 0 | 103,710 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Approved 2010-2014 BP | | 8,327 | 25,968 | 22,535 | 23,391 | 10,280 | 90,500 |
| **Variance to Business Plan** | | (6,994) | 5,724 | 22,014 | 1,987 | (10,280) | 13,210 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Removal Cost (Above) | | 0 | 0 | 0 | 0 | 0 | 0 |
| Inventory W/O | | 0 | 0 | 0 | 0 | 0 | 0 |
| Spare Parts in Inventory | | 0 | 0 | 0 | 0 | 0 | 0 |

## 2) OM&A Cost Summary

| OM&A Funding $ 000's | | LTD Dec 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | Total |
|---|---|---|---|---|---|---|---|---|
| Current Release | Project Costs | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Contingency | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| This Release | Project Costs | 0 | 0 | 0 | [redacted] | [redacted] | [redacted] | [redacted] |
| | Contingency | 0 | 0 | 0 | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Total** | **0** | **0** | **0** | **726** | **926** | **0** | **1,652** |
| Total Release | Project Costs | 0 | 0 | 0 | [redacted] | [redacted] | [redacted] | [redacted] |
| | Contingency | 0 | 0 | 0 | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Total** | **0** | **0** | **0** | **726** | **926** | **0** | **1,652** |
| Future Release | Project Costs | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Contingency | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **Project Costs** | | **0** | **0** | **0** | [redacted] | [redacted] | [redacted] | [redacted] |
| **Contingency** | | **0** | **0** | **0** | [redacted] | [redacted] | [redacted] | [redacted] |
| **Total** | | **0** | **0** | **0** | **726** | **926** | **0** | **1,652** |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Approved 2010-2014 BP | | 0 | 0 | 0 | 0 | 0 | 0 |
| **Variance to Business Plan** | | **0** | **0** | **726** | **926** | **0** | **1,652** |

The Darlington Refurbishment Complex Phase 3 conceptual estimates plus capitalized interest and contingency were included in the Darlington Refurbishment Campus Plan submitted 2011-2015 Business Plan.

## APPENDIX J: Project Variance Analysis

The following summarizes the variances from previous release:

| Phase 2 Partial Release Estimate | | | | | |
|---|---|---|---|---|---|
| **Capital ($000)** | **LTD Oct 2010** | **Last BCS Feb 2010** | **This BCS Dec 2010** | **Variance** | **Comments** |
| Engineering Design | $33 | $131 | $131 | $0 | |
| Consultants/Application Fees | [redacted] | [redacted] | [redacted] | [redacted] | |
| Subdivision Agreement | [redacted] | [redacted] | [redacted] | [redacted] | |
| Construction | [redacted] | [redacted] | [redacted] | [redacted] | |
| Other Contracts/Costs - Hydro One WAN | [redacted] | [redacted] | [redacted] | [redacted] | |
| RFP Specification & Tender | [redacted] | [redacted] | [redacted] | [redacted] | Utilization of project contingency |
| Owner's Contingency [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | Contingency reallocated to RFP |
| Cost Escalation (2% per year) | [redacted] | [redacted] | [redacted] | [redacted] | 2010 site servicing work delayed to 2011 |
| Interest on Capital (6%) | [redacted] | [redacted] | [redacted] | [redacted] | Delay of work to 2011 |
| **Total Phase 2 Project Costs** | **$898** | **$18,927** | **$18,645** | **-$283** | |

| Phase 3 Full Release Estimate | | | | | |
|---|---|---|---|---|---|
| **Capital ($000)** | | **Last BCS Feb 2010** | **This BCS Dec 2010** | **Variance** | **Comments** |
| Design & Construction | | [redacted] | [redacted] | [redacted] | Warehouse increased by 30K sq-ft; Added 10K sq-ft loading bay and 10K sq-ft aisleways & corridors; Prescribed CEC requirements in external finishes and storm water location, and unexpected site conditions. |
| Commissioning | | [redacted] | [redacted] | [redacted] | Higher costs due to larger footage |
| LEED Consultant | | [redacted] | [redacted] | [redacted] | Higher costs due to larger footage |
| Other Contracts | | [redacted] | [redacted] | [redacted] | Higher costs due to larger footage |
| Capitalized IT & Furniture | | [redacted] | [redacted] | [redacted] | Reclassification of NR IT & Furniture Costs |
| Owner's Contingency | | [redacted] | [redacted] | [redacted] | Higher contingency due to higher direct costs |
| Cost Escalation (2% per year) | | [redacted] | [redacted] | [redacted] | Escalation included in current D&C Costs |
| Interest on Capital (6%) | | [redacted] | [redacted] | [redacted] | Higher interest due to higher direct costs |
| **Total Capital Costs** | | **$68,166** | **$84,306** | **$16,140** | |
| **OM&A ($000)** | | **Last BCS Feb 2010** | **This BCS Dec 2010** | **Variance** | **Comments** |
| IT & Furniture for Offices | | [redacted] | [redacted] | [redacted] | Reclassification of NR IT & Furniture Costs |
| Owner's Contingency [redacted] | | [redacted] | [redacted] | [redacted] | Lower contingency due to lower direct costs |
| Cost Escalation (2% per year) | | [redacted] | [redacted] | [redacted] | Lower escalation due to lower direct costs |
| **Total OM&A Costs** | | [redacted] | [redacted] | [redacted] | |
| **Total Phase 3 Project Costs** | | **$80,892** | **$85,958** | **$5,066** | |

Note: The Feb 2010 BCS represents a total release of $19.7M including $0.8M for Phase 1, Land Development and $18.9M for Phase 2, Site Servicing and Contract Tendering of this project.

## APPENDIX K: Financial Model Assumptions

Following are the key assumptions used during the modelling of the Project:

**Project Cost Assumptions:**

1. The total area of the complex is estimated at 280,000 square-feet; 448 staff.
2. The total design & construction costs for Phase 3 equates to $259 per square-feet at 2010$ for non-warehouse and $100 per square-feet for warehouse & loading bay, based on the gross building area of 280,000 square-feet.

**Financial Assumptions:**

3. The discount rate is 7% (Regulated Nuclear asset) for this strategic investment decision.
4. The Ontario CPI (2% per year) is used to convert the cost estimates in 2010$ to "Dollars of the year".
5. CCA Rate 6% or Class 1* is being used for new non-residential buildings.

**Project Life Assumptions:**

6. The Phase 2 Municipal Site Servicing will be completed by July 1, 2013.
7. The design, construction and commissioning of the DRC at the CEC will take about 2 1/2 years.
8. The DRC at the CEC will be in-service by July 1, 2013.

**Operating Cost Assumptions:**

9. Annual operating costs for the DRC is estimated at $5.3M in 2010$ including utility costs, realty taxes, facilities and IT services costs, commencing July 1, 2013. It equates to $10 per square-feet for warehouse/Mock-ups/Shops and $29 per square-feet for offices, Information Centre and other miscellaneous facilities, based on the gross building area of 280,000 square-feet.

**Other Assumptions:**

10. The following are not included in the cost estimates:
    - Reactor mock-ups Including the design, construction, delivery and installation will be procured under a separate agreement and project. Costs to service the property after construction and potential increased electrical service, until further defined, to house & support the mock-up.
    - Floor work (trenches, conduits) to support the internal of the mock up area or the warehouse.
    - Racking, carousels or storage units in the warehouse or support infrastructure.
    - Equipment such as; forklifts, carts, welders, security x-ray machines, relocation changes for equipment or requirements of the x-ray machine & equipment, and tools and devices to support specific work group needs.
    - Information Centre custom artwork or decals.
    - Internet Wireless service in the building.
    - Staff relocation costs, incremental travel costs or warehouse transportation costs.
    - Office moving costs of affected organizations such as Nuclear Refurb, Information Centre & Security

11. Potential cost recovery of some of the servicing costs if other developers build within the CEC is not included in this evaluation.

12. Incremental travelling time and costs are not included in the NPV calculation for the leased office space alternatives.

## APPENDIX L: Indicative Schedule – Darlington Refurbishment Complex (Recommended Alternative)

Darlington Refurbishment Complex

| ID | Task Name | Start | Finish | 2010 | | | | 2011 | | | | 2012 | | | | 2013 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| 1 | Phase 2: Site Services and RFP Spec | | | | | | | | | | | | | | | | | | |
| 2 | **Muncipal Services** | Mar-10 | Jun-13 | | | | | | | | | | | | | | | | |
| 3 | Finalize Regional Subdivision & Servicing Agreement | | Oct-10 | | | | ▨ | | | | | | | | | | | | |
| 4 | Award Tender for Site Servicing - Clarington | | Jan-11 | | | | | ▨ | | | | | | | | | | | |
| 5 | Award Tender for Site Servicing - Durham Region | | Jan-11 | | | | | ▨ | | | | | | | | | | | |
| 6 | Site Servicing | Feb-11 | Jun-13 | | | | | ▨ | ▨ | ▨ | ▨ | ▨ | ▨ | ▨ | ▨ | ▨ | ▨ | | |
| 7 | **Darlington Refurbishment Complex RFP** | Mar-10 | Dec-10 | | | | | | | | | | | | | | | | |
| 8 | Prepare DRC Specification (Completed) | | Sep-10 | | | ▨ | | | | | | | | | | | | | |
| 9 | Full Release BCS Approved | | Dec-10 | | | | ▨ | | | | | | | | | | | | |
| 10 | Select EPC Contractor | | Jan-11 | | | | | ▨ | | | | | | | | | | | |
| 11 | Phase 3: Design , Construct & Commission DRC | | | | | | | | | | | | | | | | | | |
| 12 | Award EPC Contract | | Mar-11 | | | | | ▨ | | | | | | | | | | | |
| 13 | Design Complete | Mar-11 | Jun-11 | | | | | ▨ | ▨ | | | | | | | | | | |
| 14 | Construction Start | Jul-11 | Jul-13 | | | | | | | ▨ | ▨ | ▨ | ▨ | ▨ | ▨ | ▨ | ▨ | | |
| 15 | In-Service | | Jul-13 | | | | | | | | | | | | | | ▨ | | |

**ONTARIO POWER GENERATION**

**OPG Confidential**

**Business Case Summary**

## Darlington Water and Sewer Project 10 - 73802 (Capital)
## Partial Release Business Case Summary NK38 - BCS - 72700 - 10008 - R000

| Name / Title / Phone | Location | Action | Signature | Date |
|---|---|---|---|---|
| Jack Ballard<br>Director, Infrastructure & Misc Projects<br>701-2648 | P72-1 | Prepare BCS | | July 11, 2011 |
| Gary Rose<br>Director, Planning and Control<br>Nuclear Refurbishment<br>703-5423 | O11-2 | Review BCS | | July 13, 2011 |
| Mark Arnone<br>Vice President, Refurbishment Execution, Nuclear Refurbishment<br>703-5404 | O11-2 | Review BCS | | 13 JULY 2011 |
| for<br>Jamie Lawrie<br>Director, Nuclear Finance<br>702-5086 | P82-3 | Review BCS | | 14 Jul 11 |
| Randy Leavitt<br>Vice President, Nuclear Finance<br>702-5177 | P82-3 | Review BCS | RLeavitt | July 14, 2011 |
| Don Power<br>Vice President, Corporate Investment and Planning<br>400-7172 | H07-G05 | Review BCS | | July 21/11 |
| Dietmar Reiner<br>Senior Vice President,<br>Nuclear Refurbishment<br>703-5400 | O11 | Submit BCS | | Jul |
| Albert Sweetnam<br>EVP, Nuclear Projects and support<br>400-7537 | H17-G25 | Concur with BCS | for | July 28/2011 |
| Donn Hanbidge<br>SVP & Chief Financial Officer<br>400-2395 | H19-F27 | Approve BCS | D Hanbidge | August 2/2011 |
| Tom Mitchell<br>President & Chief Executive Officer<br>400-2121 | H19-A24 | Approve BCS | | August 8, 2011 |
| Carolyn Sicard<br>Nuclear Investment Management<br>702-4082 | P82-3B6.2 | Return for Distribution | | |

# ROUTING SHEET

## Darlington Water and Sewer Project 10 - 73802 (Capital)
## Partial Release Business Case Summary NK38 - BCS - 72700 - 10008 - R000

### 1/ RECOMMENDATION:

We recommend a **Partial** Release of an **additional $16.3** Million **Capital** (Partial Release Estimate of $19 Million minus $2.73 Million under expenditure from the Developmental Release) to fund the:

- design, procurement and construction of the new main water lines,
- design, procurement and construction of the sanitary sewer line to the municipality,
- design of the water and sanitary sewer lines to the new Campus Plan and Refurbishment facililites on DNGS site.

Approval of this request will bring the total to date funding to **$20.3** Million including a contingency of [redacted] Million. The total project is estimated to cost **$36** Million including a contingency of [redacted] with an estimated project closeout completion date of 6/30/2015. There are also estimated removal costs of $2.1 Million.

The business Objectives of this **Sustaining** project are as follows:

a) To ensure adequate and reliable domestic and fire water supply and sanitary sewer system capacity for the continued operation of the station for an additional 25 to 30 years of post refurbishment life.
b) To ensure fire water pressure remains in compliance with Ontario Building and Fire Codes & Regulations.
c) To eliminate employee concerns regarding the quality of the potable water after fire pump tests/spurious operation.
d) To address and mitigate environmental concerns associated with the existing Sewage Treatment Plant (STP).
e) To design and install water (domestic and fire) and sanitary sewer distribution systems to the proposed new facilities for Darlington Refurbishment and the Campus Plan.

The existing water supply line was originally installed for the construction phase of the station. It was not replaced and has deteriorated and represents a single point of vulnerability.

The existing Sewage Treatment Plant (STP) requires extensive maintenance and care for its continued operation and compliance with applicable regulations. The capacity of the plant is not adequate to meet the demand of the station refurbishment project.

| $000's (incl contingency) | Type | LTD Dec 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Currently Released | Develop | 265 | 3,590 | 145 | | | | | | 4,000 |
| Adj to Current Release | Adjustments | (85) | (2,503) | (145) | | | | | | **(2,733)** |
| Requested Now | Partial | | 821 | 8,964 | 9,248 | - | - | | | **19,033** |
| Future Funding Req'd | Full | | | | 7,649 | 7,486 | 565 | | | **15,700** |
| **Total Project Costs** | | **180** | **1,908** | **8,964** | **16,897** | **7,486** | **565** | **-** | **-** | **36,000** |
| Non Project Costs | | | | | | - | | | | - |
| Grand Total | | 180 | 1,908 | 8,964 | 16,897 | 7,486 | 565 | - | - | 36,000 |

| | | | | |
|---|---|---|---|---|
| **Investment Type**<br>**Sustaining** | **Class**<br>**Capital** | **NPV**<br>**(25,596)** | **IRR**<br>**N/A** | **Discounted Payback**<br>**N/A** |

Submitted By: (Date)

July 22, 2011

Dietmar Reiner
SVP, Nuclear Refurbishment

Reviewed By: (Date)

for

July 28/2011

Albert Sweetnam
EVP, Nuclear Projects

Financial Approval By: (Date)

August 2, 2011

Donn Hanbidge
SVP & Chief Financial Officer

**(OAR Element 1.1 Project in Budget)**
Line Approval By: (Date)

2011-08-08

Tom Mitchell
President and Chief Executive Officer

## 2/ BACKGROUND & ISSUES:

In preparation for the continued operation of the Darlington Nuclear Generating Station (DNGS) for an additional 25 to 30 years, the Domestic Water and Sewage Treatment Project was initiated based on the finding of gaps between the current domestic & fire water and sewage system condition and future incremental requirements. The scope and estimate of this project is a combination of two separately approved charters (D-PCH-72700-10002-R001-Install and tie-in water and sewer systems to municipalities and D-PCH-72700-10003-R000-Install distribution systems to proposed Refurbishment and Campus Plan facilities).

The needs for meeting the above requirements are further explained in the sections below:

### 2.1 Domestic/Fire Water Supply

The DNGS domestic & fire water line is supplied from the Durham Region Municipal Water System. Presently, a single pipe system supplies both domestic water requirements for powerhouse and site buildings, as well as fire protection water for all site buildings, via a common buried water distribution system. The condition of the existing piping is deteriorating. The current domestic/fire water system peak flow rate capacity is not adequate to meet the estimated demand for major programs such as refurbishment due to the fact that a large number of people will be working on many projects and refurbishment activities on site during that program. Also, there will be some new campus plan and refurbishment facilities during the next decade which would require additional water and sewage system capacity.

A series of reported events resulting from the continued use of the temporary water storage bladders and fire pump raised concerns about the site domestic water system. The source of the concerns was found to be the temporary water storage bladders, which were isolated in 1997, after which the water they contained was not considered to be potable. These bladders are still in service for fire protection purposes only. On several occasions, the fire pump has started unexpectedly due to mechanical problems or pressure transients. This results in water from the bladders entering the active part of the domestic water system. Station procedures require that the domestic water system be quarantined, flushed, and analyzed following operation of the fire water booster pump and for in service declaration. This represents a significant disruption to normal station operation and a considerable cost to the corporation. The cost could be significantly high, should a spurious start of fire water pump occur during an outage. The domestic Water Pump House Compliance issues relate to deficiencies in the fire related separations, lack of sprinkler and ventilation systems, less than adequate diesel tank support structure and spill control, electrical system deficiencies including lighting transformers, power supplies, fire panel and pump controls. The only way to prevent such reported events and to address the fire code compliance issues is to eliminate the need for the Domestic Water Pump House and bladders. As part of this project, these bladders will be removed from service.

As part of the Darlington Refurbishment and Campus Plan projects, a number of facilities are going to be constructed on site as per the campus plan initiative. These new facilities will require water (domestic and fire) system connections to the water main.

### 2.2 Sanitary Sewer Upgrades

#### 2.2.1 Sewage Treatment Capacity:

The current sewage system average flow rate and treatment capacity is not adequate to meet the estimated demand for major programs such as refurbishment due to the fact that a large number of people will be working on many projects and refurbishment activities on site during that program. Also, there will be some new campus plan and refurbishment facilities during the next decade which would require additional sewage system capacity.

The proposed refurbishment and campus plan facilities to be built as per the campus plan will require connections of sanitary sewer lines to the sewer main.

#### 2.2.2 Environmental Concerns:

In 2007 there was a series of reported events resulting from release of unmonitored sewage due to equipment failure in the Sewage Treatment Plant (STP).

The Federal Government has Proposed Wastewater Systems Effluent Regulations under the Fisheries Act to establish national effluent quality standards. The existing STP would not be able to meet the new regulations that are being proposed..

### 2.2.3 De-commissioning and removal of existing STP:

Once the Sanitary Sewer Systems are re-directed to the municipality, the existing STP will be de-commissioned and removed. This will eliminate the above stated environmental concerns, as well as eliminate asset maintenance and operating costs.

## 2.3 Conceptual Study and Preliminary Engineering

### 2.3.1: Conceptual Study -Complete

In October of 2009, an external consulting company was retained to assess DNGS need and find acceptable water and sewage solutions for the site. The background information on the systems, including reports and drawings, were reviewed and servicing options were developed based on internal meetings, analysis and discussions.

The water and sewage flow rate demands were determined for the site under steady state and projected peak demand conditions.

The conceptual report focused on providing secure water supply and sanitary services for DNGS from existing Regional Services. The Region has recently installed the piping extensions and tie-ins points for these new systems at planned locations on Holt Road and Solina Road.

### 2.3.2 Preliminary Engineering – In Progress

In December 2010 the engineering consultant undertook the preliminary engineering of the project. The water demands for domestic and fire use were confirmed and detail Water Supply System/Network Analysis was prepared to finalize the sizing and routing of the piping system. Other preliminary engineering activities and deliverables were as follows:

- Conduct topographical surveys
- Scanning for borehole drilling
- Borehole Drilling (currently in progress) for soil sampling
- Finalize the plan and profile of all the piping systems
- Determine the major equipment and technical specifications
- Complete the Design Requirements for both water and sewer systems
- Liaise with local authorities and stakeholder for planning the Permits and Approvals
- Prepare a release quality estimate for procurement and construction of water and sewer mains

## 2.4 Ongoing Operational Costs

At this stage, it is estimated that cost savings from abandoning the operation of the Sewage Treatment Plant, Water Bladders and the Chlorination systems, partially offset by costs of municipal water and sewage treatment services, are about $100 000 per year. These cost saving estimates will be refined for the Full Release.

## 3/ ALTERNATIVES & ECONOMIC ANALYSIS:

| $ 000's | Base Case | Alt 1 (Recommended) | | Alt 2 | Alt 3 | Alt 4 | Alt 5 |
|---|---|---|---|---|---|---|---|
| | | Full Cost | Incremental Cost | Delay for two years | Build Site Specific Systems | Do Less | |
| **Revenue** | | | | | | | |
| Base OM&A | 0 | 4,522 | 4,522 | 4,222 | | 4,563 | |
| Outage OM&A | | | | | | | |
| Project OM&A | | | | | | | |
| **Total OM&A** | 0 | 4,522 | 4,522 | 4,222 | 0 | 4,563 | 0 |
| **Capital** | 0 | (32,842) | (32,012) | (34,897) | | (26,302) | |
| **Present Value (PV)** | 0 | (25,596) | (24,869) | (23,767) | Not Calculated | (20,784) | |
| **Net Present Value (NPV)** | **N/A** | **(25,596)** | **(24,869)** | **(23,767)** | **#VALUE!** | **(20,784)** | |
| Internal Rate of Return (IRR) % | N/A | N/A | N/A | N/A | N/A | N/A | |
| Discounted Payback (Yrs) | N/A | N/A | N/A | N/A | N/A | N/A | |

Note: The estimated cost savings and removal costs are included the economic analysis as Base OM&A.

**Base Case:** × *Not Recommended* - **Do Nothing**

To do nothing is not recommended because this alternative will not allow DNGS to meet the domestic/fire water and sewage treatment demand for refurbishment work and continued station operation. This alternative has not been estimated and is used as a basis to evaluate the incremental cost of other alternatives.

**Alternative 1:** ✓ *Recommended* - **Install new domestic and fire water mains and redirect the sanitary sewage system to the Municipality**

Installation of domestic water and fire water lines from the municipality of Oshawa at Osborne Road and a new fire water line from the municipality of Bowmanville on Holt Road just south of Highway 401. Install tie-in points in strategic locations for supply of water to various station facilities.

Bypass the domestic water supply to the existing pump house equipment, complemented by the installation of booster pumping systems to maintain required pressures in the site buildings. This will allow the existing bladders, fire pump and chlorination equipment to be removed from the water system which will reduce maintenance and operating costs, simplify the functionality of the system and improve the water quality, thus eliminating employee concerns.

This alternative includes the installation of a sanitary sewer line from the station to the Courtice Water Pollution Control Plant along with the construction of a new pumping station. This would allow OPG to send sewage directly to the municipality and de-commission the existing deteriorating Sewage Treatment Plant.

Installation of water and sewer distribution lines and tie-in points to proposed Refurbishment and Campus Plan facilities.

The project boundaries for the domestic/fire water supply will be from the municipality tie-ins points to the station inlet flange in the existing Pump-house. The project boundaries for the sanitary sewer system discharge will be from a new Lift Station at the west of the existing Project Office to the municipality tie-ins point. The systems conditions and the documentation outside these boundaries are not included in the scope of this project.

**Alternative 2:** × *Not Recommended* - **Delay for 2 years**

This is not recommended since this project is on critical path to support the refurbishment project. Water and Sewer are basic needs for the personnel working on site during the refurbishment project. Water and Sewer infrastructure need to be developed before any proposed facilities are to be built. Delaying the project will impact the DNGS Refurbishment.

**Alternative 3 :** × *Not Recommended* - **Build site specific water supply and sanitary treatment systems with the latest technology**

This is not recommended since this alternative would be significantly more expensive both in terms of capital and incremental operating and maintenance costs over the life of the plant. An order of magnitude estimate for these facilities is in the order of $150M capital and about $200M of incremental OM&A for the life of the station (PV has not been calculated for this option).

**Alternative 4:** × *Not Recommended* - **Do Less (only water supply and Sewer discharge, not distribution).**

This is not recommended since entire scope of this project is the required infrastructure for the station refurbishment initiative and continued operation of the station to end of life.

## 4/ THE PROPOSAL

Approval of this release of funds will allow the project to complete the following tasks:

- Complete the design of water main connections from Holt Rd and Solina Rd to the station inlet.
- Complete the design of the sanitary sewer main from a new force main (west of Building 116 – Project Office) to the Solina Rd tie-in point.
- Complete the design of water and sanitary sewer connections to the Campus Plan and Refurbishment facilities.
- Supply and construction of sanitary sewer mains.
- Supply and construction of water mains
- Obtain a full release BCS for the balance of the project.

**Project Execution Strategy for Water and Sewer Mains**

The preliminary engineering of the project is in progress and will be completed by September 2011. The project will complete the design, necessary approvals and permits for the Holt Road water main first. This is a part of the project base scope but will be done as first priority due to concerns regarding the condition and the reliability of the existing, and the only, 200mm domestic and fire water supply line to the station as well as meeting Darlington New Nuclear Project's (DNNP) request for vacating the proposed property for the new build by May 2012 in alignment with its contracting strategies. This priority setting will not have a negative impact on the project cost and schedule. Once abandoned, the existing line will be removed by the DNNP's site preparation program.

The design and start of the construction for the sewer system will be concurrent with the Holt Rd water main. The construction of the Solina Rd water main will start once the Holt Rd water main is in service.

**Future release of funds will provide for the following:**

- Procurement and construction of the water and sewer distribution systems and tie-in points to the new Refurbishment support buildings and Campus Plan facilities,
- De-commissioning and removal of the abandoned systems such as Pumphouse, Water Bladders with associated Chlorination systems and Sewage Treatment Plant.
- Potential installation of new fire booster pumps for some large buildings.

## 5/ QUALITATIVE FACTORS

The qualitative factors resulting from this project are:

- Eliminate employee concerns regarding of domestic water for staff consumption
- Provide redundancy in supply of domestic and fire water to the station from the municipality.

## 6/ RISKS ANALYSIS (See Attachment D for details)

| Low<br>1 to 3 | Medium<br>4 to 9 | [illegible] | | | | |
|---|---|---|---|---|---|---|
| | | Impact | | | | |
| | | 1 | 2 | 3 | 4 | 5 |
| Probability | 5 | 5 | 10 | 15 | 20 | 25 |
| | 4 | 4 | 8 | 12 | 16 | 20 |
| | 3 | 3 | 6 | 9 | 12 | 15 |
| | 2 | 2 | 4 | 6 | 8 | 10 |
| | 1 | 1 | 2 | 3 | 4 | 5 |

| Risk Description | Mitigating Activities | Mitigation | Finance | Schedule | Quality | Corporate Reputation | Regulatory | Health & Safety | Environmental | Nuclear Safety | Risk Rating (1 to 25) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Potential environmental requirements/impacts may result in higher cost and schedule complaints from public using the environmentally sensitive areas, and potential delay to permits. | Project plans have been communicated to the local authorities and the environmentally sensitive areas have been identified.<br>The Environmental Impact Statement will establish necessary mitigating measures for any potential risk. Adjustments have been made to the base cost and schedule. | Before | 15 | 20 | 0 | 10 | 10 | 0 | 0 | 0 | 25 |
| | | After | 3 | 9 | 0 | 3 | 3 | 0 | 0 | 0 | 9 |
| Interference with the Campus plan proposed facilities.<br>Additional water flow capacity requirement may arise. | The water flow demand is based on: historical use, previous studies based on fixtures, current and future station population for refurbishment, maintenance and normal operations. Modification Design requirements developed and approved. | Before | 12 | 16 | 12 | 0 | 0 | 0 | 0 | 0 | 16 |
| | | After | 2 | 6 | 4 | 0 | 0 | 0 | 0 | 0 | 6 |
| Elevation changes for gravity flow/pressure could cause redesign and rerouting of piping lines. | Flow conditions (rate and pressure) will be modeled by engineering and provisions will be made in the design to ensure adequate flow rate and pressure at the inlet to the station. | Before | 12 | 25 | 12 | 0 | 0 | 0 | 0 | 0 | 20 |
| | | After | 6 | 9 | 3 | 0 | 0 | 0 | 0 | 0 | 9 |
| Pressure differentials between Oshawa and Bowmanville water mains. | Engineering consultant has performed nodal analysis and will provide for the pressure balancing devices in the design | Before | 10 | 15 | 5 | 0 | 5 | 0 | 0 | 0 | 15 |
| | | After | 2 | 2 | 1 | 0 | 1 | 0 | 0 | 0 | 2 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Productivity losses due to weather and alternate construction methods due to restrictive environmental conditions. | The project will monitor this closely with the PC company and will deal with upcoming issues in a case by case method. | **Before** | 15 | 20 | 0 | 0 | [illegible] | 0 | 0 | 0 | 20 |
| | | **After** | 5 | 5 | 0 | 0 | 5 | 0 | 0 | 0 | 5 |
| Discovery above and below ground work due to land and environmental conditions during construction. | The risk will be transferred to the PC company with a fixed price contract. Specific Contingency of [redacted] has been requested in the BCS for this risk. | **Before** | 9 | 9 | 0 | 3 | 3 | 0 | 0 | 0 | 9 |
| | | **After** | 2 | 4 | 0 | 2 | 2 | 0 | 0 | 0 | 4 |

**Darlington Water and Sewer Project 10 - 73802 (Capital)**
**Partial Release Business Case Summary NK38 - BCS - 72700 - 10008 - R000**

## 7/ POST IMPLEMENTATION REVIEW

| Type of PIR: | Targeted Final AFS Date: | Targeted PIR Approval Date | PIR Responsibility (Sponsor Title) |
|---|---|---|---|
| **Simplified** | **27-Nov-14** | 27-May-15 | Mgr Nuclear E Facil |

| | Measurable Parameter | Current Baseline | Targeted Result | How will it be measured? | Who will measure Person / Group? |
|---|---|---|---|---|---|
| 1. | Domestic water | One 200 mm Line from Durham Region | One 300 mm line from Durham Region | New line in service/project AFS | Nuclear East Facilities |
| 2. | Fire water | Water Bladders and Diesel Fire Pump | Two new fire water mains (400mm) from two townships. | New lines in service/project AFS | Nuclear East Facilities |
| 3.. | Fire water pressure | 586 kPa | 586 kPA | Pressure Gage | Nuclear East Facilities |
| 4. | Sewage Treatment Plant | Operating | Abandoned | Flow of sanitary sewer to the municipality/project AFS | Nuclear East Facilities |
| 5. | Fire Pumphouse | Operating | Abandoned | Pumphouse by-passed/part of project AFS | Nuclear East Facilities |
| 6. | Water Bladders | Operating | Abandoned | Bladders by-passed/part of project AFS | Nuclear East Facilities |

## APPENDIX "A' GLOSSARY (acronyms, codes, technical terms)

| | |
|---|---|
| **AFS** | Available for Service |
| **Bladders** | reservoirs or bags for water supply. |
| **BOE** | Basis Of Estimate. |
| **BU** | Business Unit. |
| **CBDO** | Carbonaceous Biochemical Oxygen Demand. |
| **CNR** | Canadian National Railway. |
| **CWPCP** | Courtice Water Pollution and Control Plant. |
| **DNGS** | Darlington Nuclear Generating Station |
| **DNNP** | Darlington New Nuclear Project |
| **L/S** | Liter Per Second. |
| **MOE** | Ministry of Environment. |
| **RFP** | Request For Proposal. |
| **SCR** | Station Condition Record. |
| **SOW** | Scope Of Work. |
| **SPS** | Sanitary Pumping Station. |
| **STP** | Sewage Treatment Plant. |
| **TRC** | Total Residual Chlorine |
| **VBO** | Vacuum Building Outage. |

## APPENDIX "B"

## Comparison of Total Project Estimates

| $ 000's | | This Appendix compares the Total Project Estimate for each BCS | | | | | | | | | | Total Project Est |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | *Total Project Estimate* (by Year incl Contingency) | | | | | | | | | |
| BCS Type | Class | Mth | Yr | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Later | |
| Developmental | Capital | Jul | 2010 | 265 | 3,590 | 11,542 | 9,980 | 8,380 | 4,800 | 1,443 | | 40,000 |
| Partial | Capital | Aug | 2011 | 180 | 1,908 | 8,964 | 16,897 | 7,486 | 565 | | | 36,000 |
| | | | | | | | | | | | | 0 |
| | | | | | | | | | | | | 0 |
| | | | | | | | | | | | | 0 |
| | | | | | | | | | | | | 0 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LTD Spent | Capital | May | 2011 | 180 | 830 | | | | | | | 1,010 |
| LTD Spent | | | | | | | | | | | | 0 |
| LTD Spent | | | | | | | | | | | | 0 |

**Comments:**

See comments in Project Variance Analysis.

## Darlington Water and Sewer Project 10 - 73802 (Capital)
## Partial Release Business Case Summary NK38 - BCS - 72700 - 10008 - R000

## APPENDIX "C"

## FINANCIAL MODEL – ASSUMPTIONS

### Financial Assumptions:

| | | | | | |
|---|---|---|---|---|---|
| Discount Rate: | 7% | Cost Escalation (Yr) | 3% | SR&D Opportunity | No |
| Progress Payments | Yes | Foreign Currency | No | Retainer Fee | No |
| Depreciation Rate (Capital) | Blgs Oth Structures 4% | PST | No | Interest Rate (Capital) | 6% |
| Revenue Rate | Nuclear Est | Leasing | No | Indexed Priced Contract | No |

**Comments:**

### Project Cost Estimate:

| | | | | | |
|---|---|---|---|---|---|
| Design Complete: | Up to ~ 15% | Fixed Price Contract | Yes | 3rd Party Estimate | Yes |
| Quality of Estimate | Release +15% to -10% | OPEX used | Yes | Lessons Learned | Yes |
| Similar Projects | Yes | Budgetary Quote | No | First Unit Actual Used | N/A |
| Firm Vendor Proposal | No | Cost Sharing | No | Competitive Bid | Yes |
| Reviewed by Sponsor | Yes | Fee for Service | No | Contracts in place | No |

**Comments:**

### Project Cost Estimate Assumptions:

1. The cost estimate for detailed engineering is based on a fixed price contract with an engineering company.
2. The estimate for procurement and construction of the project is based on the cost report provided by the company who completed the preliminary engineering and is experienced with this type of work in Durham Region. Allowances for environmental mitigation and remediation as well as provisions for productivity loss due to working in busy areas of the site and outdoor weather conditions are included in the estimate.
3. Specific Contingency of [redacted] is allocated for potential discovery work including aboveground and underground findings.
4. The project will retain the services of a Procurement and Construction contractor (PC) - on fixed price basis - for the supply and construction of the project. OPG's role in this contract will be the Owner Only as per OHSA.
5. General Contingency for the partial release is [redacted]% according to the contingency calculation tool.
6. General Contingency for future release is [redacted]% according to the contingency calculation tool.
7. On-going operation and maintenance cost for the new systems, estimated at $0.6 Million per year, represents a cost saving of $0.1 Million and is included in the NPV analysis.
8. Decommissioning and removal cost has been estimated at $2.1 Million and is included in the financial evaluations.
9. The projects responsible for construction of the proposed Refurbishment and Campus Plan facilities will be responsible to install connections to the tie-in points that this project will provide for the said facilities in a close proximity of the proposed facilities as per the latest plan at time of detailed design.

### Rationale for Capital Cost Classification:

Replacement of existing domestic and fire water supplies with higher capacity supplies that support extension of the life of Darlington facilities as well as the addition of a new sewage system to replace the life-expired site Sewage Treatment Plant.

**Generation Plan Assumptions:**

| Station | Unit | EOL or Refurb | MW | Planned Outages for Project Work | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Pickering A | 1 | Jun-20 | 515 | N/A | | | | | | |
| | 4 | Jun-20 | 515 | N/A | | | | | | |
| Pickering B | 5 | Nov-18 | 516 | N/A | | | | | | |
| | 6 | Nov-18 | 516 | N/A | | | | | | |
| | 7 | Jun-20 | 516 | N/A | | | | | | |
| | 8 | Jun-20 | 516 | N/A | | | | | | |
| Darlington | 1 | Sep-16 | 878 | N/A | | | | | | |
| | 2 | Feb-18 | 878 | N/A | | | | | | |
| | 3 | Sep-19 | 878 | N/A | | | | | | |
| | 4 | Jan-21 | 878 | N/A | | | | | | |

**Comments:**

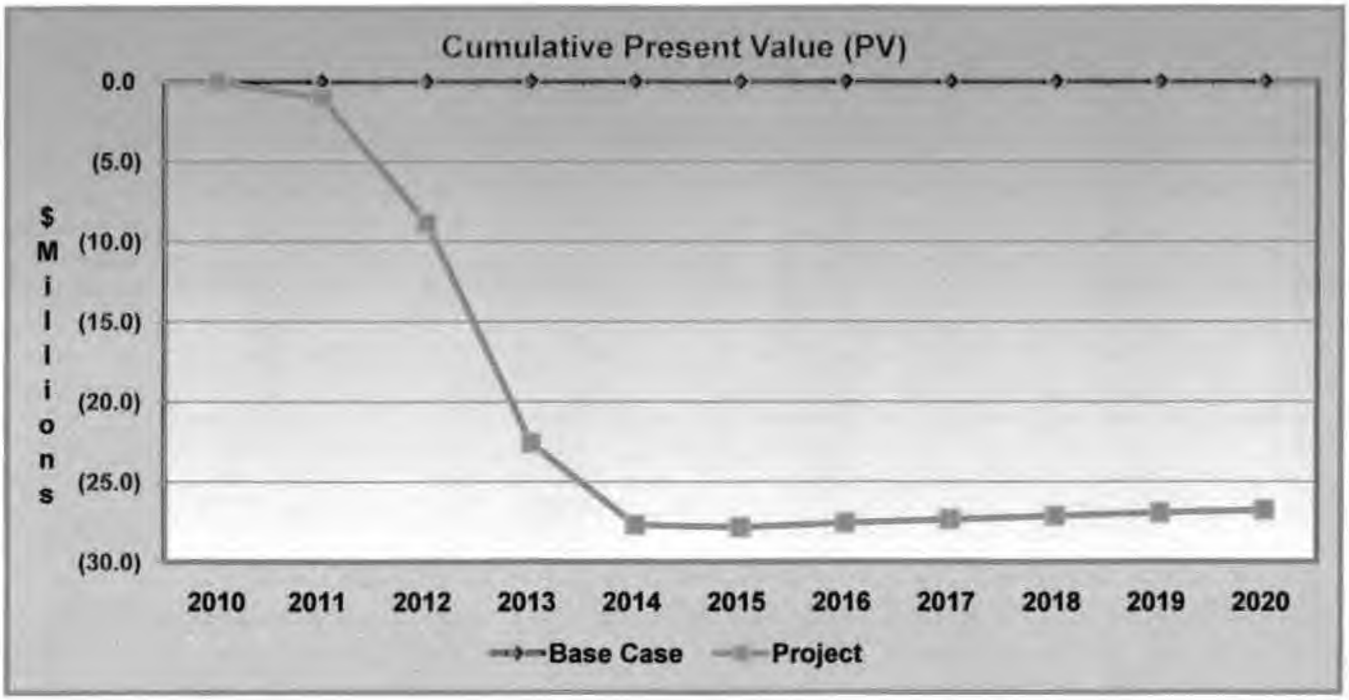
## APPENDIX "D"

## FINANCIAL MODEL – ASSUMPTIONS

### Impact on Operations

Comments: The project will not require unit outages,therefore,no impact on production of electricity.

### Cumulative Present Value Graph:



**APPENDIX "E"** ***PROJECT DELIVERABLES***

| Item | Description | Deliverable | Cost ($000's) |
|---|---|---|---|
| 1 | Detail design water and sewer systems | From Holt Rd & Solina Rd to station inlet | [redacted] |
| | | From new force main to Solina Rd tie-in point | [redacted] |
| | | Connections to Campus Plan and Refurbishment facilities | [redacted] |
| 2 | Sanitary sewer main to municipality | Installation of Sewer Main | [redacted] |
| | | | [redacted] |
| 3 | Water main connections | Installation of Water Main | [redacted] |
| | | | |
| 4 | Project Management | SOWs | 50 |
| | | RFPs | 50 |
| | | Procurement and Construction contract | **25** |
| | | Full Release BCS | 25 |
| | | Project Execution Plan | 10 |
| | | P6 Schedule | **10** |
| | | Project coordination and reporting | 513 |
| 5 | Installation support | Contract Administration | 300 |
| | | Quality Surveillance | **50** |
| | | | |
| 6 | Contingencies | General | [redacted] |
| | | Specific | [redacted] |
| | | | [redacted] |
| 7 | Interest | Interest | [redacted] |
| | | | |
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| | | | |
| **Total** | | | **19,033** |

# Darlington Water and Sewer Project 10 - 73802 (Capital)
# Partial Release Business Case Summary NK38 - BCS - 72700 - 10008 - R000

## ATTACHMENT "A" PROJECT COST SUMMARY

| $ 000's Capital | | LTD Dec 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Accounting Basis | Project Mgmnt & Support | 156 | 305 | 355 | 355 | 335 | 185 | | | **1,691** |
| | Engineering | 24 | 830 | 662 | 462 | 475 | 175 | | | **2,628** |
| | Procurement | | | | | | | | | - |
| | Construction | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Other | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | | | | | | | | | - |
| | | | | | | | | | | - |
| | | | | | | | | | | - |
| | Interest (Capital Project) | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Project Costs** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | General Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Specific Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Project Costs** | **180** | **1,908** | **8,964** | **16,897** | **7,486** | **565** | **-** | **-** | **36,000** |

| $ 000's Capital | | | LTD Dec 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Funding Basis | **Current Release** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | **265** | **3,590** | **145** | **-** | **-** | **-** | **-** | **-** | **4,000** |
| | **Adj to Current Release** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | (85) | (2,503) | (145) | - | - | - | - | - | **(2,733)** |
| | **This Release** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | - | 821 | 8,964 | 9,248 | - | - | - | - | **19,033** |
| | **TTD Released** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | **180** | **1,908** | **8,964** | **9,248** | **-** | **-** | **-** | **-** | **20,300** |
| | **Future Releases** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | **-** | **-** | **-** | **7,649** | **7,486** | **565** | **-** | **-** | **15,700** |
| | **Project Funding** | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Contingency Funding** | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Total Funding** | | **180** | **1,908** | **8,964** | **16,897** | **7,486** | **565** | **-** | **-** | **36,000** |
| Budget | **2011 - 2015 Business Plan** | | 971 | 3,390 | 7,602 | 5,046 | 5,152 | 5,255 | 5,203 | 0 | **32,619** |
| | **Variance to Budget** | | (791) | (1,724) | (214) | **8,425** | **85** | (4,835) | (5,203) | **0** | (4,257) |
| Other | **Removal Costs (above)** | | | | | | 2,122 | | | | **2,122** |
| | **Inventory W / O** | | | | | | | | | | - |
| | **Spare Parts in Invent** | | | | | | | | | | - |

**Reviewed by:** **(Date)**

July 6, 2011

Morad Solaimani
Project Manager

**Approved by:** **(Date)**

July 7 - 2011

Carm Agosta
Manager

## Darlington Water and Sewer Project 10 - 73802 (Capital)
## Partial Release Business Case Summary NK38 - BCS - 72700 - 10008 - R000

**ATTACHMENT "B"** **PROJECT VARIANCE ANALYSIS**

| | $ 000's Capital | LTD May 2011 | Total Project Last BCS Jul 2010 | Total Project This BCS Aug 2011 | Variance | Comments |
|---|---|---|---|---|---|---|
| Scores Basis | Project Mgmnt & Support | 583 | 3,940 | 1,691 | (2,249) | Note 1 |
| | Engineering | [redacted] | [redacted] | [redacted] | [redacted] | Note 2 |
| | Procurement | | [redacted] | [redacted] | [redacted] | Note 3 |
| | Construction | | [redacted] | [redacted] | [redacted] | Note 3 |
| | Other | | [redacted] | [redacted] | [redacted] | Note 4 |
| | | | | | - | |
| | | | | | - | |
| | | | | | - | |
| | | | | | - | |
| | Interest (Capital Project Only) | [redacted] | [redacted] | [redacted] | [redacted] | Note 5 |
| | **Project Costs (Scores Basis)** | [redacted] | [redacted] | [redacted] | [redacted] | |
| | General Contingency | [redacted] | [redacted] | [redacted] | [redacted] | Note 6 |
| | Specific Contingency | [redacted] | [redacted] | [redacted] | [redacted] | Note 6 |
| | **Project Costs ( Scores Basis)** | **994** | **40,000** | **36,000** | **(4,000)** | |

| | | | | | | |
|---|---|---|---|---|---|---|
| Other | **Removal Costs included above** | | **1,460** | **2,122** | 662 | Note 7 |
| | **Inventory to be written off** | | | | - | |
| | **Spare Parts in Inventory** | | | | - | |

Note 1 Lower OPG resources required to manage a fixed price Owner Only procurement and construction contract.

Note 2 Engineering included OPG and contractor resources which have now been refined. .

Note 3 Materials and construction have been refined and include as a single contract. Contract Management office was included in PM costs

Note 4 Support of other OPG departments

Note 5 Reduced due to multiple in-service declarations.

Note 6 Quality of estimate is improved. Added specific contingency to mitigate environmental discovery issues.

Note 7 Refined scope of work for removals

**Darlington Water and Sewer Project 10 - 73802 (Capital)**
**Partial Release Business Case Summary NK38 - BCS - 72700 - 10008 - R000**

## ATTACHMENT "C" SCHEDULE

### Key Milestones

| Completion Date | Description |
|---|---|
| 15-Sep-11 | Partial BCS OAR Approved |
| 21-Sep-11 | Design Contract Awarded |
| 24-Nov-11 | Supply and Installation Contract Awarded for Holt Road Watermain |
| 27-Jan-12 | Design Complete for Holt Road Watermain |
| 17-Feb-12 | Start of Installation Holt Road Watermain |
| 12-Apr-12 | Design Complete for Sewer and Solina Rd Watermains |
| 17-May-12 | Supply and Installation Contract Awarded for Sewer and Solina Rd Watermains |
| 31-May-12 | Partial AFS Holt Road Watermain |
| 18-Jun-12 | Start of Installation of Sewer and Solina Rd Watermains |
| 30-Oct-12 | Design complete for Distribution systems |
| 23-May-13 | Full Release BCS OAR Approved |
| 25-Jul-13 | Partial AFS of Sewer and Solina Rd Watermains |

A Project Execution Plan (PEP) will be approved by 15-Mar-12

### In Service Declarations: (Capital only)

| Date | Description | $000's (Total = Project Cost incl contg) | % In Service (= 100%) |
|---|---|---|---|
| 31-May-12 | Partial AFS for Holt Road water main | 5,000 | 15% |
| 25-Jul-13 | Partial AFS Main Headers for Sewer, Domestic and Fire water | 14,200 | 38% |
| 24-Apr-14 | Partial AFS Distribution lines for Sewer, Domestic and Fire water | 11,000 | 30% |
| 28-Aug-14 | Partial AFS for decommissioning and removal of some water and sewer systems | 4,000 | 12% |
| 27-Nov-14 | Final AFS for sewer, and domestic water system upgrades | 1,800 | 5 % |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |

**Comments:**

## Darlington Water and Sewer Project 10 - 73802 (Capital)
## Partial Release Business Case Summary NK38 - BCS - 72700 - 10008 - R000

### Risk Probabilities Chart

| Likelihood | Improbable | Unlikely | Possible | Likely | Probable |
|---|---|---|---|---|---|
| Probability | <= 1 in 100 | About 1 in 100 | About 1 in 10 | About 1 in 5 | >= 3 in 4 |
| Rank | 1 | 2 | 3 | 4 | 5 |

### Risk Impact Chart

| Impact Rating | Financial | Project Schedule 12 month | Quality | Corporate Reputation | Regulatory / Legal | Health & Safety | Environment | Nuclear Safety |
|---|---|---|---|---|---|---|---|---|
| 5 | >80% of Total Project $ | > 90 day delay | Significant, unacceptable non-conformance requiring extensive rework | National and international adverse coverage or impacts | Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges OR Potential loss of operating licenses | Potential for fatality(s) | Spill or release causing immediate and extended impact with off-site impacts, e.g.:Clean-up costs > $15MCat. A spill (>55 pts) | Loss or serious degradation of a safety system |
| 4 | 30% - 80% of Total Project $ | 30 - 90 day delay | Unacceptable non-conformance requiring some rework, but not major | Long-term local or national impact | Legislative non-compliance with potential for fines, charges, and damages ORMajor degradation of reputation with regulatory bodies | Potential for life-threatening critical injury or permanent total disability, including occupational disease | Exceedances resulting in charges or Director's OrderCat. A spill (45 - 55 pts)Public complaints with OPG implications Explosion and/or major fire | Reduced effectiveness of a safety system |
| 3 | 15% - 30% of Total Project $ | 10 - 30 day delay | Non-conformance bordering design tolerances, potential to require rework | Major local impact or minor national impact.Minor local damage | Systematic non-compliance with potential for finesORPotential to cause strained relationship with regulator, increased surveillance and/or regulations | Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature | Cat. B spillsEmission in exceedance of regulatory or legal limitsField orders or AMP'sPublic complaints with OPG implicationsDanger to health, life, or property | Reduced effectiveness of redundant safety system components |
| 2 | 5% - 15% of Total Project $ | 3 - 10 day delay | Acceptable non-conformance, within design tolerances, no rework required | Complaints from local officials / politicians | Systematic non-compliance with impacts to project scheduleORPossibility of regulatory / legal implications | Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker. | Cat. C spills - reportableAdministrative infractionsPublic Complaints with plant level implications | Impact on a safety support or safety related system |
| 1 | <5% of Total Project $ | < 3 day delay | Minimal impact on qualityRoutine non conformance can be easily dispositioned | Complaints from local public | Isolated non-complianceORRoutine approval / notification | No medical attention beyond first aid, no impairment to worker or complete recovery of worker | Administrative, non-reportable eventsCat. C spills non-reportable and spills resulting from Acts of God | |

ONTARIOPOWER GENERATION

Records File Information:
See Guidance Section

OPG-FORM-0076-R003*

# Type 3 Business Case Summary

Final Security Classification of the BCS: **OPG Confidential**

To be used for investments/projects meeting Type 3 criteria in OPG-STD-0076.

**Executive Summary and Recommendations**

| | | | |
|---|---|---|---|
| **Project #:** | 16-31555 | **Title:** | D2O Storage and Drum Handling Project |
| **Phase:** | Execution | **Release:** | Partial |
| **Facility:** | Darlington | **Records File:** | N-BCS-00120.3-10018-R000 |
| **Class:** | Capital | **Investment Type:** | Value Enhancing |

**Project Overview**

**We recommend the release of $11,641 k ([redacted] base costs plus [redacted] contingency).**

The work to be completed under this release includes ordering of long lead materials, such as Nuclear Class III tanks and pumps, and the start of site preparation activities upon approval of the Darlington Refurbishment Environmental Assessment.

The project scope is to build a facility for the storage of 2,100 $m^3$ of $D_2O$ in tanks, including a drum cleaning, testing and handling area and consolidated office space for the Tritium Removal Facility (TRF) staff. The planned in service date is October 15, 2015. Of the 2,100 $m^3$ of $D_2O$ storage to be provided, 1,700 $m^3$ is mandatory support of core scope for Darlington Refurbishment (a value enhancing project). The appropriate alternative for this scope is the lowest cost feasible alternative. The remaining project scope provides needed $D_2O$ management operational improvements and is also value enhancing scope. The need for $D_2O$ management operational improvements had been approved earlier but was deferred in June 2009 to be consolidated with Refurbishment's need for $D_2O$ storage to achieve economies of scale.

This project is currently executing a full definition release of $15,689 k to complete scope definition, modification planning, and detailed engineering. This work will be completed by July 15, 2013 and includes Phase I of a three phase engineer, procure and construct (EPC) contract. OPG previously negotiated a performance target price for Phase I of the EPC contract, and a performance target price for the entire EPC contract. Shortly after approval of the full definition release, OPG successfully re-negotiated a fixed price for Phase I of the EPC contract. This reduces OPG's overall cost risk, while maintaining the same overall EPC performance target price. However, the contract change requires the Phase I price, previously approved under the full definition phase release, to be increased by $400k while the future Phase III target price, to be released later, will be reduced by $400k. This change is reflected in the cash flows for this project and approval for this change to the cash flows from the previously released full definition phase is being requested as part of this partial execution phase release business case.

This partial execution release is required in parallel to the full definition release to issue Phase II of the EPC contract in order to mitigate schedule completion risk. Total released for this project after approval of this BCS will be $30,930k, which includes LTD, currently released, requested now, and contingency. Contingency is broken out in Part G of this BCS.

**Project Cash Flows**

| k$ | LTD | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Future | Total |
|---|---|---|---|---|---|---|---|---|---|
| Currently Released | 3,034 | 7,413 | 8,842 | | | | | | 19,289 |
| Requested Now | - | 3,275 | 8,366 | | | | | | 11,641 |
| Future Required | - | | 21,574 | 40,880 | 14,667 | | | | 77,121 |
| **Total Project Cost** | 3,034 | 10,688 | 38,782 | 40,880 | 14,667 | | | | 108,051 |
| Ongoing Costs | - | | | | 348 | 638 | 663 | on-going OM&A | |
| **Grand Total** | 3,034 | 10,688 | 38,782 | 40,880 | 14,667 | | | | 108,051 |

| | | | |
|---|---|---|---|
| **Estimate Class:** | Class 2 | **Estimate at Completion:** | $84,128 k |
| **NPV:** | $67,100 k | **OAR Approval Amount:** | $108,051 k |

**Additional Information on Project Cash Flows (optional):**

Grand Total does not include on-going costs (OM&A).

**Approvals**

| | Signature | Comments | Date |
|---|---|---|---|
| This BCS represents the best option to meet the validated business need in a cost effective manner. | | | |
| **Recommended by:**<br>Albert Sweetnam<br>Project Sponsor | | | 2 August 12 |
| I concur with the business decision as documented in this BCS. | | | |
| **Finance Approval:**<br>Donn Hanbidge<br>Position per OPG-STD-0076 | | | Aug 2/12 |
| I confirm this project will address the business need, is of sufficient priority to proceed, and provides value for money. | | | |
| **Approved by:**<br>Tom Mitchell<br>Position per OAR, per OAR 1.1 | | | Aug 2/12 |

## Business Case Summary

**Part A: Business Need**

**Business Need:**

The scope of this project is to build a heavy water ($D_2O$) storage and drum handling facility to meet two mandates. The first mandate is for Refurbishment, and the second mandate is to implement operational improvements for heavy water management at Darlington and OPG's Tritium Removal Facility (TRF). This will be accomplished by increasing operational storage at DNGS, adding $D_2O$ drum handling, cleaning, testing, and storage capability, and consolidating offices for TRF staff. Executing this work together saves cost through economies of scale.

Additional $D_2O$ storage capacity is needed to support refurbishment of Darlington. The first unit refurbishment outage is scheduled to begin October 2016. To meet refurbishment needs, the new $D_2O$ Storage Facility at Darlington must be completed and fully operational at least six months before the earliest potential start of refurbishment. The in-service date for this facility of October 15, 2015 is one year before the planned start of the first unit refurbishment outage to mitigate the risk of an earlier start of refurbishment, and to perform refurbishment preparation activities.

During refurbishment, storage capacity is needed at the Darlington site for the heavy water from two reactors, or 1,500 $m^3$, because of overlapping unit outages. In addition, refurbishment requires 200 $m^3$ of storage to facilitate flushing and other support operations associated with the preparation of the Darlington units for refurbishment work. This 200 $m^3$ storage need must be met through additional capacity as the existing Darlington operational storage is required to support the operations of the units across the OPG fleet that remain in service during refurbishment. Therefore, the total additional $D_2O$ storage capacity required to support refurbishment is 1,700 $m^3$.

The second mandate to improve heavy water management in support of all OPG nuclear units is the result of a previously approved Operational Improvement project which was deferred to be merged with the refurbishment D20 storage project in order to achieve cost efficiencies. The three main components of the second mandate are as follows:

1. Additional 400 $m^3$ of permanent storage required to improve utilization of the Darlington TRF and mitigate threats to the achievement of OPG detritiation objectives (before, during and after Darlington refurbishment) due to current storage constraints. The increased storage will address the TRF feed and product storage bottleneck that is a significant challenge to the efficiency of the overall tritium removal process. As documented in internal reports, eliminating this bottleneck is required to maintain the units within the Operating Policies and Principles limits for tritium.

2. A new Drum Handling, Cleaning, Testing, and Storage Facility providing services to both Pickering and Darlington stations will centralize drum storage, and provide a means of long term cleaning and disposal of the current inventory of drums. Incident reports indicate that the current large backlog of drums has caused radiological and conventional safety concerns, injuries, and significant operational burden due to storing drums throughout the Heavy Water Management Building. The facility will also provide the ability to support any refurbishment activities requiring drum cleaning/disposal, and expedite commercial shipments.

3. New consolidated office space for TRF staff. Construction of the new $D_2O$ Storage Facility will require demolition of existing permanent office trailers, and new replacement office space for these operations staff is required. As well, there are currently numerous staff located in nonstandard offices throughout the TRF/HWMB. In addition, Strat III and IV managers will be relocated to the central offices, improving communication, oversight, and time in the field. There will also be increased efficiencies associated with consolidating the TRF operations, maintenance, and management team. The office requirements are for 9 staff, including 1 conference room.

The increased operational storage (400 $m^3$) is a key element and supports implementation of the TRF Life Extension Strategy because it allows the existing facility to operate more efficiently and effectively and therefore maintain adequate quantities of detritiated $D_2O$ to support the operating units. This support is required to maintain Darlington's operating units within the established regulatory limits for tritium for the extended life of Darlington station.

The improvements to the TRF and Darlington operations are summarized below:

- Improve tritium removal capability within OPG by providing scheduling flexibility and reducing detritiation management dependency on TRF availability
- Improve utilization efficiency of available TRF capacity by providing storage for high Curie input feed, thereby maximizing tritium removal
- Improve operational flexibility and ability to segregate different $D_2O$ streams to support Darlington operation and outage scenarios, such as unit, station containment, and vacuum building outages
- Eliminate the backlog of $D_2O$ in drums that needs to be processed through the $D_2O$ Cleanup System
- Allow OPG to pursue new business opportunities for heavy water upgrading/detritiation and isotope sales
- Rectify long standing problem of unconsolidated and nonstandard work locations with new offices
- Support life extension of the TRF until 2055, mitigating risk of a costly TRF refurbishment or new TRF construction

**Part B: Preferred Alternative**

**Description of Preferred Alternative: Build 2100 m3 of D2O Storage and a Drum Handling Facilty**

Construction of a new 2,100 $m^3$ $D_2O$ storage and drum handling facility is recommended because it is the lowest cost option that meets both the mandate to support Darlington Refurbishment and the need for OPG heavy water management operational improvements.

The major components of this option are as follows:

(a) Refurbishment: 1700 $m^3$ of storage
(b) Heavy Water Management Operational Improvements:
  - 400 $m^3$ of storage for improved TRF operations
  - Drum Handling, Cleaning and Testing Facility
  - TRF Staff Offices for 9 staff, including 1 conference room

For refurbishment to be successful, the new facility must provide sufficient heavy water storage at the Darlington site for the heavy water from two units prior to start of refurbishment, a requirement of the Darlington refurbishment project. This option meets this requirement. In addition, by increasing the operational storage, this option would enable more efficient utilization of the Darlington TRF and mitigate threats to the achievement of OPG detritiation objectives (before, during and after Darlington refurbishment) due to current $D_2O$ storage constraints. Lastly, this option facilitates the current TRF/Heavy Water Management Life Cycle Management plan to 2055, thus reducing the risk of requiring a costly refurbishment of the existing TRF, or construction of a new TRF facility.

An economic analysis was completed for this alternative showing an NPV of $67,100 k for the $D_2O$ operational improvements scope of work. The tank storage option for Refurbishment $D_2O$ storage was found to be the lowest cost feasible alternative.

The execution of this work will be divided into 3 Phases:

Phase I, June 2012 – July 2013
Detailed Design. This work is underway under the previously approved Full Definition Release.

Phase II, September 2012 – September 2013
Site Preparation and procurement of Long Lead materials. This work will be executed under a Partial Execution Release (this BCS). Site preparation includes activities such as demolition of existing truck dock and TRF trailers, relocation of existing and buried services, start of excavation, and miscellaneous civil substructures. The Darlington Refurbishment Environmental Assessment is a prerequisite for the Site Preparation work and is required to be completed by December 2012 in order to preserve the project schedule.

Phase III September 2013 – April 2016

Construction of facility and tie-in to existing station. This work will be executed under a Full Execution Release.

The project has negotiated a performance based target price for an engineer, procure, and construct (EPC) contract to complete this work. A portion of the performance target price for the whole project is a fixed price contract to complete Phase I, Detailed Engineering. The fixed price portion and the overall target price are the basis of the design and construction costs. The OPG costs are associated with the required nuclear oversight to mitigate schedule and quality risks to ensure timely completion of this prerequisite project for Darlington Refurbishment. A significant constraint on the project is that the project cannot start Phase II Site Preparation and Phase III construction until the Darlington Refurbishment Environmental Assessment has been approved.

The following are milestones that will be confirmed during execution of the Partial Execution Release BCS.

| | |
|---|---|
| EPC Phase III Installation Contract Awarded | 23-Sep-13 |
| Start of Installation | 16-Oct-13 |
| Final In-service Declaration Complete | 15-Oct-15 |
| Project Close-out Complete | 15-Apr-16 |

| **Deliverables:** | **Associated Milestones (if any):** | **Target Date:** |
|---|---|---|
| The following are deliverables committed to under both the Full Definition Release and Partial Execution Release. | | |
| Partial Execution BCS (Under previous release) | Partial Execution BCS Approved | 14-Sep-12 |
| Preliminary Design Complete (Under previous release) | Preliminary Design Complete | 29-Oct-12 |
| Award Phase II of EPC Contract (Under this BCS) | EPC Phase II Installation Contract Awarded | 15-Jan-13 |
| Award Long Lead Material Contracts (Under this BCS) | All Long Lead Time Materials Contracts Awarded | 28-Mar-13 |
| Detailed Design Packages (Under previous release) | Design Documents Approved and Issued | 15-Jul-13 |
| Full Execution BCS (Under this BCS) | Full Execution Release Approved | 16-Sep-13 |

## Part C: Other Alternatives

**Base Case: Status Quo – No Project**

The do nothing option is not viable and therefore has not been assessed because this option does not meet the Darlington Refurbishment mandate. Work must be undertaken to address the 1700 $m^3$ storage requirements to support refurbishment.

**Alternative 2: Build "drum warehouse" inside the Protected Area to store 1700 m3 of D2O for Refurbishment in drums, and build a smaller D2O Facility for the Operational Improvements**

This option for the Refurbishment $D_2O$ storage is not viable because of the impact to the refurbishment outage critical path. It has been determined that 2 months of round the clock drumming would be required to drain the primary heat transport (PHT) system and moderator in this fashion. As well, it would require 2 months of round the clock drum purging to re-fill the PHT system and moderator post-refurbishment. This would be required for each refurbished unit, with estimated total lost generation revenue of approximately $290,000 k (2012$ PV).

An estimated 7200 drums at a cost of $1000/drum would also be required to implement this option. This solution would still require a building with similar requirements of the proposed solution, and therefore would still result in the need to design, procure, and construct a new $D_2O$ facility. Thus this option does not avoid much of the cost associated with the preferred option. The station would also be required to address an increased environmental risk of $D_2O$ spills. Current incident reports indicate that the existing backlog of drums have caused radiological and conventional safety concerns, injuries, and significant operational burden.

An economic analysis was completed for the $D_2O$ operational improvements scope of work with an NPV of $59,900k.

**Alternative 3: Delay Work- Building 1700 m3 for Refurbishment now, and Operational Improvement portion 3 years later**

This option does not meet the operational improvement requirements in the short term and it will increase risk to the TRF Life Extension Strategy.

The Operational Improvement portion of this work was previously approved in 2006. However, it was deferred to be merged with the refurbishment D20 scope in order to achieve cost savings, estimated at $20 M to $30 M, by realising efficiencies of completing the two mandates together as one project. Completing two different projects and time periods eliminates any cost savings even after factoring in the time value of money. There is high demand for detritiation services particulary in the period 2016 – 2020 as a result of the need to detritiate Pickering units prior to shutdown and to detritiate the heavy water drained from the Darlington units during refurbishment.

An economic analysis was completed for the $D_2O$ operational improvements scope of work with an NPV of $64,200k.

**Alternative 4: Do Less – Build 1700 m3 of Storage for Refurbishment needs only**

This option does not meet the operational improvement requirements and it will jeopardize the TRF Life Extension Strategy, and increase OPG's risk of having to complete a costly refurbishment of the existing TRF or the construction of a new TRF to meet ongoing regulatory detritiation requirements for the Darlington moderator and primary heat transport system. There is high demand for detritiation services particulary in the period 2016 – 2020 as a result of the need to detritiate Pickering units prior to shutdown and to detritiate the heavy water drained from the Darlington units during refurbishment.

The 400 $m^3$ of incremental storage is required to improve the efficiency and effectiveness of the TRF operation. Optimization of the TRF is required to improve its overall ability to manage its $D_2O$ inventories to support continuous station operations before, during and after the refurbishment period.

During the refurbishment period the 1700 $m^3$ will be utilized to drain the units, and will have limited capability of increasing the TRF's reliability. It is currently anticipated that the 1500 $m^3$ of reactor grade storage, which will be surplus storage after Darlington refurbishment, will be available for the long term storage of $D_2O$ from OPG units. Therefore, the operational improvements are still required to improve the efficiency and effectiveness of the TRF operation and minimize threats to OPG's detritiation objectives from 2015 to 2055.

**Alternative 5: Build 2100 $m^3$ of $D_2O$ Storage outside the Protected Area**

This option is not recommended as it is not viable. This option requires additional regulatory approvals from the CNSC and Ministry of Environment which would result in a significant delay to the project that would not meet Refurbishment's schedule. $D_2O$ is classified as nuclear material due to the tritium concentrations, and as a result, building a new facility outside the protected area would require a new protected area to be zoned and then built. Although technically feasible, the additional costs and time required to secure all regulatory approvals (such as evaluation of impact to the exclusion and protected zones), re-zone land for creation of a new protected area, and connecting interfacing systems at the current Heavy Water Management Building would not meet the Darlington refurbishment program needs and would result in significant risk to delaying the start of refurbishment. As this option is not a viable alternative, a financial evaluation has not been completed for it.

**Part D: Project Cash Flows**

| k$ | LTD | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Future | Total |
|---|---|---|---|---|---|---|---|---|---|
| Currently Released | 3,034 | 7,413 | 8,842 | | | | | | 19,289 |
| Requested Now | - | 3,275 | 8,366 | | | | | | 11,641 |
| Future Required | - | | 21,574 | 40,880 | 14,667 | | | | 77,121 |
| **Total Project Cost** | 3,034 | 10,688 | 38,782 | 40,880 | 14,667 | | | | 108,051 |
| Ongoing Costs | - | | | | 348 | 637 | 663 | on going OMA | |
| **Grand Total** | 3,034 | 10,688 | 38,782 | 40,880 | 14,667 | | | | 108,051 |

| | | | | | |
|---|---|---|---|---|---|
| **Estimate Class:** | Class 2 | **Estimate at Completion:** | $84,128 k | **OAR Approval Amount:** | $108,051 k |

**Additional Information on Project Cash Flows (optional):**

Grand Total does not include on-going costs (OM&A).

**Part E: Financial Evaluation**

| k$ | Base Case | Preferred Alternative | Alternative 2 | Alternative 3 | Alternative 4 |
|---|---|---|---|---|---|
| **Project Cost** | N/A | 105,017 | 48,600 | 119,000 | 84,300 |
| **NPV (after tax)** | 0 | 67,100 | 59,900 | 64,200 | 0 |
| **Other (e.g., LUEC)** | | | | | |

**Summary of Financial Model Key Assumptions (see Guidance on this Type 3 BCS Form):**

1. Project Costs shown are incremental (going forward) costs.
2. NPV values are for the Heavy Water Management Operational Improvements scope of work.
3. The interest has been included in the total project cost above, but has not been included for the NPV evaluation.
4. Alternative 5 does not meet the business need and therefore is not evaluated.
5. Assumptions used to calculate the NPV include:
    1. Operational improvements result in more efficient utilization of the Darlington TRF and improved heavy water management (e.g. decreased impact from TRF outages, potential for 3rd party $D_2O$ sales, dose savings at OPG stations)
    2. Operational improvements reduces probability of refurbishing existing TRF, or construction of a new TRF facility due to ability to stock pile low curie $D_2O$
    3. Between 2 and 4 staff (depending on which alternative) are required to support operation of the new facility

**Part F: Qualitative Factors**

Other qualitative factors associated with this project are as follows:

Government Relations

- Reduce tritium emissions throughout Ontario through improved efficiency for the detritiation of OPG and Bruce Power $D_2O$ inventory
- Reduce risk of infringing on tritium emission regulatory limits
- Reduce risk of infringing on OPG's Operating Policies and Principles limits through maintenance of unit tritium levels in the moderator and primary heat transport below required limits

Customer Relations

- Increasing OPG's capability and flexibility to process $D_2O$ will improve customer relations by providing flexibility in meeting contractual obligations with Bruce Power for detritiation services and provide the ability to increase detritiation services to third parties.

Health and Safety

- Reduced tritium levels due to increased TRF efficiency will reduce worker dose
- Additional drum storage will improve housekeeping and reduce drum handling requirements, thereby reducing the related health and safety concerns
- Reduce operator work around and extra operation actions that are required to maneuver various grades of $D_2O$ into unconventional storage arrangements

**Part G: Risk Assessment**

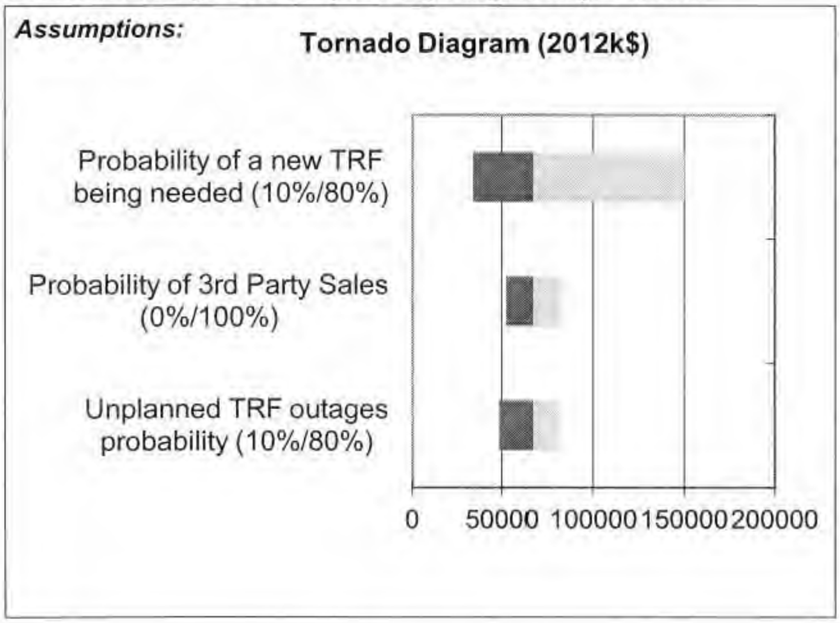
| Risk Class | Description of Risk | Risk Management Strategy | Post-Mitigation | |
|---|---|---|---|---|
| | | | Probability | Impact |
| Cost | Potential for tritum present in ground water and soil at preferred site, forcing design changes and/or additional soil/groundwater disposal costs. | Project 16-38940 is conducting an environmental site assessment, including the proposed location of the new facility. This will assess the situation and proposed mitigation options, including a contaminated soil disposal plan. The Mitigation and Disposal Plans will be incorporated into the Contract via the Change Management process as necessary. | Medium | Medium |
| Scope | Legacy registration issues on Design, and configuration management issues | Scope includes Contractor to conduct an SCR/OPEX/documentation review early in design process to identify any current conditions. Contractor to review current TSSA registration as part of their design. | Medium | Medium |
| Schedule | Delays to project schedule due to regulatory approvals (such as Environmental Assessment) taking longer than planned. | Advise regulatory agencies in advance of the pending changes. Stage design release strategy to provided reasonable time, based on operating experience, for regulatory agencies to review each package. Escalated to Senior Management to expedite the Environmental Assessment approval to allow start of site preparation. Use of schedule contingency allowance if necessary. | High | High |
| Resources | Design and Procurement Engineering deliverables not reviewed by OPG in a timely manner which supports the schedule. | Appropriate in-house or Owner Support Service Engineering resourcing - project to have dedicated multidisciplinary support and expertise for timely reviews. Clear and appropriately frequent communication of review expectations with all stakeholders. | Medium | High |
| Quality/ Performance | Design Deliverables not delivered to required quality. | The oversight process is not currently defined. However, the project has budgeted for dedicated multidisciplinary support for appropriate Engineering oversight and in-line reviews. | Medium | High |
| Technical | Cost of EPC contract increases due to discovery work, existing systems do not have adequate capacity, and uncertainty in the estimate (AACE Class 3 -20/+30%) | This risk will be mitigated, with appropriate contingency assigned. | Medium | Medium |
| Other | Additional buried services, concrete, etc are present than currently accounted for. | A complete ground scan of the area was conducted. As per contract terms, Contractor is responsible for his own independent scan. Ensure Contractor begins detailed design with relocation of buried services EC's. | Medium | High |

**Additional Risk Analysis:**

As per N-INS-00120-10014 Project Risk Management, the Extensive Risk Management process was applied to this release. Risk workshops were used to identify risks and determine the risk exposure. In addition to the Most Likely costs for the risk impact estimates, the Minimum (optimistic) and Maximum (pessimistic) costs were identified. All risks were evaluated as documented in the Risk Register. A Monte Carlo analysis was completed using the set of risk range estimates, and the contingency as identified in this BCS was allocated to provide residual risk impact coverage at a confidence level of 85% (P85).

The location of the new facility has groundwater contaminated with tritium from the 2009 Injection Water Storage Tank spill. The latest geotechnical and environment sampling reports do not indicate a significant level of soil contamination; however, the groundwater is contaminated with low concentrations of tritium. Disposal costs for both the soil and contaminated ground water are included in the total project cost estimate of $108,051k. The risk remains that the tritium contamination is greater than the geotechnical investigation currently indicates. Therefore, the risk of additional disposal costs to dispose of contaminated groundwater due to larger than anticipated tritium concentrations, and the risk that some soil is contaminated and will require disposal to a contaminated landfill, are captured as a specific item in the risk management plan for this project.

The tornado diagram, below, shows the sensitivity of the NPV for the Heavy Water Management Operational Improvements scope of work to changes in assumptions regarding the major benefits.



The table below illustrates the contingency by release and year.

| | 2012 ($k) | 2013 ($k) | 2014 ($k) | 2015 ($k) | Total ($k) |
|---|---|---|---|---|---|
| Full Definition (currently released) | 921 | 1,975 | 0 | 0 | 2,896 |
| Partial Execution (requested now) | 705 | 3,392 | 0 | 0 | 4,097 |
| *Sub-Total* | *1,626* | *5,367* | *0* | *0* | *6,993* |
| Full Execution (requested later) | 0 | 5,547 | 8,461 | 2,922 | 16,930 |
| **Total** | **1,626** | **10,914** | **8,461** | **2,922** | **23,923** |

**Part H: Post Implementation Review (PIR) Plan**

| Type of PIR | Target Project In Service Date | Target PIR Completion Date |
|---|---|---|
| Comprehensive | 2015-10-15 | 2016-10-15 |

| Measurable Parameter | Current Baseline | Target Result | How will it be measured? | Who will measure it? (person/group) |
|---|---|---|---|---|
| $D_2O$ storage volume to meet needs of Refurb. Project | No refurbishment storage | 1700 $m^3$ $D_2O$ storage for Refurb project | Storage volume available in time for Refurb schedule | Refurb Prog – Project and Controls |
| $D_2O$ storage volume for TRF Operations | Insufficient storage to support optimal TRF operations | 400 $m^3$ provided for improved TRF operation | Storage volume for operational improvements | TRF Manager |
| Amount of drum Handling, Cleaning and Testing Facility at DNGS | No capability to clean and test drums in-house | Ability to clean and test 100/drums per year | Number of drums cleaned and tested per year | TRF Manager |
| | | | | |

**Part I: Definitions and Acronyms**

AACE – The Association for the Advancement of Cost Estimating
BCS – Business Case Summary
CNSC – Canadian Nuclear Safety Commission
DNGS – Darlington Nuclear Generating Station
EPC – Engineer, Procure, Construct
HWMB – Heavy Water Management Building
OPG – Ontario Power Generation
PDRI – Project Definition Rating Index
PIR – Post Implementation Review
PNGS – Pickering Nuclear Generating Station
PO – Purchase Order
TRF – Tritium Removal Facility
TSSA – Technical Standards and Safety Authority
T&C – Terms and Conditions

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## For Internal Project Cost Control

**Appendix A: Summary of Estimate**

| | | | |
|---|---|---|---|
| **Project Number:** | 16-31555 | **Facility:** | Darlington |
| **Project Title:** | D2O Storage And Drum Handling Project | | |

**Estimated Cost in k$**

| | LTD | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Future | Total | % |
|---|---|---|---|---|---|---|---|---|---|---|
| **OPG Project Management** | 770 | 657 | 663 | 1,007 | 782 | | | | 3,879 | 4 |
| **OPG Engineering** | 829 | 1,232 | 1,983 | 873 | 1,179 | | | | 6,096 | 6 |
| **Permanent Materials** | - | 2,020 | 4,124 | 6,859 | 1,091 | | | | 14,094 | 13 |
| **Design and Construction** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Consultants** | - | | | | | | | | | |
| **Other Contracts/Costs** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Interest** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Subtotal** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Contingency** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Total** | **3,034** | **10,688** | **38,782** | **40,880** | **14,667** | | | | **108,051** | **100** |
| **Removal Costs Included** | | | 650 | | | | | | 650 | 1 |

**Notes**

| | | | |
|---|---|---|---|
| **Project Start Date** | 2006-11-11 | **Project Completion or In-Service Date** | 15-Oct-15 |
| **Interest Rate** | 5.0% | **Escalation Rate** | 2.0% |
| **Definition Cost Included** | $16,393 k | **Estimate at Completion** | $84,128 k |

| **Prepared by:** | **Approved by:** |
|---|---|
| Mike Veilleux 31-July-2012<br>Project Manager | Dianne Gaine<br>Dianne Gaine 31-July-2012<br>Director, Darlington Projects |

**Appendix B: Comparison of Total Project Estimates**

| Phase | Release | Date (YYYY-MM-DD) | Total Project Estimate in Choose an item. (by year including contingency) | | | | | | Later | Total Project Estimate |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | | |
| Definition | Partial | 2006-10-22 | 1,872 | 1,728 | 3,992 | 13,253 | 14,938 | 600 | 0 | 36,383 |
| Definition | Full | 2012-06-14 | 1,564 | 306 | -10 | 0 | 1,174 | 10,779 | 94,479 | 108,292 |
| Execution | Partial | 2012-07-18 | 1,564 | 306 | -10 | 0 | 1,174 | 10,688 | 94,329 | 108,051 |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |

**Project Variance Analysis**

**Estimated Cost in k$**

| k$ | LTD | Total Project | | Variance | Comments |
|---|---|---|---|---|---|
| | | Last BCS | This BCS | | |
| **OPG Project Management** | 770 | 3,954 | 3,879 | (75) | The last BCS assumed that the full $3.6M from the previously approved Developmental Release would be spent. At the completion of the developmental release, the project had under spent. This, combined with the resulting interest reduction, is the cause of the variance between the last BCS and this BCS. As well, minor rounding resulted in a $1k reduction in the Design and Construction Costs. |
| **OPG Engineering** | 829 | 6,155 | 6,096 | (59) | |
| **Permanent Materials** | | 14,094 | 14,094 | 0 | |
| **Design and Construction** | [redacted] | [redacted] | [redacted] | [redacted] | |
| **Consultants** | [redacted] | [redacted] | [redacted] | [redacted] | |
| **Other Contracts/Costs** | [redacted] | [redacted] | [redacted] | [redacted] | |
| **Interest** | [redacted] | [redacted] | [redacted] | [redacted] | |
| **Subtotal** | [redacted] | [redacted] | [redacted] | [redacted] | |
| **Contingency** | [redacted] | [redacted] | [redacted] | [redacted] | |
| **Total** | **3,034** | **108,292** | **108,051** | **(241)** | |
| **Removal Costs Included** | | | 650 | 650 | Project includes removal of services and structures, such as TRF Truck Dock and TRF Trailers. |

## Appendix C: Financial Evaluation Assumptions

Key assumptions used in the financial model of the Project are (complete relevant assumptions only):

**Project Cost:**

(1) A fixed price has been provided for Phase I, and a second performance target price has been provided to include both Phase II and Phase III. These performance target prices are the basis of the design and construction costs.

**Financial:**

(1) 2% escalation
(2) 7% discount rate

**Project Life:**

(1) 2016 to 2055 for $D_2O$ Operational Improvements Storage Tanks
(2) 2016 – 2024 for Refurbishment $D_2O$ Storage tanks

**Energy Production:**

(1) Alternative 2 (Drum warehouse for Refurbishment $D_2O$) – 2011 update for System Economic Values (energy + capacity) used to calculate value of 4 month critical path outage extension of unit refurbishment outage.

**Operating Cost:**

(1) For the Preferred Alternative, the following incremental staff requirements were assumed to be required for the life of the new facility: Operator – 2 FTE, Control Maintainer – 0.5 FTE, Mechanical Maintainer – 0.5 FTE, Engineer – 0.5 FTE

**Other:**

Benefits for Operational Improvements

1. Avoids capital cost of refurbishing TRF or new TRF facility in 2035. Assume cost of $532M (2012$) and 30% probability
2. Reduces impact of an unplanned TRF outages on OPG ability to manage heavy water inventories. Assume 50% probability of saving $7.2M/yr (2012$) during 2025-2055
3. Improves ability to achieve incremental third party $D_2O$ sales. Assume 50% probability of $3.1M/yr during 2016-2043
4. OPG achieves dose savings during outages. Assume $450k/year (2012$) from 2016 to 2055
5. Reduces risk of need to detritiate primary heat transport $D_2O$ after storage in moderator S&I tanks during a Vacuum Building Outage/Station Containment Outage. Assume one occurrence eliminated saving $3.6M (2012$) and modeled as $600k (2012$) every 6 years
6. Elimination of Kinetrics Drum Handling Contract (pressure test. Assume saving of $30k/yr (2012$) from 2016 - 2055
7. Avoids risk of downgrading reactor grade $D_2O$ during acute recovery events or SUP outage. Assume savings of $0.9M (2012$) over 40 years, or $22k/yr

Note: For alternative 3, these benefits were started in 2018 when the $D_2O$ Operational Improvements were put in service.

Benefits for Building Refurbishment Tank Storage (1,700 $m^3$)

1. Avoid capital cost of building storage for Darlington $D_2O$ as part of decommissioning in 2055. Assume $78M (2012$)

Attach further detail as appropriate from the Financial Evaluation spreadsheet.

The following is the breakdown of released funds, including contingency, following approval of this BCS.

| | $k |
|---|---|
| LTD – under Developmental Release | [redacted] |
| Full Definition Release Project Costs | [redacted] |
| Full Definition Contingency | [redacted] |
| Partial Execution Release Project Costs | [redacted] |
| Partial Execution Release Contingency | [redacted] |
| Total | $30,930 |

The below table outlines the approved Phase I and requested Phase II cost break down.

| Deliverable | Approved Full Definition Release ($k) | Requested Now Partial Execution Release ($k) | Total ($k) |
|---|---|---|---|
| EPC Contract - Detailed Design | [redacted] | [redacted] | [redacted] |
| Contingency | [redacted] | [redacted] | [redacted] |
| EPC Contract - Site Preparation | [redacted] | [redacted] | [redacted] |
| EPC Materials | [redacted] | [redacted] | [redacted] |
| OSS Design Support (Phase I and II) | [redacted] | [redacted] | [redacted] |
| Interest | $683 | - | $683 |
| Project Management Oversight | [redacted] | [redacted] | [redacted] |
| OPG Design Oversight | $306 | $143 | $449 |
| OP PE Oversight | [redacted] | [redacted] | [redacted] |
| TRF Oversight | [redacted] | [redacted] | [redacted] |
| OPG Field Engineering - Site Prep | - | $166 | $166 |
| OPG Field Engineering - Design Phase | $121 | - | $121 |
| DCC Group Engineering | [redacted] | [redacted] | [redacted] |
| Travelling Expenses | [redacted] | [redacted] | [redacted] |
| New Horizons LAN Spec. | [redacted] | [redacted] | [redacted] |
| Total | $15,689 | $11,641 | $27,330 |

**Appendix D: References**

DNGS $D_2O$ Storage and Drum Handling Project Developmental BCS, D-BCS-38000-10001-R001
Project Charter, N-PCH-09701-10001
Life Extension Strategy for TRF, NK38-CORR-39000-0412581
Adverse Trend for Drum Handling Issues, SCR D-2012-04114
OPEX review of Drum Handling Issues, NK38-REF-38000-0427531
Project 16-31555: Office Space Requirements Within The New $D_2O$ Storage Facility, NK38-CORR-38000-0400715
Long Term Strategy for $D_2O$ Storage Upon Station Shutdown, N-REP-03800-10004 (Pickering Shutdown)

**This Guidance section should be deleted prior to submission of the BCS.**

## Guidance for Completing this Type 3 Form:

**Always use the latest revision of the Form!**
Verify this is the latest revision through PowerSearch,
or Finance BCS Toolkit intranet website.

### Final Security Classification

Determine the Final Security Classification of the BCS from the drop-down list before both the Executive Summary and Recommendations and Part A. Refer to OPG-STD-0030 Classification, Protection and Release of Information.

### Executive Summary and Recommendations

*Records File Information*

Refer to OPG-PROC-0019, Records and Document Management for the requirements and expectations of record filing after the BCS is submitted.

The SCI used for record filing should be:

- *00120.3* for Nuclear BCSs.
- *08707.021* for BCSs of all other business units and corporate groups.

Submitted BCSs shall also be filed according to local BU governance, which may require different SCIs.

*Project Overview*

State the following:

- What needs to be done and why it needs to be done.
- When the investment/project will be completed.
- Key business objectives.
- Expected benefits of the investment/project.
- Whether the investment/project is within the original scope as specified in the approved Business Plan and/or Life Cycle Plan.
- Brief history of previous releases.
- Level of confidence for current request.
- If critical to the decision, any constraints on the investment/project or its timing.

*Project Cash Flows*

This table in the Executive Summary and Recommendations section is the same as the table in Part D: Project Cash Flows. See guidance for Part D: Project Cash Flow.

*Approvals*

Provide the title and name of the individuals making the three required signatures: the Project Sponsor, the individual providing Finance Approval, and the Approver of the BCS per the OAR. The Comments cell is to allow brief hand-written comments. For example, "see comment on Part D", which would refer to a hand-written comment later in the BCS document. These comments would be minor in nature; otherwise a reviewer would require revisions to the BCS before signing the document.

## Business Case Summary

### Part A: Business Need

This section describes the business needs or opportunities that gave rise to the investment. It provides background and context for the investment including: the investment's purpose, what's driving the investment, why the investment needs to be addressed now, what are the impacts of not proceeding, key assumptions, identification of any subsequent commitments or obligations, and the benefits or constraints that the investment will create. Provide studies, experience or lessons learned from similar investments, if available. If this submission relates to a subsequent approval, provide a quick overview of investment history.

If the investment is a subset of a program, or if the issue to be addressed is symptomatic of a broader issue that requires additional response, provide the context and identify the related response, whether planned or anticipated.

### Part B: Preferred Alternative

This section describes expected business results and objectives, including resourcing requirements, when the investment will be completed, and any major milestones. The proposal section must put the investment into the proper context by providing the link between the investment and the business strategy for the asset and/or other planned investments in that asset.

Describe the link between this investment and business strategy or other investments. Disclose if the resourcing is in place. Alternatively, if the investment is not in the business plan, or if the scope has changed relative to the Business Plan, reasons for the change(s) must be provided.

State the expected benefits and what is being delivered, without specifying vendor name(s). Describe briefly project execution strategy, regulatory approvals, third party agreements, project management, and basis for the cost and schedule contingencies, if applicable. Highlight any constraints on the investment or on its timing, and any constraints or obligations created by the investment.

*Deliverables*

In the Deliverables section, list the project deliverables and target completion dates, including associated milestones (such as unit in-service dates and external or regulatory milestones).

### Part C: Other Alternatives

This section describes viable alternatives considered, including associated risks. At minimum, include a Base Case: Status Quo – No Project. Other alternatives may include:

- Deferring the project.
- Different means to meet the same business need.
- Completing partial scope.
- Alternatives with additional scope.

### Part D: Project Cash Flows

This table in Part D: Project Cash Flows is very similar to the table under Project Cash Flows in the Executive Summary and Recommendations section.

This table provides a yearly breakdown of estimated project costs, including amounts currently released from earlier BCSs if applicable, the new amounts being requested now in this BCS, and estimated future requirements not currently requested. Contingency shall be included in these amounts.

The new amounts being requested are for actual work to be completed and for any costs that will be committed to through that work. For example, if an equipment purchase is bundled with a maintenance contract for a committed period, the committed payments under the maintenance contract must be included in the current request. Ongoing Costs include any costs related to the investment that would not be part of the project budget, including ongoing incremental operating costs, and acquisition of inventory.

The Future column is the sum of expected future cash flows beyond the last year shown in the table.

*Estimate Class*

Estimate Class is a cost estimate classification system developed by the Association for the Advancement of Cost Engineering International (AACE) which defines the estimate "quality" based on the input information used and the project's stage of development. AACE uses five estimate classes with Class 5 being the least accurate, and Class 1 being the most accurate.

| **Estimate Class** | **Class 5** | **Class 4** | **Class 3** | **Class 2** | **Class 1** |
|---|---|---|---|---|---|
| **Phase** | **Identification** | **Initiation** | **Definition** | **Execution** | **Execution** |
| **Level of Project Definition (%)** | 0% to 2 | 1 to 15 | 10 to 40 | 30 to 75 | 65 to 100 |
| **Expected Accuracy Range (%)** | -50 to +100 | -30 to +50 | -20 to +30 | -15 to +20 | -10 to +15 |

*OAR Approval Amount*

For BCSs up to and including Definition Phase work, the OAR Approval Amount is the cumulative total actual and committed cost to date, not the estimated total investment/project cost. For Execution Phase BCSs or BCSs that cover multiple phases including Execution, the OAR Approval Amount is the estimated total investment/project cost, including cumulative cost to date.

*Additional Information on Project Cash Flows (optional)*

Relevant information such as the delta between approved business plan cash flows and requested release, may be entered into this open-field table cell.

**Part E: Financial Evaluation**

This section describes and compares the key alternatives considered. Only the most relevant alternatives shall be listed in this table for comparison. The analysis includes financial evaluations, economic analysis, and comparisons of the alternatives based on total project cost, after-tax NPV, and any other financial metric deemed appropriate by the project sponsor (e.g., IRR, discounted payback, etc.) The BCS Financial Evaluation Model is available on the Finance website and is updated periodically to help facilitate financial analysis. Attach further detail as appropriate from the Financial Evaluation spreadsheet.

*Summary of Financial Model Key Assumptions*

List key assumptions used in the Financial Evaluation. For Part E, provide a brief summary of the most important assumptions that are listed in Appendix C.

**Part F: Qualitative Factors**

Qualitative factors gained (or lost) from the investment and how an initial specification will be measured within the post implementation review (to the extent feasible). Qualitative factors could include: sustainable energy development impacts; community, government, and customer relations; staff relations issues, technical or operational considerations, reliability, health and safety issues, and other intangibles.

**Part G: Risk Assessment**

This section identifies the risks associated with the investment and the plans to manage or mitigate these risks. Refer to OPG-STD-0062, Project Risk Management Standard and local business unit standards for guidance on completing and documenting risk assessments. Each BU can add risk areas specific to its business.

Extra Risk Classes may be added by changing "Other" to a specific risk class and/or inserting extra rows to the table.

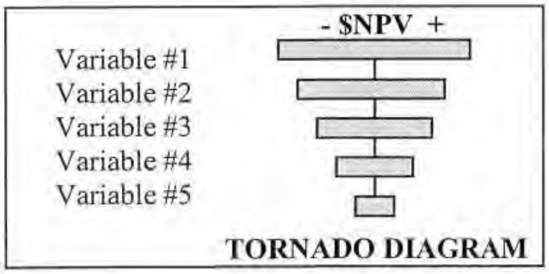
The Risk Analysis section discusses, as appropriate for the project, quantitative risk factors that relate to the project financial evaluation, including considerations such as:

- Present and discuss material impacts/consequences of variations in the basic assumptions, e.g., price of electricity used for revenue, sales forecast, service life, etc. Discuss likelihood of occurrence.

- Based on risks identified and mitigation measures implemented, indicate whether the financial analysis completed for the recommended alternative includes the contingency required for OPG residual risks, and their impact on the estimated in-service date.

- The extent of the risk assessment and the risk analysis techniques employed should be commensurate with the magnitude of the cash flows and the degree of uncertainty associated with the critical assumptions upon which the investment is based.

- For Major Projects, the risk analysis section will typically include sensitivities of the investment to various risk factors or scenarios, and a discussion of their likelihood of occurrence. A convenient way of presenting the results of the risk assessment on the variability of the NPV to changes in the critical variable is to include a graph or tornado diagram as shown below.



TORNADO DIAGRAM

- For larger investments, more advanced risk analysis techniques such as Monte Carlo may be suitable. These techniques require analysts with appropriate training; contact your local Finance support to discuss applicability and to arrange Finance analytical support if required. The limitations of Monte Carlo or any other risk assessment technique must be considered in their application, and require a time commitment from the project team and stakeholders to develop and estimate model inputs.

**Part H: Post Implementation Review (PIR) Plan**

PIR plan is a succinct description of the project benefits using measurable parameters. The PIR plan should clearly specify what is to be measured, who is responsible for measuring it, and when the measurement should take place, along with any requirements for establishing pre-project baseline information for comparison purposes.

Extra PIR metrics may be added by inserting extra rows to the table.

The PIR plan should contain the following five main elements:

- What: Key deliverables or benefits of the project clearly defined in measurable parameters, including a clear description of the reference or baseline from which the incremental benefits or changes due to the project are to be measured.

- How: A brief description of how each parameter is going to be measured.

- Who: The name of the group, department, or individual that will be measuring the benefits.

- When: When the measurement of the benefits will take place.

In addition, the Project Sponsor and key stakeholders may specify other items such as the types of lessons learned and recommendations to be captured during the execution of the PIR.

**Part I: Definitions and Acronyms**

Define key technical terms and list acronyms to assist reviewers of the document.

**Appendix A: Summary of Estimate**

**Note:** All content from Appendix A onwards, including this Guidance section, contains a level of detail that is intended for OPG internal use only and should be removed before a copy of a BCS is released to an external party.

To assist the reviewer in understanding the cost estimate in the BCS, this table provides a breakdown of various cost components by year, with explanatory notes as appropriate.

**Note:** The label "Project Completion or In-Service Date" is intended to provide flexibility for projects that do not have a specific "In-Service Date", such as engineering studies in future decisions or for future regulatory documents.

### Appendix B: Comparison of Total Project Estimates and Project Variance Analysis

This section provides the history of past releases and their associated estimates, with explanations of changes as appropriate.

### Appendix C: Financial Evaluation Assumptions

This section is intended to provide a reviewer with an overall understanding of the key assumptions used in the financial evaluation, to help a reviewer confirm that relevant drivers and appropriate assumptions were used in the analysis. The main considerations in the economic evaluation of the alternatives are outlined below:

*Cost and Schedule Estimates*

The work breakdown structure (WBS) of the project usually provides detailed information on the cost of the project and should be referred to while estimating the costs and schedule. Best practices in project cost and schedule estimating should be applied wherever possible including using lessons from similar experiences and benchmarks. Requests for quotations from competitive sources are another option to obtain detailed estimates. Schedule and cost estimates must obtain stakeholders' inputs and be reviewed by the key stakeholders of the project before being finalized.

*Taxes*

All investments must be assessed on an after-tax basis. Users will be required to properly classify the capital assets for Capital Cost Allowance (CCA) purposes. The financial evaluation model provided on the Finance website will compute the initial income tax impacts for most types of investments; the model also contains the latest CCA rates for most types of investments. For further information on CCA, sales taxes and tax shields, please contact your local Finance support group.

*Cost of Capital*

An appropriate cost of capital or discount rate must be used to ensure that an adequate return is provided to shareholders. For investments related to the manufacturing and processing of electricity for regulated nuclear and base-loaded hydroelectric facilities, the discount rate is generally lower than for unregulated facilities. This is partly due to regulated assets having a more predictable revenue stream, and hence lower risk than unregulated generation facilities.

For projects and business opportunities that are clearly outside of OPG's core business, or are not related to the manufacturing and processing of electricity, the project's cost of capital should be used, instead of OPG's cost of capital. Updated rates for OPG's core business are posted in the BCS Financial Evaluation Model. Contact Investment Planning for assistance.

*Revenue Forecasts*

The revenue forecast from generation assets must be based on the OPG System Economic Values (SEVs). The appropriate SEVs for the applicable time frame are selected based on the characteristics of the generation asset being evaluated (e.g., peaking vs. baseload). Contact your local Finance support group for further guidance on using SEVs.

### Appendix D: References

The reference documentation and attachments contain the detailed numbers, calculations, and any other analysis done probing the need and substantiating the justification for the investment. This documentation includes: cost estimates, financial evaluation sheets, risk assessment tables, modeling assumptions, project execution plan, technical studies, and any other specific studies related to the investment.

**Additional Attachments**

Additional documents be prepared as separate documents and enclosed with the BCS for reviews and approvals (e.g., multiple file attachments to e-mails).

The final signed version of the BCS may then be combined with all the attachments in a single PDF file.

Records File Information:
See Guidance Section

OPG-FORM-0076-R005

# Type 3 Business Case Summary

Final Security Classification of the BCS: **OPG Confidential**

To be used for investments/projects meeting Type 3 criteria in OPG-STD-0076.

## Executive Summary and Recommendations

| | | | |
|---|---|---|---|
| **Project #:** | 16-25619 | **Title:** | Operations Support Building (OSB) Refurbishment Project |
| **Phase:** | Definition | **Release:** | Full |
| **Facility:** | Darlington | **Records File:** | NK38-BCS-28110-10001 |
| **Class:** | Capital and OMA | **Investment Type:** | Sustaining |

**Project Overview**

**We recommend the release of $1,975 k ($[redacted] base costs plus [redacted] .**

This funding will support the following deliverables:

- Detailed design phase of Engineering, Procure, Construct (EPC) Contract, including constructability reviews and installation planning
- Development of detailed employee relocation plan
- Execution-Full release Business Case Summary (BCS) and estimate

The Operations Support Building (OSB) is an important building on the Darlington Nuclear Generating Station (DNGS) site that houses technical services essential to the business operations of DNGS, including Local Area Network (LAN) servers, telephone network hubs and security systems. It also houses 375 employees who provide daily support to station and control room staff.

The business objective of the project is to:

- Provide a secure facility for the essential technical services located on the first floor and basement of the OSB.
- Provide a viable office facility with enough space to accommodate the DNGS support staff located in the OSB.

Completing these business objectives will ensure that the OSB remains operational for the next 25 years to support the ongoing operations of DNGS post-refurbishment.

A building condition assessment documented deficiencies with most building systems and highlighted equipment that is at or near the end of their service life. The project will refurbish or replace mechanical, electrical, controls and civil systems located on all floors of the building as well in the cafeteria, the roof and the exterior cladding and windows. A value engineering workshop was completed to confirm the necessary refurbishment activities.

# Type 3 Business Case Summary

**Project Cash Flows**

| k$ | LTD | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Future | Total |
|---|---|---|---|---|---|---|---|---|---|
| Currently Released | 1,888 | 513 | | | | | | | 2,401 |
| Requested Now | - | 247 | 1,728 | | | | | | 1,975 |
| Future Required | - | | 3,590 | 23,896 | 14,369 | 563 | | | 42,418 |
| **Total Project Cost** | 1,888 | 760 | 5,318 | 23,896 | 14,369 | 563 | | | 46,794 |
| Ongoing Costs | - | | 854 | 2,048 | 2,343 | 1,351 | 1,373 | 787 | 8,754 |
| **Grand Total** | 1,888 | 760 | 6,172 | 25,944 | 16,712 | 1,914 | 1,373 | 787 | 55,548 |

| | | | |
|---|---|---|---|
| **Estimate Class:** | Class 4 | **Estimate at Completion:** | 46,795k |
| **NPV:** | $23,236 k | **OAR Approval Amount:** | 4,376k |

**Additional Information on Project Cash Flows (optional):**

The total requested now of $1,975k is capital.

The total project cost of $46,794k consists of $44,006k in capital expenditures and $2,788k in project OM&A for furniture and other non-fixed assets.

The ongoing costs of $8,754k are base OM&A costs to support the relocation of employees ($476k) and to support the lease and operating costs of swing space between 2014 and 2018 ($8,728k).

**Approvals**

| | Signature | Comments | Date |
|---|---|---|---|
| This BCS represents the best option to meet the validated business need in a cost effective manner. | | | |
| **Recommended by:**<br>Don Seedman<br>Project Sponsor | | | |
| I concur with the business decision as documented in this BCS. | | | |
| **Finance Approval:**<br>Randy Leavitt<br>Vice President, Nuclear Finance | | | |
| I confirm this project will address the business need, is of sufficient priority to proceed, and provides value for money. | | | |
| **Approved by:**<br>Deitmar Reiner<br>Senior Vice President, Nuclear Refurbishment, per OAR 1.1 | | | |

# Type 3 Business Case Summary

Final Security Classification of the BCS: **OPG Confidential**

## Business Case Summary

| **Part A: Business Need** |
|---|
| **Business Need:**<br>The purpose of this investment is to extend the life of the OSB by 25 years to support the ongoing operations of the refurbished Darlington station.<br>The OSB is an important facility at DNGS as it houses technical services that are essential to the business operations of DNGS. These technical services include: Security systems, site IT and telephone network hubs, quality assurance vault, station domestic water piping and radiological public domain access to the powerhouse via the bridge. This facility also provides office and conference room space for 375 employees and various speciality groups inside the DNGS protected area.<br>An assessment performed by an external engineering firm found that many of the existing building systems are currently, or will be, life expired by 2015. Several systems need to be replaced such as the cladding and windows, roof membrane, HVAC system (equipment and ducting), elevator, plumbing, electrical distribution, IT and telephone, cafeteria, furniture, interior furnishings including the carpet and ceiling tiles. Other systems need to be installed such as a sprinkler system and interior overhead lighting.<br>The continued degradation of the OSB will increase the likelihood of additional mould growth, worsened employee engagement and increased corrective maintenance to repair failing equipment, which will cause poor environmental conditions for the essential technical services and building occupants. |

**Part B: Preferred Alternative**

**Description of Preferred Alternative: Refurbish OSB while unoccupied**

This alternative provides for the refurbishment of the OSB including the temporary relocation of approximately 375 employees to the ESSB/MSB buildings at DNGS and approximately 375 employees to an off-site leased facility until the end of the project in 2015.

This is considered the recommended solution for the following reasons:

- Satisfies the business objectives while providing the best value for money
- Technical services essential to DNGS business operations are maintained in a cost effective manner
- Returns the building to operation in the shortest amount of time.
- Provides office space within the protected area for approximately 375 employees for the next 25 years
- Utilizes the structure of the OSB, which is an asset of considerable value

| **Deliverables:** | **Associated Milestones (if any):** | **Target Date:** |
|---|---|---|
| **Current Release (Definition-Full):** | **Current Release (Definition-Full):** | |
| • Execution-Full Release estimate and associated BCS | Execution-Full Release Funding Approved | 05-SEP-2013 |
| • Completion of detailed design | Design Complete | 03-DEC-2013 |
| **Future Release (Execution-Full):** | **Future Release (Execution-Full):** | |
| • Completion of construction, commissioning and Available for Service (AFS) | Available for Service and/or Ready for Service Completed | 09-SEP-2015 |
| • Project close out | Plan Complete Milestone | 04-NOV-2016 |

## Type 3 Business Case Summary

**Part C: Other Alternatives**

**Alternative 2: Base Case - Permanently relocate OSB employees to an off-site leased facility until 2062, refurbish first floor and basement and demolish second and third floors**

This alternative includes the *permanent* relocation of approximately 375 staff currently occupying the OSB to an off-site leased facility until the end of Darlington life (2062). This alternative also includes:

- The refurbishment of the first floor and basement, to maintain the operation of the essential technical services.
- Demolition of the second and third floors of the OSB as the condition of the non-refurbished space will not be suitable for use but will still need to be maintained over the long term

The base case does not provide the best value for money and is not recommended for the following reasons:

- Requires significant work to be completed to OSB in order to maintain the technical services and demolish unuseable space.
- Subsequent loss of 54,000 sq.ft of useable space within the protected area.
- Real estate risk due to changing market conditions, availability of leasable space, and uncertainty of lease costs
- Loss of valuable building work space within the protected area

Loss of productivity due to increased travel time for off-site staff requiring occasional or frequent access to the protected area

**Alternative 3: Refurbish basement and first floor, demolish second and third floor, construct a new off-site facility on OPG owned property**

This alternative includes:

- Refurbishment of the basement and first floor to maintain the essential technical services that currently exist in the OSB
- Demolition of the second and third floors of the OSB as the condition of the non-refurbished space will not be suitable for use but will still need to be maintained over the long term
- Construction of a new *off-site* facility to house approximately 375 employees currently accommodated in the OSB

Although this alternative satisfies the business objectives for this project, it is not recommended for the following reasons:

- Does not provide the best value for money
- Requires significant work to be completed to OSB in order to maintain the technical services and demolish unuseable space.
- Loss of valuable building work space within the protected area
- Loss of productivity due to increased travel time for off-site staff requiring occasional or frequent access to the protected area
- Reduces space efficiency – functions currently housed in the OSB will be separated into two buildings

Two other locations were considered for the construction of a new facility. The locations included constructing a new facility inside the protected area, or constructing a new facility outside the protected area on the DNGS campus. Upon analysis of these locations, both of these locations provided less value for money than a new facility off-site. In addition, the DNGS campus plan does not indicate space available for this new facility.

**Alternative 4: Relocate OSB essential technical services, demolish OSB and construct a new facility in the same location**

This alternative includes the relocation of all essential technical services currently housed in the OSB to a new location on the Darlington campus, complete demolition of the OSB, and construction of a new building on the OSB site.

This alternative does not provide the best value for money and is not recommended for the following reasons:

- Significant operational and cost risks associated with the relocation of Darlington essential technical services
- Radiological public domain access to station via the powerhouse bridge will be significantly impacted by construction.
- Temporary loss of valuable building work space within the protected area and the subsequent loss of productivity due to increased travel time through security procedures into the protected area

Security and operational risks associated with moving the IT Wide and Local Area Server Room and related IT spaces outside of the protected area

**Part D: Project Cash Flows**

| k$ | LTD | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Future | Total |
|---|---|---|---|---|---|---|---|---|---|
| Currently Released | 1,888 | 513 | | | | | | | 2,401 |
| Requested Now | - | 247 | 1,728 | | | | | | 1,975 |
| Future Required | - | | 3,590 | 23,896 | 14,369 | 563 | | | 42,418 |
| **Total Project Cost** | 1,888 | 760 | 5,318 | 23,896 | 14,369 | 563 | | | 46,794 |
| Ongoing Costs | - | 0 | 854 | 2,048 | 2,343 | 1,351 | 1,373 | 787 | 8,754 |
| **Grand Total** | 1,888 | 760 | 6,172 | 25,944 | 16,712 | 1,914 | 1,373 | 787 | 55,548 |

| | | | | | |
|---|---|---|---|---|---|
| **Estimate Class:** | Class 4 | **Estimate at Completion:** | 46,795k | **OAR Approval Amount:** | 4,376k |

**Additional Information on Project Cash Flows (optional):**

The total requested now of $1,975k is capital.

The total project cost of $46,794k consists of $44,006k in capital expenditures and $2,788k in project OM&A for furniture and other non-fixed assets.

The ongoing costs of $8,754k are base OM&A costs to support the relocation of employees ($476k) and to support the lease and operating costs of swing space between 2014 and 2018 ($8,728k).

**Part E: Financial Evaluation**

| k$ | Preferred Alternative | Alternative 2: Base Case | Alternative 3 | Alternative 4 | |
|---|---|---|---|---|---|
| **Project Cost** | 46,795 | 38,528 | 52,322 | 145,334 | |
| **NPV (after tax)** | 23,236 | N/A | (8,464) | (52,037) | |
| **Other (e.g., LUEC)** | | | | | |

**Summary of Financial Model Key Assumptions (see Guidance on this Type 3 BCS Form):**

The financial model considers the capital costs to implement each alternative, swing space lease and operating costs where required, long-term capital improvement program costs, increase or decrease in operating and maintenance overtime costs, relocation costs and mileage costs. The costs were calculated until 2062 (assumed end of Darlington station life including safe storage activities).

**Part F: Qualitative Factors**

1. Maximizes the number of staff working in close proximity to the Darlington power house
2. Site infrastructure is already in place to support the refurbishment of the OSB and its continued operation
3. Essential technical services housed in the OSB will remain in place and be maintained throughout the construction period
4. Concerns over IT/LAN network performance, workstation ergonomics, task lighting, air quality, food services, and work place environment will be resolved as part of the refurbishment.
5. Resolution of issues raised in SCRs will improve staff productivity and engagement

**Part G: Risk Assessment**

| Risk Class | Description of Risk | Risk Management Strategy | Post-Mitigation | |
|---|---|---|---|---|
| | | | Probability | Impact |
| Cost | Project cost estimates assumed that the EPC Contractor will be the constructor per OHSA. If OPG needs to become the constructor, there will be an increase in the overall project cost. | To be mitigated by the project team. The Contractor Safety Compliance department has confirmed that it is acceptable to manage this project with the EPC Contractor as the constructor. | Medium | Low |
| Scope | Refurbishment of the OSB has potential for scope increases due to discovery of hidden building systems as well as construction interferences. OSB is a 30 year old building located in a high traffic and congested part of the security protected area and has system connections to the nuclear station. | To be mitgated by the project team. Value engineering workshop was completed that validated the project scope. An architectural/engineering design agency has produced a Building Requirements document that details the modifications to be completed in each room of the building. During detailed design, the EPC Contractor will be required to complete thorough walk downs to uncover as many discovery issues as possible. | High | Medium |
| Schedule | The project schedule plans for the relocation of OSB employees to occur in the summer of 2013 (prior to the DNGS 2013 fall outage) and requires the Darlington Energy Complex to be available for occupancy prior to the end of June 2013, | Risk to be mitigated by Corporate Real Estate, who has the accountability to develop the project relocation strategy. Planned completion of Darlington Energy Complex is early July 2013. | Medium | Medium |
| Resources | The project may require dedicated security resources for compensatory measures due to construction activities in close proximity to the protected area fence. | Risk to be mitigated by the project team and Darlington Nuclear Security Operations. The project performed a walk down with a general contractor to identify alternative construction methods that will enable the safe completion of the work while eliminating the impact on security regulations and reducing the security resources required. | Medium | Medium |
| Quality/ Performance | | | | |
| Technical | EPC Contractor installation plan does not properly protect one of the essential services, causing a disruption of services at the DNGS site, such as IT, telephone or security. | An exhaustive list of essential services has been documented in the EPC contract scope of work based on stakeholder feedback. The project will provide oversight to ensure the management of essential services is completed by the EPC Contractor. | Medium | Medium |
| Other | Swing space has not yet been officially secured; Without the swing space, the relocation of employees cannot proceed, which would significantly impact construction plans. | Risk will be mitigated by Corporate Real Estate, who is aware of the project swing space requirements and has a plan to secure the necessary space. | Low | High |

**Additional Risk Analysis:**

An extensive risk identification and analysis was completed per OPG-STD-0062. A monte carlo simulation was completed to identify the required cost and schedule contingencies.

**Part H: Post Implementation Review (PIR) Plan**

| Type of PIR | Target Project In Service Date | Target PIR Completion Date |
|---|---|---|
| Comprehensive | 09-SEP-2015 | 09-SEP-2016 |

| Measurable Parameter | Current Baseline | Target Result | How will it be measured? | Who will measure it? (person/group) |
|---|---|---|---|---|
| Successful completion of commissioning specifications based on building requirements (NK38-TS-28110-10001). | OSB systems are at or near end of service life. Building Requirements (NK38-TS-28110-10001) document identifies required building improvements. | Building is occupied by employees and systems operate within building requirements. | OSB systems, structures and components are successfully commissioned and remain available for service throughout PIR period. | Nuclear East Facilities |

**Part I: Definitions and Acronyms**

1) Building Requirements document: The document prepared by an external architect/engineering firm that describes the modifications to be completed in each room of the building, along with the performance specifications of those modifications.
2) EPC: Engineering, Procure, Construct
3) ES MSA Contractors: Extended Services Master Services Agreement between OPG and preferred contractors.
4) Essential Technical Services: Important equipment located in the OSB that facilitates business operations across the site including security systems, information technology LAN servers, telephone network hub, station domestic water piping and radiological public domain access to the station via the bridge.
5) OHSA: Occupational Health and Safety Act
6) OSB: Operations Support Building
7) Swing Space: Temporary office space for OSB employees while construction taking place.

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Filed: 2013-09-27
EB-2013-0321
Ex. D2-2-1
Attachment 8-4

# For Internal Project Cost Control

OPG-FORM-0076-R003

# Type 3 Business Case Summary

**Appendix A: Summary of Estimate**

| | | | |
|---|---|---|---|
| **Project Number:** | 16-25619 | **Facility:** | Darlington |
| **Project Title:** | Operations Support Building Refurbishment Project | | |

**Estimated Cost in k$**

| | LTD | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Future | Total | % |
|---|---|---|---|---|---|---|---|---|---|---|
| **OPG Project Management** | 1,034 | 465 | 399 | 289 | 307 | 221 | | | 2,715 | 6 |
| **OPG Engineering** | 92 | 30 | 103 | 137 | 120 | 8 | | | 490 | 1 |
| **Permanent Materials** | | | | | | | | | | |
| **Design and Construction** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Consultants** | | | | | | | | | | |
| **Other Contracts/Costs** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Interest** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Subtotal** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Contingency** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Total** | **1,889** | **759** | **5,317** | **23,897** | **14,370** | **563** | | | **46,795** | |
| **Removal Costs Included** | | | 261 | 2,230 | 88 | | | | 2,578 | 6 |

**Notes**

| | | | |
|---|---|---|---|
| **Project Start Date** | 04-MAR-2009 | **Project Completion or In-Service Date** | 09-SEP-2015 |
| **Interest Rate** | 6% | **Escalation Rate** | 3% |
| **Definition Cost Included** | $4,376 k | **Estimate at Completion** | $46,795 k |

| **Prepared by:** | | **Approved by:** | |
|---|---|---|---|
| Chris Waugh | 2012-09-18 | Stephanie Tham | 2012-09-18 |
| Modification Team Leader | YYYY-MM-DD | Manager, Design Projects | YYYY-MM-DD |

**Appendix B: Comparison of Total Project Estimates**

| Phase | Release | Date (YYYY-MM-DD) | Total Project Estimate in k$ (by year including contingency) | | | | | | Later | Total Project Estimate |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | | |
| Definition | Partial | 2009-MAR-09 | 5,482 | 1,865 | 1,649 | 200 | | | | 9,196 |
| Definition | Partial | 2010-NOV-08 | 3,094 | 1,081 | 6,885 | 31,613 | 4,336 | 413 | | 47,395 |
| Definition | Full | 2012-OCT | 1,889 | 759 | 5,317 | 23,897 | 14,370 | 563 | | 46,795 |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |

**Project Variance Analysis**

**Estimated Cost in** k$

| k$ | LTD | Total Project | | Variance | Comments |
|---|---|---|---|---|---|
| | | Last BCS | This BCS | | |
| **OPG Project Management** | 1,034 | 5,807 | 2,715 | (3,092) | Project will now utilize an ES MSA vendor to complete an EPC contract. Oversight requirements from OPG are reduced due to this change in strategy. |
| **OPG Engineering** | 92 | 354 | 490 | 136 | Previously, an external design agency was providing oversight of the general contractor. Now, OPG will be providing this oversight. |
| **Permanent Materials** | 0 | 0 | 0 | 0 | Material costs are included in the construction costs. |
| **Design and Construction** | [redacted] | [redacted] | [redacted] | [redacted] | Value engineering workshop was completed and a detailed building requirements document was prepared. The project cost estimates have taken into account the additional scope and construction activities that were not originally anticipated by the first estimate. |
| **Consultants** | [redacted] | [redacted] | [redacted] | [redacted] | |
| **Other Contracts/Costs** | [redacted] | [redacted] | [redacted] | [redacted] | |
| **Interest** | [redacted] | [redacted] | [redacted] | [redacted] | The previous BCS estimate had more OM&A costs forecasted than this BCS, thus less interest. |
| **Subtotal** | [redacted] | [redacted] | [redacted] | [redacted] | |
| **Contingency** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Total** | **1,889** | **47,393** | **46,795** | **(598)** | |
| **Removal Costs Included** | | 2.527 | 2,578 | 51 | |

## Appendix C: Financial Evaluation Assumptions

Key assumptions used in the financial model of the Project are (complete relevant assumptions only):

**Project Cost:**

(1) The project costs for the preferred alternative were calculated by the Projects and Modifications external cost estimator using the value engineering workshop results and the project scope documented in the Building Requirements prepared by the preliminary design architect/engineering services firm.

(2) The project costs for the other alternatives were calculated by the external architectural firm who prepared the project alternatives analysis report.

**Financial:**

(1) The project alternatives analysis report identified yearly capital costs to replace/upgrade building systems throughout the entire life cycle analysis for each alternative. These costs have been included in the net present value calculations.

(2) Swing space and relocation costs have been included in the net present value calculations for each alternative as necessary but not in the project costs.

(3) Mileage costs have been assumed for each alternative for employees traveling between the Darlington site and the planned swing space location in Oshawa, ON.

**Project Life:**

(1) The life cycle analysis for this project forecasts costs until 2062. This assumes the need for the OSB until the end of Darlington station life including safe storage of the nuclear units.

**Energy Production:**

(1) This project will not have any impact on the energy production of the Darlington units.

(2) This project will not have any impact on the successful completion of the Darlington station containment outage in 2015.

**Operating Cost:**

(1) For alternatives 1, 2 and 4, it was assumed that there will be a decrease in the operation and maintenance staff overtime requirements due to improved building systems or minimized building space being maintained by OPG staff; this has been reflected in the net present value calculations.

(2) For alternative 3, it was assumed that there will be an increase in operations and maintenance staff overtime requirements because there will be a new facility in addition to the existing OSB first floor and basement remaining in service.

**Other:**

Attach further detail as appropriate from the Financial Evaluation spreadsheet.

## Appendix D: References

1) D-PCH-15000-10009 – Project Charter
2) D-BCS-15000-10002 – Developmental BCS (Initiation-Full)
3) D-BCS-28100-10001 – Developmental 2 BCS (Definition-Partial)
4) NK38-PEP-28100-0366501 – OSB Refurbishment Developmental 2 Project Execution Plan
5) NK38-REP-28110-0322001 – Operations Support Building - Building Condition Assessment Report
6) NK38-REP-28110-0394044 – OSB Refurbishment Project Alternatives Analysis

**OSB Refurbishment**
**25619**

## Summary of Alternatives

| $000's | | Alt 1 (Recommended) | | Alt 2 | Alt 3 | Alt 4 | Alt 5 |
|---|---|---|---|---|---|---|---|
| | Base Case | Full Cost | Incremental Cost | | | | |
| PNGSB Unit 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PNGSB Unit 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PNGSB Unit 7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PNGSB Unit 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| | | | | | | | |
| DNGS Unit 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DNGS Unit 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DNGS Unit 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DNGS Unit 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| | | | | | | | |
| PNGSA Unit 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PNGSA Unit 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PNGSA Unit 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PNGSA Unit 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **Total Revenue** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| Base OM&A | (201,241) | 641 | 641 | 0 | (97,527) | 643 | 0 |
| Outage OM&A | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Project OM&A | (2,981) | (2,788) | (2,788) | 0 | (2,981) | 0 | 0 |
| **Total OM&A** | **(204,222)** | **(2,147)** | **(2,147)** | **0** | **(100,508)** | **643** | **0** |
| **Provision** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **Capital Expenditures** | **(44,875)** | **(49,328)** | **(47,126)** | **0** | **(87,053)** | **(142,735)** | **0** |
| | | | | | | | |
| **Present Value (PV)** | **(61,476)** | **(38,240)** | **(36,252)** | **0** | **(69,939)** | **(113,512)** | **0** |
| **Net Present Value (NPV)** | **N/A** | **23,236** | **25,224** | **0** | **(8,464)** | **(52,037)** | **0** |
| | | | | | | | |
| **IRR%** | **N/A** | **8.3%** | **10.4%** | **N/A** | **N/A** | **N/A** | **N/A** |
| **Discounted Payback (Yrs)** | **N/A** | **7.58** | **6.65** | **N/A** | **N/A** | **N/A** | **N/A** |

ONTARIO POWER GENERATION

Records File Information:
See Guidance Section

OPG-FORM-0076-R003*

# Type 3 Business Case Summary

Final Security Classification of the BCS: **OPG Confidential**

To be used for investments/projects meeting Type 3 criteria in OPG-STD-0076.

**Executive Summary and Recommendations**

| | | | |
|---|---|---|---|
| **Project #:** | 16-34000 | **Title:** | Darlington Auxiliary Heating System Project |
| **Phase:** | Execution | **Release:** | Partial |
| **Facility:** | Darlington | **Records File:** | D-BCS-00120.3-10003 |
| **Class:** | Capital | **Investment Type:** | Regulatory |

**Project Overview**

**We recommend the release of $33,027 k ($[redacted] base costs plus [redacted]).**

This release will fund the engineering, procurement and construction of the new DNGS Auxiliary Heating System (AHS) Boilerhouse Facility. The project scope is to construct a new Boilerhouse and subsequently demolish the existing Construction Boilerhouse (CBH).

Approval of this request will bring the total to date funding to $40,463k including contingency of $[redacted] The total project is currently estimated to cost $45,607k ([redacted]). The new AHS Available for Service is currently planned on or before Apr 1st, 2015; prior to the 2015 Station Vacuum Building Outage (VBO) planned to start on Apr 3rd, 2015, to provide steam for TRF processes and heating to the station.

The business objective of this Regulatory project is to provide a source of reliable back-up steam to the Darlington Nuclear Generating Station (DNGS) main heating steam header to support irregular operating conditions in the event when all four turbine units are shut down in the winter to mitigate potential major equipment damage due to freezing. This will be achieved by replacing the existing original Construction Boilerhouse (CBH) with a new facility that can, in the event of a four unit shutdown, provide reliable back-up steam at a sufficient capacity to provide the required calculated equivalency (110,000 kg/hr) of steam lost from the turbine units. This back-up steam will contribute significantly to maintaining the temperature inside the Powerhouse and Tritium Removal Facility/Heavy Water Management Building (TRF/HWMB) above 10°C to prevent impairment of essential systems due to freezing.

The Investment Type of this Project is Regulatory to mitigate the concerns found in a Regulatory Action Request. A long term action plan to address the legacy issues is in place, of which this project is a key component with an objective of determining and implementing the most viable alternative to the current CBH.

The previous Full Definition Release BCS funded the modification planning and detailed engineering of the new AHS Boilerhouse, and preparation and submittal of this Partial Execution Release BCS.

This Partial Execution Release BCS will fund the engineering, procurement and construction of the new AHS Boilerhouse, and preparation and submittal of the Full Execution Release BCS. The Full Execution Release BCS, scheduled for Q1 of 2014, will fund subsequent demolition of the existing CBH, and close-out of the project. Estimated completion date for project close-out is Dec 30th, 2016.

This project is categorized as an ongoing operational support Campus Plan project required to meet the additional extended Darlington station life. The project funding will be accommodated within the Darlington Refurbishment Infrastructure Program. The on-going operating costs will be funded from Darlington station OM&A.

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*Associated with OPG-STD-0076, Developing and Documenting Business Cases

# Type 3 Business Case Summary

| **Project Cash Flows** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| k$ | **LTD** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **Future** | **Total** |
| Currently Released | 1,429 | 2,677 | 3,330 | | | | | | 7,436 |
| Requested Now | - | (1,033) | 10,762 | 23,298 | | | | | 33,027 |
| Future Required | - | | | 2,317 | 2,625 | 202 | | | 5,144 |
| **Total Project Cost** | 1,429 | 1,644 | 14,092 | 25,615 | 2,625 | 202 | | | 45,607 |
| Ongoing Costs | - | | | | | | | | |
| **Grand Total** | 1,429 | 1,644 | 14,092 | 25,615 | 2,625 | 202 | | | 45,607 |

| | | | |
|---|---|---|---|
| **Estimate Class:** | Class 3 | **Estimate at Completion:** | $ 39,056 k |
| **NPV:** | $ (29,490) k | **OAR Approval Amount:** | $ 45,607 k |

**Additional Information on Project Cash Flows (optional):**

Grand Total does not include ongoing operating costs (Darlington Station OM&A).

| **Approvals** | | | |
|---|---|---|---|
| | **Signature** | **Comments** | **Date** |
| This BCS represents the best option to meet the validated business need in a cost effective manner. | | | |
| **Recommended by:**<br>Brian Duncan<br>SVP, Darlington<br>Project Sponsor | | None | Oct 29/2012 |
| I concur with the business decision as documented in this BCS. | | | |
| **Finance Approval:**<br>Donn Hanbidge<br>Chief Financial Officer<br>Position per OPG-STD-0076 | | | Nov 9/12 |
| I confirm this project will address the business need, is of sufficient priority to proceed, and provides value for money. | | | |
| **Approved by:**<br>Tom Mitchell<br>President and CEO<br>Position per OAR, per OAR 1.1 | | | 12 NOV 12 |

# Type 3 Business Case Summary

Final Security Classification of the BCS: **OPG Confidential**

## Business Case Summary

**Part A: Business Need**

**Business Need:**

Under normal or abnormal operating conditions, the temperature inside the DNGS Powerhouse, TRF/HWM Building and other support buildings is required to be maintained, to prevent freezing. This is achieved using the existing heating steam system and local electrical heating equipment. Section 11.3.1 of the Darlington Safety Report, requires that a system be in place to prevent equipment and line freezing in the event of a design-basis four unit shutdown in the winter.

The current approach is to use the Construction Boilerhouse to provide back-up heating steam. The design basis for the Boilerhouse is to provide sufficient heating steam to maintain the station above 10°C when all operating units are shutdown. This project is not a reaction to post-Fukushima planning.

The current Construction Boilerhouse (CBH) facility was originally placed in service at the time of site construction in the early 1980's. This existing Boilerhouse has a total capacity of supplying up to approximately 45,000 kg/hr steam. The oil-fired boilers are used infrequently and were obtained at the time from other former Ontario Hydro construction projects. Electric boilers are also incorporated and provide the majority of the steam supply. The boilers and related equipment have received only limited and intermittent maintenance. The condition of the remaining systems, structures, and components has been assessed under Component Condition Assessments (CCA's). The piping and pipe supports require immediate field work. Other components require attention within the next 1-5 years.

The current CBH facility at Darlington cannot continue to provide this capability because:

- It is past its useful end of life.
- It does not have sufficient installed capacity.
- The current building and oil feeder piping does not meet the current code requirements.
- It was never designed as a permanent system or structure hence it is costly to maintain (foundation upgrades, pipe maintenance in pits, etc.)
- It does not meet the reliability requirements of an unavailability target of $1 \times 10^{-2}$.

Major activities and deliverables completed under the November 2010 Developmental BCS Release include:

1. A Gap Analysis Report was issued to determine whether the previous recommendation of constructing a new Auxiliary Heating Steam Facility was still feasible when the new requirements that were identified in the GOTHIC Analysis and revised Project Charter were considered.
2. Design Requirements were revised to specify the technical requirements for new AHS system taking into consideration future uses of heating steam such as the new Water Treatment Plant and D2O Storage Facility.
3. Black Start Option Benefit Cost Analysis and Economic Risk Assessment.
4. New AHS Nuclear East Facilities/DNGS Operations & Maintenance system responsibility memo.
5. Front End Planning, Project Execution Plan (PEP), and preparation of Developmental Release BCS.

Major activities and deliverables completed under the October 2011 Developmental BCS Release include:

6. Completed Civil, Mechanical, and Electrical ground scanning and drawing review of new AHS proposed site.
7. Completed Preliminary Geotechnical Analysis at the building site.
8. Completed a GOTHIC Analysis of the previously omitted site facilities to identify areas of vulnerability that will remain after implementation of this project. Identified vulnerable areas in both commissioned GOTHIC Analysis reports may still require some type of temporary or permanent mitigation to be implemented for provision of supplementary heat in order to prevent equipment and line freezing in the event of a design-basis four unit shutdown in the winter; however, mitigating measures are not included in this project's scope.
9. Performed ultrasonic thickness condition assessment/inspection of the existing steam/condensate piping located in Unit 1 and Unit 3 to evaluate whether it will reach station EOL in 2055.
10. Prepared and issued EPC RFP, evaluated submitted Proposals, negotiated and selected successful proponent.
11. Front End Planning, Project Execution Plan (PEP), and preparation of Full Definition Release BCS.

Major activities and deliverables planned for the Sep 2012 Full Definition BCS Release include:

12. Award EPC contract to successful ES MSA vendor for new AHS Boilerhouse.
13. Complete Modification Planning and Detailed Design for new AHS Boilerhouse.
14. Complete Geotechnical Investigation at the building site for new AHS Boilerhouse.
15. Identify Long Lead material items for new AHS Boilerhouse.
16. Front End Planning, Project Execution Plan (PEP), and preparation of Partial Execution Release BCS.

**Part B: Preferred Alternative**

**Description of Preferred Alternative: Construct New AHS Facility**

This option is recommended. The new AHS system shall be designed to an unavailability target of $1 \times 10^{-2}$, as well as a required heating steam rate of 110,000 kg/hr as specified in the Design Requirements. A quantity of two oil fired, water tube boilers are considered the best selection for boilers of this size and capacity. The total on-going operating costs are currently estimated at $350k per year. This on-going operating cost is not incremental, and is equal to the current operating costs of the CBH.

The Scope of Work proposed under this Partial Execution Release BCS is summarized below:

- New AHS Boilerhouse:
    - *EPC Contract Phase 2 Release Deliverable:*
        - Site preparation – Relocate and/or mitigate affected buried services in Owner Only construction island.
    - *EPC Contract Phase 3 Release Deliverables:*
        - Procure all materials,
        - Install AHS Facility and Building Services including tie-ins,
        - Install AHS Process and ancillaries,
        - Install Station System tie-ins, and
        - Commission AHS Facility and Process.
        - AFS for new AHS Facility and Process.
- Preparation and issuance of EPC Request For Proposal, and evaluation of submitted Proposals for Demolition of existing Construction Boilerhouse (CBH).
- Front End Planning, preparation of Full Execution Release BCS, and Project Execution Plan (PEP)

The priority of the project is tied to the next station Vacuum Building Outage and the results of the CCAs. The Charter stated expected objective is that the AHS shall be Available for Service prior to the next station Vacuum Building outage in April 2015. The strategy to maintain the existing Construction Boilerhouse as identified in the CCAs shall take into consideration the schedule for completion of the new AHS, to minimize the required maintenance work in the existing boilerhouse.

| **Deliverables:** | **Associated Milestones (if any):** | **Target Date:** |
|---|---|---|
| ***This Release:*** | ***This Release:*** | ***This Release:*** |
| New AHS - Modification Planning Complete | New AHS-Prelim Design Complete | Apr 16th, 2013 |
| New AHS - Long Lead Items Procurement Initiated | New AHS-LLM. Items PO Awarded | Jun 3rd, 2013 |
| New AHS - Detailed Engineering Complete | New AHS-Detailed Eng Complete | Oct 22nd, 2013 |
| New AHS - Installation and Comm. Planning Complete | New AHS-Start of Construction | Jan 23rd, 2014 |
| Full Execution Release BCS OAR Approved | Full BCS OAR Approved | Apr 30th, 2014 |
| New AHS - Installation and Commissioning Complete | New AHS-Final AFS | Apr 1st, 2015 |
| ***Future Releases:*** | ***Future Releases:*** | ***Future Releases:*** |
| Full Execution Release BCS OAR Approved | Demo CBH-EPC PO Awarded | May 30th, 2014 |
| Demo CBH - Modification Planning Complete | Demo CBH-Prelim Eng Complete | Aug 29th, 2014 |
| Demo CBH - Detailed Engineering Complete | Demo CBH-Detailed Eng Complete | Feb 13th, 2015 |
| Demo CBH - Demolition Planning Complete | Demo CBH-Start of Demolition | Aug 14th, 2015 |
| Demo CBH - Demolition Complete | Demo CBH-Final AFS | Dec 31st, 2015 |
| Plan Complete | Plan Complete | Dec 30th, 2016 |

## Part C: Other Alternatives

### Base Case: Status Quo – No Project

The option of Status Quo (Do Nothing) is not recommended. The existing Construction Boilerhouse does not meet a unavailability target of $1 \times 10^{-2}$. Additionally, the condition of the systems, structures and components has been assessed under CCA's which indicate that the piping and pipe supports require immediate field work. Other components require attention within the next 1-5 years. Furthermore, the existing boilerhouse only supplies 45,000 kg/hr steam, while the new Design Requirements indicate the back-up steam required is 110,000 kg/hr.

### Alternative 2: Delay Work – Delay Construction of New AHS Facility

This option is not recommended. The priority of the project is tied to the next station Vacuum Building Outage and the results of the CCAs. The project is required to be completed prior to the next station Vacuum Building Outage in 2015 to provide steam for TRF processes and heating to the station. In addition, delaying this project will result in significant OM&A costs (foundation upgrades, pipe maintenance in the pits, etc.) to the existing boiler house identified in the CCAs. This alternative was considered and eliminated, therefore, not included in the financial evaluation.

### Alternative 3: Boiler Rental

Boiler rental from an external company is not recommended. Two different options of Boiler rental were preliminarily examined; delivery of portable boilers during an emergency situation and on-site rental units.

The most critical disadvantage of delivery during an emergency situation is the high potential for significant delays before full capacity steam is available and provided for use in the plant, due to reliance on an external company and the logistics involved in mobilization, transportation to site, and set-up in an emergency situation. Estimates range from 24-36 hours before the boiler units reach site, plus additional connection time before steam will be available.

Further disadvantages include:

- High stresses induced in boiler components and structures due to difficulties in alignment during installation or sagging foundation over time,
- Portable boilers generally have horizontal cylindrical design to allow transportation on highways, and as a result, may require larger footprints than stationary boilers, and
- Capacity of a portable boiler is currently limited to about 34,000 kg/hr (for highway transportation), hence 3-4 units would be required to satisfy the required demand.

Although larger portable boiler units are available for rental and could be transported by freight for installation on-site, this alternative is also not desirable due to the following:

- The boilers would still require a small enclosure and heat tracing on the feed water piping for protection from the elements,
- Portable boilers and equipment on the skid would not be tagged to OPG standards. As such, a contract with a third party would be required for maintenance and operation (approximately $200-400K / year, budgetary), and
- Rental costs for the required size / number of portable units is estimated at approximately $180K/month ($2.2M / year), depending on the length of the contract.

Furthermore, similar to the recommended option, boiler rental will still require installation of steam, condensate, fuel and demineralized water tie-ins to the station and possibly installation of new electrical lines to support the rental units.

### Alternative 4: Construct New AHS Facility with Black Start Capability

This alternative was considered and eliminated. This would add approximately $20M to the total initial project costs of Alternative 1, plus an additional $0.75M in maintenance costs per year totalling ~ $45M from 2015 to 2055. Two independent assessments were obtained: an economic risk assessment performed internally by Nuclear Finance, and a Black Start economic assessment performed externally, which both concluded that it is not economically justified to include a Black Start capability into the new AHS. This alternative is, therefore, not included in the economic analysis of this BCS.

### Alternative 5: Refurbish Existing Construction Boilerhouse

Similar to the Base Case, Refurbishment of the existing Construction Boilerhouse is not recommended based on the fact it does not meet the minimum unavailability target, nor does it supply the required amount of steam per the Design Requirements.

### Alternative 6: Alternative Fuel Supplies

Alternative fuel supplies were examined for the AHS including electric, gas, and electric/oil combination fired boilers. These types of boiler facilities are not recommended. The cost to install new electric transmission lines and a switchyard, or natural gas transfer lines to site is in excess of $6M (per preliminary estimates). Dealing with two types of technology for combination boilers adds further logistical and cost concerns. Considering the Boilerhouse facility does not operate frequently, the additional costs associated with installation are not justified.

**Alternative 7: Co-Generation Plant**

A Co-Generation plant is not recommended due to the high initial investment cost of approximately $100M. There are also no corporate drivers to support this alternative at this time. Additionally, it is unlikely that real estate would be available at Darlington to site the co-generation plant in such a way that the steam transmission lines can be kept reasonably short. Delays due to likely need for an environmental assessment will make meeting the project schedule impossible.

**Part D: Project Cash Flows**

| k$ | LTD | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Future | Total |
|---|---|---|---|---|---|---|---|---|---|
| Currently Released | 1,429 | 2,677 | 3,330 | | | | | | 7,436 |
| Requested Now | - | (1,033) | 10,762 | 23,298 | | | | | 33,027 |
| Future Required | - | | | 2,317 | 2,625 | 202 | | | 5,144 |
| **Total Project Cost** | 1,429 | 1,644 | 14,092 | 25,615 | 2,625 | 202 | | | 45,607 |
| Ongoing Costs | - | | | | | | | | |
| **Grand Total** | 1,429 | 1,644 | 14,092 | 25,615 | 2,625 | 202 | | | 45,607 |

| | | | | | |
|---|---|---|---|---|---|
| **Estimate Class:** | Class 3 | **Estimate at Completion:** | $ 39,056 k | **OAR Approval Amount:** | $ 45,607 k |

**Additional Information on Project Cash Flows (optional):**

Grand Total does not include ongoing operating costs (Darlington Station OM&A).

**Part E: Financial Evaluation**

| k$ | Preferred Alternative - New AHS Facility | Alt 3 - Boiler Rental | Alt 5 - Refurb Boilerhouse | Alt 6 - Alternate Fuel | Alt 7 - Co-Gen Plant |
|---|---|---|---|---|---|
| **Project Cost** | (37,627) | (47,581) | (42,609) | (46,090) | (121,432) |
| **NPV (after tax)** | (29,490) | (46,654) | (34,574) | (35,993) | (89,217) |
| **Other (e.g., LUEC)** | N/A | N/A | N/A | N/A | N/A |

**Summary of Financial Model Key Assumptions (see Guidance on this Type 3 BCS Form):**

(1) Discount rate of 7%.

(2) Escalation rate of 2%.

(3) Interest rate of 5% on capital costs.

(4) Ongoing Operating & Maintenance Costs used for NPV calculations are based on Project high level estimates. Operating & Maintenance Costs that are not incremental were not included in the NPV calculations.

(5) The NPV values are after tax $2012.

(6) Project Costs include demolition costs.

**Part F: Qualitative Factors**

Another benefit associated with the project includes:

- Mitigate increased risk during refurbishment for reliable and sufficient heating steam in the event of a four unit outage, as there will be extended durations where two units are shutdown for scheduled refurbishment activities, effectively increasing the likelihood of a four unit outage. A Station Containment Outage (SCO) is currently scheduled for 2022 during refurbishment; therefore, the AHS will be required to provide steam for TRF processes and heating to the station during that time period.

**Part G: Risk Assessment**

| Risk Class | Description of Risk | Risk Management Strategy | Post-Mitigation | |
|---|---|---|---|---|
| | | | Probability | Impact |
| Cost | The Plant system tie-in assumptions stipulated in the SOW for Steam / Condensate / Demin Water / Fuel maybe determined to be inadequate when calculated volume/capacity is developed during detailed design. It is already known that the Steam line is inadequate for the new capacity, however, the final design configuration to provide the optimum routing cannot be determined during the conceptual phase of the project. | Accept: Assigned $3M Specific Contingency based on 3rd Party Estimates for postulated possible design alternatives | High | Medium |
| Scope | The pending revision to the ECC Risk Based Process to replace or include the existing FMOD process may introduce additional scope into the contract due to additional requirements that are not currently required per FMOD. | Accept | Medium | Medium |
| Schedule | When excavating for Building or Plant Systems unexpected buried services, and/or unidentified items could be discovered by Contractor. | Accept: EPC Contractor to engage FE immediately upon discovery of any buried services / unidentified items not marked in the field or shown on site drawings/plans. | Medium | High |
| Resources | OPG resources (Ops, Maint, Design, FE, CMO, Security, RP, etc.) unavailable to provide support during entire ~ 2 year execution period. | Mitigate:<br>1. Communicate and engage affected OPG work groups well in advance to ensure support will be available during the required time.<br>2. Schedule tasks where possible when resources will be available. (i.e. outside of planned outages) | Low | High |
| Quality/ Performance | QS processes to be performed by FE for EPC vendor's is new role for OPG. Issues may arise due to unfamiliarity with the process and expectations. Procedure may be revised to address identified issues. | Accept: Current assumption is oversight will be in accordance with OPG's Contractor Quality Surveillance Procedure. | Medium | Medium |
| Technical | Potential for issues pertaining to changes in code requirements at the tie-ins where new piping connects to old existing piping. | Accept: Reconcile any identified code issues as required during detailed design. | High | Medium |

| | | | | |
|---|---|---|---|---|
| Scope | As a result of the Sewage Treatment Plant being decommissioned, the new AHS may not be able to discharge (blowdown & condensate) to the municipality and may need to run piping and tie-in to inactive drainage (inside the Station) or Condenser Cooling Water (CCW) resulting in additional design/scope/schedule impact. | Accept: EPC Contractor to establish during modification planning and detail design stages requirements to comply with MOE Environmental Compliance Approval(s)/Condition(s). | Medium | High |
| Schedule | The Installation / Commissioning of the AHS is not completed before the start of the 2015 Station Vacuum Building Outage AFS. (no later than Mar 31, 2015) | Mitigate: Existing CBH to remain in-service until after new AHS has been successfully AFS'd / turned over. | Medium | High |
| Scope/Cost | Cost of EPC contract increases due to discovery work or work not captured in Scope of Work or contract assumptions. | Accept: Discovery issues/items to be resolved via Change Management Process as necessary. | Medium | High |
| Schedule | Excavation under the Security Fence - Potential for a variety of issues (including voids) and delays when routing the steam, condensate, demin, and fuel under the Security Fence. | Accept:<br>1. Incorporate OPEX to help mitigate potential issues to extent possible.<br>2. Allow adequate time to resolve any discovery issues in installation schedule. | Medium | High |
| Scope | Due to unknown conditions (below grade) extra work might be required to repair or support the existing underground service tie-ins. | Accept: EPC Contractor to identify / resolve Potential Issues regarding tie-in connections during Detailed Design. If deemed additional scope it will be resolved via Change Management Process (CCA) as necessary. | Medium | Medium |
| Schedule | Improper storage of materials or equipment onsite/offsite by contractor may cause damage either physically or by exposure to harsh environmental conditions. | Transfer:<br>1. Contractors responsibility per ES MSA.<br>2. Prior to OPG acceptance (AFS) all equipment must be in good working condition.<br>3. Once AFSd, 2 year warranty in effect per ES MSA agreement. In the event of failure, 2 year warranty clock restarts again upon replacement / repair. | Low | Medium |

| | | | | |
|---|---|---|---|---|
| Schedule | Delays in material procurement (by contractor, subcontractor and/or OPG) causing installation delays. This includes qualified vendors being on the OPG ASL for EPC contracts. | Transfer:<br>1. Contractors responsibility per ES MSA.<br>2. EPC Contractor to develop a Procurement Plan which will include Long Lead Items and equipment procurement specifications, during the modification planning phase.<br>3. Contractor to ensure materials are ordered well in advance to support implementation schedule. | Low | Medium |
| Schedule | Delays to project schedule due to regulatory approvals taking longer than required. | Mitigate:<br>1. Initiate communications with regulatory agencies in advance of formal submissions to seek agreement in principle with proposed pending changes.<br>2. Stage EC releases to provide adequate time for regulatory agencies to review and respond to submissions to align and meet project schedule. | Low | Medium |
| Schedule | Weather conditions cause unforeseen delays during installation. | Mitigate:<br>1. EPC Contractor to factor Heat Stress and "average" Weather Conditions into schedule.<br>2. EPC Contractor to factor potential dewatering activities into schedule. | Low | Medium |
| Technical | Final Specifications for interfacing Projects do not meet the AHS demand. (i.e. New Water Treatment Plant, Domestic Water Upgrade, or site Electrical Upgrade) | Mitigate: Co-ordinate with interfacing projects to ensure the needs of the AHS are clearly identified and incorporated. | Low | Medium |
| Resources | EPC Contractor does not resource Project adequately resulting in delays. | Transfer:<br>1. OPG to award contract as early as practical and avoid to the extent possible any subsequent delays as phased work is released to contractor.<br>2. Contractor is responsible to work with Union Halls and staff project appropriately to support execution schedule. | Medium | Medium |

**Additional Risk Analysis:**

See Risk Management Plan in the Project Execution Plan for more detail.

**Part H: Post Implementation Review (PIR) Plan**

| Type of PIR | Target Project In Service Date | Target PIR Completion Date |
|---|---|---|
| Simplified | 2015-04-01 | 2016-12-30 |

| Measurable Parameter | Current Baseline | Target Result | How will it be measured? | Who will measure it? (person/group) |
|---|---|---|---|---|
| Provide heating steam flow rate of 110,000 kg/hr as per Design Requirements. | 45,000 kg/hr | 110,000 kg/hr | Acceptance of commissioning results and subsequent successful AFS of new AHS. | Performance Engineering /Operations & Maintenance / Project Design |
| Identify all susceptible equipment and components vulnerable to freezing in the vulnerable areas identified by the GOTHIC analysis. | Current revision of GOTHIC analysis identifies all areas of the plant which are vulnerable, but does not identify the susceptible equipment and components in those areas. | Identify all process equipment vulnerable to freezing and complete walkdowns and document susceptible equipment and components in these areas. | Acceptance of revised GOTHIC analysis report and subsequent identification of affected equipment in vulnerable areas before AFS. | Projects Design |
| Reliability requirements satisfied. | Does not meet requirements. | 1 x $10^{-2}$ | Design Acceptance of vendor submitted analysis report. | Projects Design |

**Part I: Definitions and Acronyms**

| | |
|---|---|
| AFS | Available for Service |
| AHS | Auxiliary Heating System |
| ASL | Approved Suppliers List |
| BCS | Business Case Summary |
| CBH | Construction Boiler House |
| CCA | Component Condition Assessment |
| CMO | Contract Management Office |
| COMS | Constructability, Operability, Maintainability, Safety |
| DNGS | Darlington Nuclear Generating Station |
| DR | Design Requirements |
| EC | Engineering Change |
| ECC | Engineering Change Control |
| EOL | End of Life |
| EPC | Engineer, Procure, Construct |
| ES MSA | Extended Services Master Service Agreement |
| FE | Field Engineering |
| FMOD | Facilities Modification |
| GOTHIC | Generation of Thermal Hydraulic Information for Containments |
| HWMB | Heavy Water Management Building |
| JSA | Job Safety Analysis |
| MOE | Ministry of Environment |
| OPEX | Operating Experience |
| OPG | Ontario Power Generation |
| OPS | Operations |
| PDRI | Project Definition Rating Index |
| PEP | Project Execution Plan |
| PSVS | Power House Steam Venting System |
| QS | Quality Surveillance |
| RAB | Reactor Auxiliary Bay |
| RFP | Request for Proposal |
| RP | Radiation Protection |
| SOW | Scope of Work |
| TH | Turbine Hall |
| TRF | Tritium Removal Facility |
| VBO | Vacuum Building Outage |

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**<u>For Internal Project Cost Control</u>**

# Type 3 Business Case Summary

**Appendix A: Summary of Estimate**

| | | | |
|---|---|---|---|
| **Project Number:** | 16-34000 | **Facility:** | Darlington |
| **Project Title:** | Darlington Auxiliary Heating System Project | | |

**Estimated Cost in k$**

| | LTD | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Future | Total | % |
|---|---|---|---|---|---|---|---|---|---|---|
| **OPG Project Management & Support** | 804 | 252 | 856 | 970 | 715 | 132 | - | - | 3,729 | 8% |
| **OPG Engineering** | 378 | 125 | 199 | 181 | 126 | 52 | - | - | 1,061 | 2% |
| **Permanent Materials** | - | - | 3,429 | 6,650 | 74 | - | - | - | 10,153 | 22% |
| **Design and Construction (Contracts)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Consultants** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Other Contracts/Costs** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Interest** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Subtotal** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Contingency** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Total** | **1,429** | **1,644** | **14,092** | **25,615** | **2,625** | **202** | **-** | **-** | **45,607** | **-** |
| **Removal Costs Included** | - | - | 44 | 414 | 1,396 | 149 | - | - | **2,003** | **4%** |

**Notes**

| | | | |
|---|---|---|---|
| **Project Start Date** | 2006-03-23 | **Project Completion or In-Service Date** | 2015-04-01 |
| **Interest Rate** | 5.0% | **Escalation Rate** | 2.0% |
| **Definition Cost Included** | $ 45,607 k | **Estimate at Completion** | $39,056 k |

| **Prepared by:** | | **Approved by:** | |
|---|---|---|---|
| | 2012-10-29 | | 2012-10-29 |
| Ricardo Fiorini<br>Project Manager,<br>Darlington Projects | YYYY-MM-DD | George Makdessi<br>Manager,<br>Darlington Projects | YYYY-MM-DD |

**Appendix B: Comparison of Total Project Estimates**

| Phase | Release | Date (YYYY-MM-DD) | Total Project Estimate in k$ (by year including contingency) | | | | | | Later | Total Project Estimate |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | | |
| Initiation | Developmental | 2006-03-23 | 23,505 | | | | | | | 23,505 |
| Initiation | Developmental | 2010-11-08 | 4,627 | 3,062 | 13,122 | 11,989 | 13,043 | 251 | | 46,094 |
| Definition | Developmental | 2011-10-04 | 1,521 | 1,130 | 10,537 | 19,018 | 5,946 | 464 | | 38,616 |
| Definition | Full | 2012-09-17 | 1,429 | 2,677 | 14,425 | 23,821 | 3,023 | 190 | | 45,565 |
| Execution | Partial | 2012-11-01 | 1,429 | 1,644 | 14,092 | 25,615 | 2,625 | 202 | | 45,607 |

**Project Variance Analysis**

**Estimated Cost in k$**

| k$ | LTD | Total Project | | Variance | Comments |
|---|---|---|---|---|---|
| | | Last BCS | This BCS | | |
| **OPG Project Management & Support** | 804 | 3,480 | 3,729 | 249 | Last BCS slightly underestimated FTEs required for supporting groups. Resources were increased slightly to account for correct FTEs. |
| **OPG Engineering** | 378 | 1,112 | 1,061 | (51) | Last BCS slightly overestimated FTEs required for OPG Engineering. Resources were decreased slightly to account for correct FTEs. |
| **Permanent Materials** | - | 9,834 | 10,153 | 319 | Cost of permanent materials increased slightly due to the change in EPC contractor selection. |
| **Design and Construction (Contracts)** | [redacted] | [redacted] | [redacted] | [redacted] | New AHS EPC contract costs increased ($804k) due to a change to a better qualified EPC contractor per bid evaluation process.<br>Cost estimate of demolition EPC contract was reduced by $800k to account for reduction in demolition scope.<br>Last BCS included cost of Geotechnical Investigation in the 'Other Contracts/Costs' section. |
| **Consultants** | [redacted] | [redacted] | [redacted] | [redacted] | No Change. |
| **Other Contracts/Costs** | [redacted] | [redacted] | [redacted] | [redacted] | Geotechnical Investigation costs moved to 'Design and Construction (Contracts)'. |
| **Interest** | [redacted] | [redacted] | [redacted] | [redacted] | Interest decreased slightly due to change in project costs and cashflows. |
| **Subtotal** | [redacted] | [redacted] | [redacted] | [redacted] | |
| Contingency | [redacted] | [redacted] | [redacted] | [redacted] | Contingency calculated using Extensive Risk Management Strategy (Monte Carlo Analysis) for Partial Execution Release.<br>Contingency calculated using Minor Risk Management Strategy (Qualitative Risk Analysis) for Full Execution Release (Future). See Risk Management Plan in PEP. |
| **Total** | **1,429** | **45,565** | **45,607** | **42** | |
| Removal Costs Included | - | 2,664 | 2,003 | (661) | Removal costs decreased due to reduction in demolition scope (i.e. no switchyard removal). |

## Appendix C: Financial Evaluation Assumptions

Key assumptions used in the financial model of the Project are (complete relevant assumptions only):

**Project Cost:**

(1) Installation, and commissioning estimates do not change significantly from Phase 1 of EPC contract to Phase 2 and 3 of EPC contract outside of allotted contingency.

(2) Detailed design, material, installation, and commissioning estimates do not change significantly from 3rd party estimates when existing CBH Demo EPC RFP is issued.

(3) Sufficient funds in the portfolio.

**Financial:**

(1) Discount Rate of 7%.

(2) Escalation rate of 2%.

(3) Interest rate of 5% on Capital costs.

(4) Ongoing Operating & Maintenance Costs used for NPV calculations are based on Project high level estimates.

**Project Life:**

(1) New AHS system process equipment shall be designed for a minimum life of 25 years.

(2) The new Boilerhouse building, structures, and services shall be designed for a minimum life of 35 years.

**Energy Production:**

(1) The AHS system shall be designed to be available for a maximum of 6 days after full steam output is achieved.

(2) The new AHS system shall be designed for unavailability target of $1 \times 10^{-2}$.

**Operating Cost:**

(1) The total on-going operating costs for the new AHS Boilerhouse are currently estimated at $350k per year. These costs were not included in the financial evaluation as they are not incremental operating costs.

**Other:**

(1) The new AHS will remain classified as a non-Safety Related System.

Attach further detail as appropriate from the Financial Evaluation spreadsheet.

(N/A)

## Appendix D: References

D-BCS-00120.3-10013 – Developmental BCS

D-BCS-00120.3-10002 – Full Definition BCS

# Type 3 Business Case Summary

**This Guidance section should be deleted prior to submission of the BCS.**

## Guidance for Completing this Type 3 Form:

**Always use the latest revision of the Form!**
Verify this is the latest revision through PowerSearch,
or Finance BCS Toolkit intranet website.

### Final Security Classification

Determine the Final Security Classification of the BCS from the drop-down list before both the Executive Summary and Recommendations and Part A. Refer to OPG-STD-0030 Classification, Protection and Release of Information.

### Executive Summary and Recommendations

*Records File Information*

Refer to OPG-PROC-0019, Records and Document Management for the requirements and expectations of record filing after the BCS is submitted.

The SCI used for record filing should be:

- *00120.3* for Nuclear BCSs.
- *08707.021* for BCSs of all other business units and corporate groups.

Submitted BCSs shall also be filed according to local BU governance, which may require different SCIs.

*Project Overview*

State the following:

- What needs to be done and why it needs to be done.
- When the investment/project will be completed.
- Key business objectives.
- Expected benefits of the investment/project.
- Whether the investment/project is within the original scope as specified in the approved Business Plan and/or Life Cycle Plan.
- Brief history of previous releases.
- Level of confidence for current request.
- If critical to the decision, any constraints on the investment/project or its timing.

*Project Cash Flows*

This table in the Executive Summary and Recommendations section is the same as the table in Part D: Project Cash Flows. See guidance for Part D: Project Cash Flow.

*Approvals*

Provide the title and name of the individuals making the three required signatures: the Project Sponsor, the individual providing Finance Approval, and the Approver of the BCS per the OAR. The Comments cell is to allow brief hand-written comments. For example, "see comment on Part D", which would refer to a hand-written comment later in the BCS document. These comments would be minor in nature; otherwise a reviewer would require revisions to the BCS before signing the document.

# Type 3 Business Case Summary

## Business Case Summary

### Part A: Business Need

This section describes the business needs or opportunities that gave rise to the investment. It provides background and context for the investment including: the investment's purpose, what's driving the investment, why the investment needs to be addressed now, what are the impacts of not proceeding, key assumptions, identification of any subsequent commitments or obligations, and the benefits or constraints that the investment will create. Provide studies, experience or lessons learned from similar investments, if available. If this submission relates to a subsequent approval, provide a quick overview of investment history.

If the investment is a subset of a program, or if the issue to be addressed is symptomatic of a broader issue that requires additional response, provide the context and identify the related response, whether planned or anticipated.

### Part B: Preferred Alternative

This section describes expected business results and objectives, including resourcing requirements, when the investment will be completed, and any major milestones. The proposal section must put the investment into the proper context by providing the link between the investment and the business strategy for the asset and/or other planned investments in that asset.

Describe the link between this investment and business strategy or other investments. Disclose if the resourcing is in place. Alternatively, if the investment is not in the business plan, or if the scope has changed relative to the Business Plan, reasons for the change(s) must be provided.

State the expected benefits and what is being delivered, without specifying vendor name(s). Describe briefly project execution strategy, regulatory approvals, third party agreements, project management, and basis for the cost and schedule contingencies, if applicable. Highlight any constraints on the investment or on its timing, and any constraints or obligations created by the investment.

*Deliverables*

In the Deliverables section, list the project deliverables and target completion dates, including associated milestones (such as unit in-service dates and external or regulatory milestones).

### Part C: Other Alternatives

This section describes viable alternatives considered, including associated risks. At minimum, include a Base Case: Status Quo – No Project. Other alternatives may include:

- Deferring the project.
- Different means to meet the same business need.
- Completing partial scope.
- Alternatives with additional scope.

### Part D: Project Cash Flows

The table in Part D: Project Cash Flows is very similar to the table under Project Cash Flows in the Executive Summary and Recommendations section.

This table provides a yearly breakdown of estimated project costs, including amounts currently released from earlier BCSs if applicable, the new amounts being requested now in this BCS, and estimated future requirements not currently requested. Contingency shall be included in these amounts.

The new amounts being requested are for actual work to be completed and for any costs that will be committed to through that work. For example, if an equipment purchase is bundled with a maintenance contract for a committed period, the committed payments under the maintenance contract must be included in the current request. Ongoing Costs include any costs related to the investment that would not be part of the project budget, including ongoing incremental operating costs, and acquisition of inventory.

The Future column is the sum of expected future cash flows beyond the last year shown in the table.

*Estimate Class*

Estimate Class is a cost estimate classification system developed by the Association for the Advancement of Cost Engineering International (AACE) which defines the estimate "quality" based on the input information used and the project's stage of development. AACE uses five estimate classes with Class 5 being the least accurate, and Class 1 being the most accurate.

| **Estimate Class** | **Class 5** | **Class 4** | **Class 3** | **Class 2** | **Class 1** |
|---|---|---|---|---|---|
| **Phase** | **Identification** | **Initiation** | **Definition** | **Execution** | **Execution** |
| **Level of Project Definition (%)** | 0% to 2 | 1 to 15 | 10 to 40 | 30 to 75 | 65 to 100 |
| **Expected Accuracy Range (%)** | -50 to +100 | -30 to +50 | -20 to +30 | -15 to +20 | -10 to +15 |

*OAR Approval Amount*

For BCSs up to and including Definition Phase work, the OAR Approval Amount is the cumulative total actual and committed cost to date, not the estimated total investment/project cost. For Execution Phase BCSs or BCSs that cover multiple phases including Execution, the OAR Approval Amount is the estimated total investment/project cost, including cumulative cost to date.

*Additional Information on Project Cash Flows (optional)*

Relevant information such as the delta between approved business plan cash flows and requested release may be entered into this open-field table cell.

**Part E: Financial Evaluation**

This section describes and compares the key alternatives considered. Only the most relevant alternatives shall be listed in this table for comparison. The analysis includes financial evaluations, economic analysis, and comparisons of the alternatives based on total project cost, after-tax NPV, and any other financial metric deemed appropriate by the project sponsor (e.g., IRR, discounted payback, etc.) The BCS Financial Evaluation Model is available on the Finance website and is updated periodically to help facilitate financial analysis. Attach further detail as appropriate from the Financial Evaluation spreadsheet.

*Summary of Financial Model Key Assumptions*

List key assumptions used in the Financial Evaluation. For Part E, provide a brief summary of the most important assumptions that are listed in Appendix C.

**Part F: Qualitative Factors**

Qualitative factors gained (or lost) from the investment and how an initial specification will be measured within the post implementation review (to the extent feasible). Qualitative factors could include: sustainable energy development impacts; community, government, and customer relations; staff relations issues, technical or operational considerations, reliability, health and safety issues, and other intangibles.

**Part G: Risk Assessment**

This section identifies the risks associated with the investment and the plans to manage or mitigate these risks. Refer to OPG-STD-0062, Project Risk Management Standard and local business unit standards for guidance on completing and documenting risk assessments. Each BU can add risk areas specific to its business.

Extra Risk Classes may be added by changing "Other" to a specific risk class and/or inserting extra rows to the table.

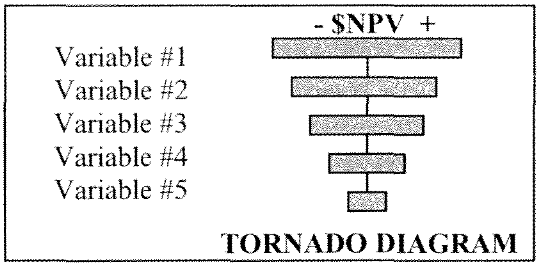
The Risk Analysis section discusses, as appropriate for the project, quantitative risk factors that relate to the project financial evaluation, including considerations such as:

- Present and discuss material impacts/consequences of variations in the basic assumptions, e.g., price of electricity used for revenue, sales forecast, service life, etc. Discuss likelihood of occurrence.

- Based on risks identified and mitigation measures implemented, indicate whether the financial analysis completed for the recommended alternative includes the contingency required for OPG residual risks, and their impact on the estimated in-service date.

- The extent of the risk assessment and the risk analysis techniques employed should be commensurate with the magnitude of the cash flows and the degree of uncertainty associated with the critical assumptions upon which the investment is based.

- For Major Projects, the risk analysis section will typically include sensitivities of the investment to various risk factors or scenarios, and a discussion of their likelihood of occurrence. A convenient way of presenting the results of the risk assessment on the variability of the NPV to changes in the critical variable is to include a graph or tornado diagram as shown below.



- For larger investments, more advanced risk analysis techniques such as Monte Carlo may be suitable. These techniques require analysts with appropriate training; contact your local Finance support to discuss applicability and to arrange Finance analytical support if required. The limitations of Monte Carlo or any other risk assessment technique must be considered in their application, and require a time commitment from the project team and stakeholders to develop and estimate model inputs.

### Part H: Post Implementation Review (PIR) Plan

PIR plan is a succinct description of the project benefits using measurable parameters. The PIR plan should clearly specify what is to be measured, who is responsible for measuring it, and when the measurement should take place, along with any requirements for establishing pre-project baseline information for comparison purposes.

Extra PIR metrics may be added by inserting extra rows to the table.

The PIR plan should contain the following five main elements:

- What: Key deliverables or benefits of the project clearly defined in measurable parameters, including a clear description of the reference or baseline from which the incremental benefits or changes due to the project are to be measured.

- How: A brief description of how each parameter is going to be measured.

- Who: The name of the group, department, or individual that will be measuring the benefits.

- When: When the measurement of the benefits will take place.

In addition, the Project Sponsor and key stakeholders may specify other items such as the types of lessons learned and recommendations to be captured during the execution of the PIR.

### Part I: Definitions and Acronyms

Define key technical terms and list acronyms to assist reviewers of the document.

### Appendix A: Summary of Estimate

**Note:** All content from Appendix A onwards, including this Guidance section, contains a level of detail that is intended for OPG internal use only and should be removed before a copy of a BCS is released to an external party.

To assist the reviewer in understanding the cost estimate in the BCS, this table provides a breakdown of various cost components by year, with explanatory notes as appropriate.

**Note:** The label "Project Completion or In-Service Date" is intended to provide flexibility for projects that do not have a specific "In-Service Date", such as engineering studies in future decisions or for future regulatory documents.

### Appendix B: Comparison of Total Project Estimates and Project Variance Analysis

This section provides the history of past releases and their associated estimates, with explanations of changes as appropriate.

### Appendix C: Financial Evaluation Assumptions

This section is intended to provide a reviewer with an overall understanding of the key assumptions used in the financial evaluation, to help a reviewer confirm that relevant drivers and appropriate assumptions were used in the analysis. The main considerations in the economic evaluation of the alternatives are outlined below:

*Cost and Schedule Estimates*

The work breakdown structure (WBS) of the project usually provides detailed information on the cost of the project and should be referred to while estimating the costs and schedule. Best practices in project cost and schedule estimating should be applied wherever possible including using lessons from similar experiences and benchmarks. Requests for quotations from competitive sources are another option to obtain detailed estimates. Schedule and cost estimates must obtain stakeholders' inputs and be reviewed by the key stakeholders of the project before being finalized.

*Taxes*

All investments must be assessed on an after-tax basis. Users will be required to properly classify the capital assets for Capital Cost Allowance (CCA) purposes. The financial evaluation model provided on the Finance website will compute the initial income tax impacts for most types of investments; the model also contains the latest CCA rates for most types of investments. For further information on CCA, sales taxes and tax shields, please contact your local Finance support group.

*Cost of Capital*

An appropriate cost of capital or discount rate must be used to ensure that an adequate return is provided to shareholders. For investments related to the manufacturing and processing of electricity for regulated nuclear and base-loaded hydroelectric facilities, the discount rate is generally lower than for unregulated facilities. This is partly due to regulated assets having a more predictable revenue stream, and hence lower risk than unregulated generation facilities.

For projects and business opportunities that are clearly outside of OPG's core business, or are not related to the manufacturing and processing of electricity, the project's cost of capital should be used, instead of OPG's cost of capital. Updated rates for OPG's core business are posted in the BCS Financial Evaluation Model. Contact Investment Planning for assistance.

*Revenue Forecasts*

The revenue forecast from generation assets must be based on the OPG System Economic Values (SEVs). The appropriate SEVs for the applicable time frame are selected based on the characteristics of the generation asset being evaluated (e.g., peaking vs. baseload). Contact your local Finance support group for further guidance on using SEVs.

### Appendix D: References

The reference documentation and attachments contain the detailed numbers, calculations, and any other analysis done probing the need and substantiating the justification for the investment. This documentation includes: cost estimates, financial evaluation sheets, risk assessment tables, modeling assumptions, project execution plan, technical studies, and any other specific studies related to the investment.

**Additional Attachments**

Additional documents be prepared as separate documents and enclosed with the BCS for reviews and approvals (e.g., multiple file attachments to e-mails).

The final signed version of the BCS may then be combined with all the attachments in a single PDF file.

# Hydro Thermal Operations 2013-15 Business Plan

May 16, 2013

**Frank Chiarotto, SVP Hydro Thermal Operations**

ONTARIO POWER GENERATION

# Hydro Thermal Operations Strategies & Key Deliverables

## 1. Operate and Maintain Hydro & Thermal Plants with Focus on Sustaining & Regulatory Work

- Safe and reliable plant operations through prudent maintenance and investment strategy with significant deferral/reductions of value enhancing and low risk work. Utilize a risk-based approach (ie, Plant Condition/Engineering Risk Assessments) for determining investment priorities
- Continue to strengthen and develop relationships with stakeholders to sustain continued operations at existing HTO facilities and [redacted]
- Maintain/improve excellent safety, environmental and reliability performance. Continue prudent investments and improvements in Dam and Public Safety program
- [redacted] commitments are met and value to OPG is maximized

## 2. Transform Hydro Thermal Operations into a Low Cost, Agile and Variable Business Model

- Complete implementation of BTS centre-led model, reductions, and initiatives
- Transition the business to a more flexible and cost variable model
- [redacted]
- Prepare OEB 2014/15 Cost of Service filing and Niagara Tunnel Prudency Review. Prepare for and implement Incentive Regulation as per OEB appropriate schedule
- Implement/operationalize Information Management Transformation project (SAP to Passport/Asset Suite)

# Hydro Thermal Operations Strategies & Key Deliverables (Cont'd)

## 3. Optimize Costs & Project Timing - Move Hydro Value Enhancing/Capacity Projects to Post 2016 Period and [redacted]

- Total plan over plan OM&A cost reduction of [redacted] ([redacted] in 2012, [redacted] in 2013 and [redacted] in 2014) achieved through:
  - [redacted] and deferral of lowest risk major overhaul and civil maintenance projects in the Hydro fleet ([redacted])
  - Absorption of labour escalation ([redacted]) through productivity improvements and work program reductions and optimization
  - Reductions in non-base labour and other costs of approximately [redacted] per year (eg, Society PSA reductions associated with reduced project portfolio, overtime savings on outages, non-essential travel reductions)
- Total plan over plan capital cost reduction of [redacted] during 2012 to 2014 period. HTO will execute the planned capital project portfolio for existing assets on budget and schedule (average [redacted] per year)

## 4. Grow the Business

- Provide Project Management support to ensure projects are safely delivered on time, budget and scope
- Support Corporate Business Development in new generation opportunities ([redacted] Ranney Falls, [redacted]
- [redacted]

# Planning Assumptions (2013 to 2015)

**Hydro**

- Focus on regulatory and sustaining work during planning period. Value enhancing projects (runner upgrades) deferred to post 2015 period
- Hydro major unit refurbishment and outage program aligned with Darlington refurbishment timing. Non-system impactive outages deferred to post 2016 period
- PGS Reservoir rehabilitation and full station outage deferred from 2014 to 2016/17 to mitigate Surplus Baseload Generation (SBG) spill losses
- Niagara Tunnel in-service mid-2013 (6 months early) and cost of $1.5B versus budget of $1.6B
- [redacted]

**Thermal**

- [redacted]

**General**

- HTO staff dedicated to the implementation of the IMT project funded by BAS (Capital – Execution Phase)
- Development projects entering Execution Phase in 2013 are included in the HTO Business Plan. Hydro Development/repowering projects in definition and concept phase, [redacted], are included in the Corporate Business Development plan
- Aboriginal past grievance provision/contingency will be funded by Stakeholder Relations ($5 M per yr)

# Hydro Thermal Operations Performance Summary

| | 2012 Actual | 2013 | 2014 | 2015 |
|---|---|---|---|---|
| **PRODUCTION** | | | | |
| **Capacity (MW)** | [redacted] | [redacted] | [redacted] | [redacted] |
| Hydro | 6,996 | 6,996 | 7,063 | 7,433 |
| Thermal | [redacted] | [redacted] | [redacted] | [redacted] |
| **Energy (TWh)** | [redacted] | [redacted] | [redacted] | [redacted] |
| Hydro | [redacted] | [redacted] | [redacted] | [redacted] |
| Thermal | [redacted] | [redacted] | [redacted] | [redacted] |
| **Hydro Availability (%)** | 91.2 | 91.6 | 92.6 | 91.2 |
| **Thermal Start Guarantee (%)** | [redacted] | [redacted] | [redacted] | [redacted] |
| **EFOR (OP) (%)** | [redacted] | [redacted] | [redacted] | [redacted] |
| **RESOURCES** | | | | |
| **Total OM&A ($M)** | [redacted] | [redacted] | [redacted] | [redacted] |
| Base OM&A ($M) | [redacted] | [redacted] | [redacted] | [redacted] |
| Project OM&A ($M) | [redacted] | [redacted] | [redacted] | [redacted] |
| **Total Capital ($M)** | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Niagara Tunnel ($M) | 231 | 184 | 0 | 0 |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Regular Staff** | [redacted] | [redacted] | [redacted] | [redacted] |

# Hydro Thermal Operations OM&A  Plan over Plan

| **OM&A ($M)** | **2012 Actual** | **2013** | **2014** | **2015** |
|---|---|---|---|---|
| **Approved 2012 OM&A Business Plan** | [redacted] | [redacted] | [redacted] | [redacted] |
| Business Transformation - Phase 1 Transfers to Corporate Groups | [redacted] | [redacted] | [redacted] | [redacted] |
| Corporate Labour Escalation Challenge (PWU, Society, & Management) | [redacted] | [redacted] | [redacted] | [redacted] |
| Labour Rate & Burden Changes (2013-2015) | [redacted] | [redacted] | [redacted] | [redacted] |
| **Revised 2013 OM&A Guideline** | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Non-Standard Projects Changes | [redacted] | [redacted] | [redacted] | [redacted] |
| Schedule Change (deferred, cancelled or advanced) | [redacted] | [redacted] | [redacted] | [redacted] |
| Scope Change | [redacted] | [redacted] | [redacted] | [redacted] |
| Cost Change (escalation and revised estimates) | [redacted] | [redacted] | [redacted] | [redacted] |
| New Project (from Plant Conditon Assessments) | [redacted] | [redacted] | [redacted] | [redacted] |
| Other | [redacted] | [redacted] | [redacted] | [redacted] |
| **2013 OM&A Submission** | [redacted] | [redacted] | [redacted] | [redacted] |
| **2013 OM&A Submission versus Revised 2013 OM&A Guideline** | [redacted] | [redacted] | [redacted] | [redacted] |

# Hydro Thermal Operations Capital Plan over Plan

| **CAPITAL ($M)** | **2012 Actual** | **2013** | **2014** | **2015** |
|---|---|---|---|---|
| **Approved 2012 Capital Business Plan** | [redacted] | [redacted] | [redacted] | [redacted] |
| Business Transformation - Phase 1 Transfers to Corporate Groups | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Revised 2012 Capital Business Plan** | [redacted] | [redacted] | [redacted] | [redacted] |
| **Operations Projects Changes** | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Schedule Change (deferred, cancelled or advanced) | [redacted] | [redacted] | [redacted] | [redacted] |
| Scope Changes | [redacted] | [redacted] | [redacted] | [redacted] |
| Cost Changes (escalation and revised estimates) | [redacted] | [redacted] | [redacted] | [redacted] |
| New Project (from Plant Condition Assessment) | [redacted] | [redacted] | [redacted] | [redacted] |
| Other | [redacted] | [redacted] | [redacted] | [redacted] |
| **Destiny Project Changes** | [redacted] | [redacted] | [redacted] | [redacted] |
| Niagara Tunnel Project | 8 | 5 | -32 | 0 |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Total 2013 Capital Submission** | [redacted] | [redacted] | [redacted] | [redacted] |
| **2013 Capital Submission versus Revised 2012 Capital BP** | [redacted] | [redacted] | [redacted] | [redacted] |

# Hydro Development / Thermal Repowering Projects

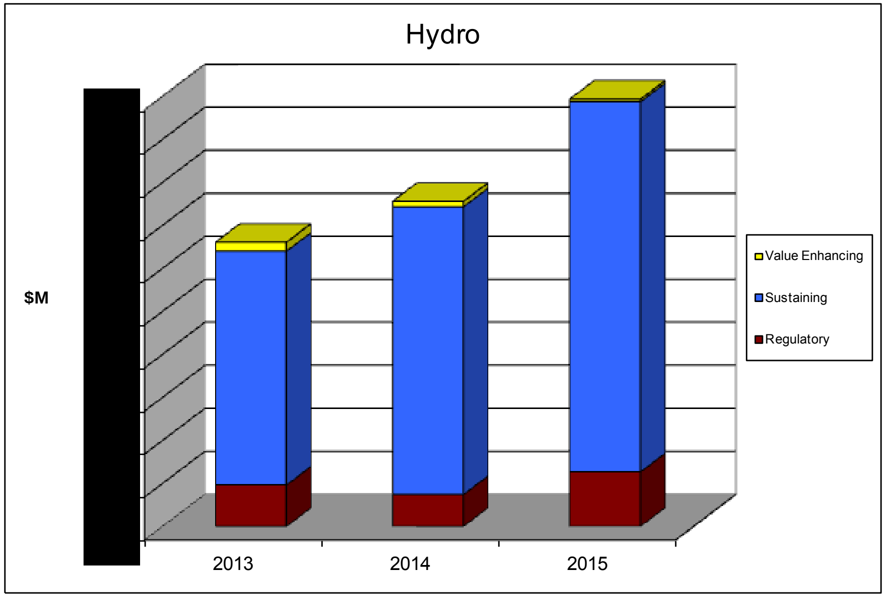
| Base Case | Capacity | LUEC | 2012 LTD | 2013 | 2014 | 2015 | 2016 | 2017 | Future costs | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | MW | cents/kWh | $M | $M | $M | $M | $M | $M | $M | $M |
| **Projects In Execution (HTO)** | | | | | | | | | | |
| Niagara Tunnel Project | n/a | 6.8 | 1,316 | 184 | | | | | | 1,500 |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Total HTO** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

| Base Case | Capacity | LUEC | 2012 LTD | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | MW | cents/kWh | $M | $M | $M | $M | $M | $M | $M | $M |
| **Projects In Definition Phase (CBD)** | | | | | | | | | | |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Ranney Falls | 9 | 10 to 12 | 1 | 3 | 19 | 19 | 1 | | | 42 |
| SAB PGS Reservoir Rehabilitation | n/a | n/a | 7 | 3 | 0 | 0 | 176 | 176 | | 362 |
| **Total CBD (Definition Phase)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

* Projects in Definition Phase are included and funded in the Corporate Business Development (CBD) Business Plan

- Projects in execution phase included in the HTO Business Plan. Projects in Definition Phase (except Thunder Bay GS) included and funded in the Corporate Business Development (CBD) Business Plan
- Projects in Definition Phase, including [redacted], Ranney Falls and SAB PGS Reservoir Rehabilitation, will be transferred to HTO after execution phase releases are approved
- [redacted]
- High Planning Scenario projects including [redacted] and Lake Gibson are included in the Corporate Business Development Business Plan

# Project Expenditures on Existing Assets



[redacted]

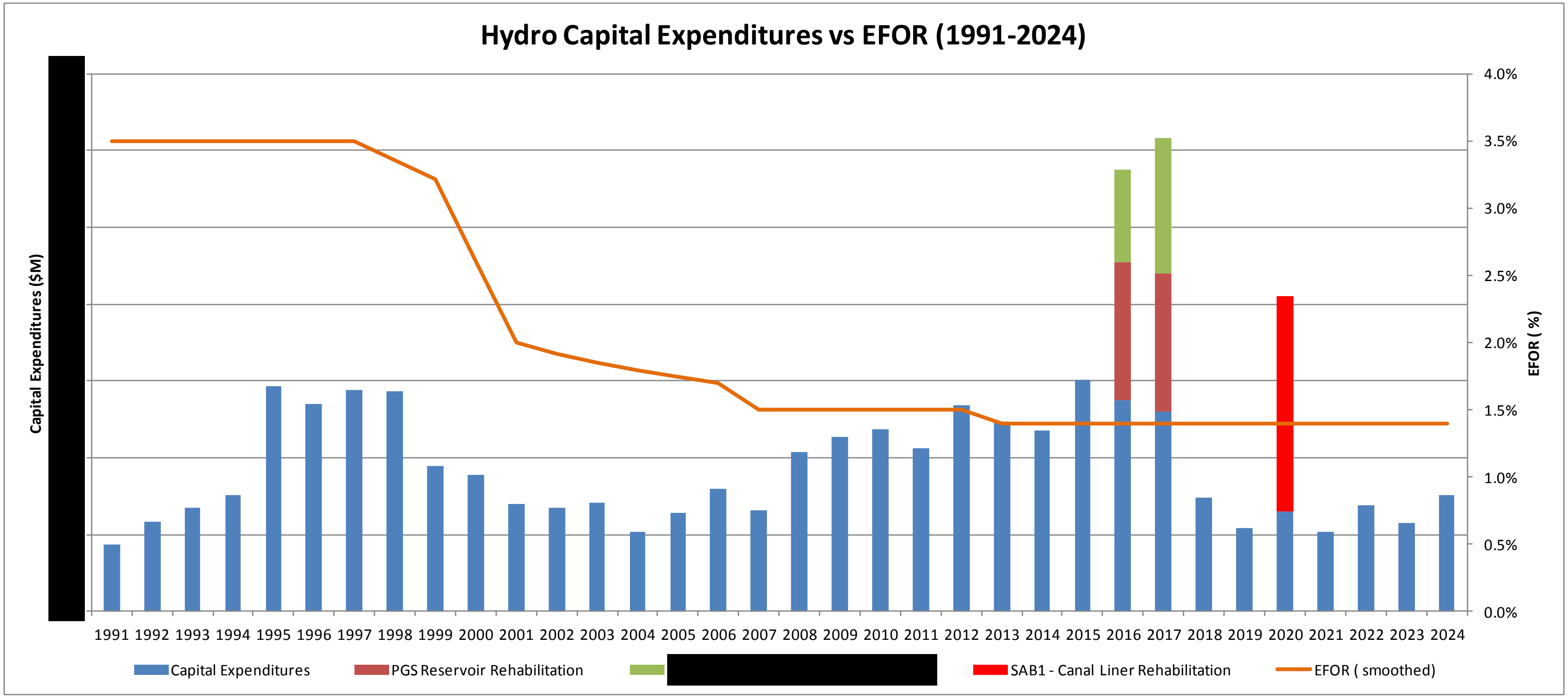
- ➢ Continued re-investment for the long term safety and sustainment of the existing assets includes project expenditures averaging [redacted] per year (Capital ([redacted]) & OM&A ([redacted]) )
- ➢ Determination of investment levels and priorities are based on Plant Condition/Engineering Risk Assessments and inspections/testing, and consider station/fleet age , type of equipment, station role (peaking vs base), reliability targets, contract commitments [redacted]), and business objectives and risks
- ➢ Hydro re-investment levels of ~1% of the "replacement cost" (excluding new facilities) are based on good practice
- ➢ Major Hydro investments during planning period include:
  - replacement of ageing "power train components" such as turbines, generators, transformers
  - repairs, rehabilitation or replacement of ageing civil structures including powerhouses, penstocks, dams, sluiceways and bridges
  - replacement or refurbishment of sluicegates & stoplogs (regulatory/safety) and headgates
  - replacement of control equipment (automation) to improve efficiency and accommodate market dispatch requirements
- ➢ [redacted]

# Hydro Thermal Operations Existing Fleet Project Portfolio Plan over Plan

| | 2012 | 2013 | 2014 |
|---|---|---|---|
| **2012-2014 BP** | | | |
| Hydro Capital and OM&A Project Investments (M$) | [redacted] | [redacted] | [redacted] |
| Thermal Capital and OM&A Project Investments (M$) | [redacted] | [redacted] | [redacted] |
| 2012-2014 BP Total Hydro + Thermal Investment | [redacted] | [redacted] | [redacted] |
| **2013-2015 BP** | | | |
| Hydro Capital and OM&A Project Investments (M$) | [redacted] | [redacted] | [redacted] |
| Thermal Capital and OM&A Project Investments (M$) | [redacted] | [redacted] | [redacted] |
| 2013-2015 BP Total Hydro + Thermal Investment | [redacted] | [redacted] | [redacted] |
| | | | |
| Total HTO Project Portfolio Plan Over Plan Change | [redacted] | [redacted] | [redacted] |

- In the 2012-2014 period, the HTO operations project portfolio (Capital and OM&A Non Standard projects) [redacted] by a total of [redacted] and [redacted] of Hydro value-enhancing projects

# Historical Hydro Capital vs EFOR



- From 1990 to 2003, large Hydro stations primarily built before 1958 were rehabilitated (eg, Saunders, SAB 2, Otto Holden, and Chenaux)
- From 2006 to 2020, remaining large stations have been, or will be rehabilitated (eg, Abitibi Canyon, Des Joachims, Decew Falls, Stewartville, Mountain Chute)
- In addition, large civil projects (PGS Reservoir liner rehabilitation, [redacted] and SAB 1 canal rehabilitation) are planned
- The investment program, along with the Leading Edge Maintenance Program, has resulted in significant reliability (EFOR) improvements.

Note: Capital Costs in $ of the year

# Hydro Thermal Operations Staff Plan & Strategy

[redacted]

- HTO expected to achieve overall BTS end state staff numbers in 2015
- Overall HTO attrition rates favourable, however, mismatches in retirement vs ongoing skill requirements will necessitate replacements in critical areas (eg operators)
- [redacted]

OPG CONFIDENTIAL

ONTARIO POWER GENERATION

[redacted]

# Key Business Risks

| | | Risk Ranking |
|---|---|---|
| 1 | [redacted] | [redacted] |
| 2 | [redacted] | [redacted] |
| 3 | Aboriginal: Increasing complexity of role and potential cost increases for unsettled past grievances | Medium |
| 4 | Uncertainty of full cost recovery for Hydro Regulated Assets and Niagara Tunnel Project | Medium |
| 5 | Implementation costs of new Provincial Dam Safety technical guidelines. Overall cost risk has been reduced compared to previously proposed MNR guidelines last year. Site specific impacts need to be assessed and could result in additional capital costs not included in plan ($100M to $400M) | Medium |
| 6 | Environmental risks associated with Ontario Endangered Species Act and Federal Species at Risk Act (compliance may require physical improvement costs and/or impacts on production/revenue) ($100M ) | Medium |
| 7 | Increased cost and delayed completion of destiny projects (NTP – Low; [redacted]) | Low |
| 8 | Increased costs due to new Heritage Act ($30M) | Low |
| 9 | New requirements for Permits to Take Water | Low |
| 10 | Uncertainty with future reliability of Hydro and Thermal plants associated with changing operating modes (eg, more stops and starts and gate operations due to SBG mitigation and wind integration) | Low |
| 11 | Structural and other operational risks associated with AAR induced concrete growth at Otto Holden and Saunders, ageing penstocks, and ageing bridges in Niagara | Low |
| 12 | Underestimating Future Cost Escalation for Major Equipment and Civil Construction | Low |
| 13 | Uncertainty with successful implementation of IMT Project and adequacy of Passport/Asset Suite | Low |

ONTARIOPOWER GENERATION

# Looking To The Future - Opportunities

The following opportunities and strategies will be reviewed by HTO during the 2013-2015 BP Period

1. Transition the business to a more cost variable model
    - Optimization of Hydro overhaul and major maintenance resourcing strategy
    - [redacted]
    -
2. [redacted]
3.
4.
5. Investment Strategy aligned with regulated, [redacted] [redacted] requirements

# Appendices

# Hydro Asset Profile

## STATIONS PROFILE

| | |
|---|---|
| NO. OF STATIONS | 65 |
| AVERAGE ENERGY | 34.3 TWh/yr |
| CAPACITY | 6996 MW |
| AVERAGE AGE | 71 yrs |
| NO. OF GENERATING UNITS | 234 |
| SMALLEST / LARGEST UNIT | 1 MW / 137 MW |
| NO. OF DAMS | 232 |
| BOOK VALUE OF ASSETS | ~$7.1 B |

## PEOPLE / WORK CENTRES / LAND

| | |
|---|---|
| PLANT GROUPS | 5 |
| WORK CENTRES | 22 |
| CONTROL CENTRES (includes International Control Dam Control Centre) | 7 |
| TOTAL STAFF (PG only) | ~980 (2012 Plan) |
| OPERATORS | ~105 |
| NO. OF RIVER SYSTEMS | 24 |
| HYDRO OWNED LAND | ~17,000 hectares |
| LEASED LAND (flooded) | ~800, 000 hectares |

# Thermal Asset Profile

[redacted]

# HTO Reliability Performance

| | 2012 Budget | 2012 YE Actuals | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|
| **Hydro** | | | | | |
| Availability | 91.2% | 91.2% | 91.6% | 92.6% | 91.2% |
| Scheduled Outage Factor | 7.4% | 7.4% | 7.3% | 6.3% | 7.7% |
| EFOR | 1.4% | 2.0% | 1.4% | 1.4% | 1.4% |
| Spill Losses (Forced + Planned Outages) (GWh) | 220 | 198 | 366 | 384 | 368 |
| **Thermal** | | | | | |
| Start Guarantee | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| CAWN | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Maintenance Outage Factor (%) | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| EFOR(OP) | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

# Runner Replacement /Upgrade Program

| 2013-2015 BP Runner Upgrades | Completed 1992 to 2011 | 2012 Actual | 2013 | 2014 | 2015 | 2013-2015 BP Total | 2016 | 2017 | 2018 | 2019 | 2020 | Total (2013 to 2020) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **CAPACITY (MW)** | 464 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **ENERGY (GWh)** | 885 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **TOTAL CAPITAL COST (M$)** | 243 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **OM&A COST (M$)** | 23 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

- All runner replacements that were in the plan, solely to enhance value (not sustaining), have been deferred to the 2016 to 2020 period (eg Otter Rapids)
- During the Business Plan period, HTO capacity and energy are expected to [redacted] respectively, as a result of runner upgrades. This is a [redacted] compared to last year's plan
- From 1992 to 2012, HTO will have realized an increase in capacity of 464 MW and 885 GWh, as a result of the runner upgrade program

| ONTARIO POWER GENERATION | Project Number: CHAF0035 | Facility: Chats Falls GS | Page: 1 of 12 Rev. 00 |
|---|---|---|---|
| | **BUSINESS CASE SUMMARY**<br>**Main Dam Concrete Rehabilitation** | | |

## 1. RECOMMENDATION

Approve this full release of $40M to perform the rehabilitation of the concrete main dam, stop log sluices, at Chats Falls Generating Station, with 50% of the costs recoverable from Hydro Québec. This rehabilitation project will address existing concrete deterioration, operational problems with the stop log sluices, and emerging dam and personnel safety concerns. The project will be completed over a 5 year period to accommodate Ministry of Natural Resources (MNR) restrictions, and the historical flow and spill conditions (ie, minimize production losses).

**Total Investment Cost:** *$40M Gross (includes $180k Developmental Release funding - $162k spent to date as of end of 2011. 50% of these costs are to be recovered from Hydro Québec)*

| | 2011 LTD | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|
| Project Cashflows Gross cash flows ($M) | 0.2 | 7.4 | 8.3 | 8.4 | 8.2 | 7.5 | 40 |
| Project Cashflows Net cash flows ($M) | 0.1 | 3.7 | 4.2 | 4.2 | 4.1 | 3.8 | 20 |
| 2012 Final Budget Version OPG share ($M) | 0.1 | 2.5 | 2.5 | 2.0 | 2.0 | 2.0 | 11 |

| | |
|---|---|
| **Expenditure Type:** | Non-Standard |
| **Investment Type:** | Sustaining – Maintain Condition Non-Production |
| **Release Type:** | Full release under OAR element 1.1 |

**Funding:** The 2012 Business Plan includes funds for project execution in years 2012 - 2016. Additional scope items were identified during the definition phase activities and the RFP fixed price proposals were not received until after the finalization of the 2012-2016 Business Plan. The increased 2012 cash flows will be managed within the 2012 OSPG Non-Standard envelope, and future years (2013-2016) will be re-programmed in the 2013-2015 Business Plan. The 2001/2008 Chats Falls PCAs and 2001 Life Cycle Plan include this work.

**Investment Financial Measures:** The Present Value (PV) of the total costs related to this project is ($25.2M).

## 2. SIGNATURES

**Submitted by:**

Feb 14/12
Jim Moreland Date
*OSPG Plant Group Manager*

**Recommended by:**

Feb 17, 2012
Frank Chiarotto Date
*Senior Vice-President, Hydro-Thermal*

**Finance Approval:**

Feb 22/12
Donn Hanbidge Date
*SVP & Chief Financial Officer*

**Line Approval Per OAR:**

4 May 12
Tom Mitchell Date
*President & Chief Executive Officer*

## 3. BACKGROUND & ISSUES

*Station Description:*

Chats Falls GS is located on the Ottawa River, 56 km northwest of Ottawa. The station was built in 1931 and has 8 units with an installed capacity of 192 MW. The plant is owned jointly by Ontario Power Generation and Hydro Québec. Energy production from the facility is shared equally by both entities and investments are reimbursed by Hydro Québec on a project-by-project basis as per the OPG/Hydro Québec Operating Services Agreement. In 2011, OPG's revenue was $24M based on half of the total energy production of 562 GWh. Chats Falls is considered a "Middle-of-the-Pack" asset in OPG Hydroelectric portfolio. Planned investment over the next ten years represent approximately $37M (OPG costs), with the major projects including: main dam concrete restoration, replacement of the A/C station service, restoration of the generator rotor field poles, excitation system replacement and multiple repairs on the powerhouse building, etc. The NPV for the OPG owned half of the station, including the costs of the preferred alternative, is $263M. This project secures the ongoing profitability of the station to OPG and Hydro-Québec.

*Background and Issues (Refer to Appendix A for site layout):*

The dam is divided into thirteen sections (also called divisions) for construction and identification purposes (see site layout in Appendix A). It was constructed in 1930-1931 using natural sand and coarse crushed rock aggregate and is 5.24km long and spans across the Ontario-Québec border by approximately 2.5km onto the Quebec side. The main dam includes four sluiceways and more than 4.5km of concrete gravity sections. The four sluiceway structures (Victoria Island, Ragged Chute, Wolverine Chute and Merrill Island) total 74 stop log sluices, with 42 in Québec and 32 in Ontario, and a sluiceway that has four automated gates.

The structures are currently experiencing significant deterioration leading to operational problems and potential structural, stability, and personnel safety issues. Structural and weathering-related deterioration of the dams and sluiceways has been observed and monitored since the 1940's. External engineering services were retained by Ontario Power Generation to review available information, carry out assessment inspections and prepare a complete scope and technical specification. A previous assessment also identified the presence of Alkali-Aggregate Reactivity (AAR) which has contributed to the concrete deterioration. A definition phase was completed with the objective to ensure that maximum life span would be attained while minimizing the investment costs for both OPG & Hydro Québec and extend the service life of the dam for an additional 40 years.

The powerhouse as well as the sluice gate adjacent to it is not included in the work, with the exception of the replacement of the handrails and minor concrete work on the Powerhouse headworks (Division 6). Three of four main sluice gates were recently replaced with the final gate to be completed in 2012.

This project will restore the dam structures and associated equipment to address existing deterioration, operational problems, and emerging dam and personnel safety concerns. The project will be completed over a 5 year period to accommodate Ministry of Natural Resources (MNR) restrictions, and the historical flow and spill conditions (ie, minimize production losses).

**Summary of the current major problems**

The main issues are as follows:

- There is extensive leakage and deterioration in various sections of the main gravity dam which is rated as poor (per dam safety criteria). Sealing of the joints/cracks and repairs to these sections is needed to ensure continued stability of the dam.
- The leakage should be repaired in the near future to prevent more extensive deterioration and increased rehabilitation costs in the future.
- The sluiceway decks and dam crest have significant damage including spalled and cracked concrete leading structural problems and inadequate hand rail anchoring. Two cracked sluiceway decks and end piers are "tilted" inwards limiting the removal and installation of stop log.
- The handrails are deteriorated and non-compliant with current building codes.

Further details are provided below.

**Structural and Operational Issues**

*1. Gravity sections*

The gravity sections at Chats Falls GS have extensive deterioration which has been exacerbated by concrete growth (Alkali-Aggregate Reactivity). Some sections will require extensive repairs to maintain the structural integrity and prevent potential problems such as dam failure and uncontrolled leakage.

Divisions #5 and #9 have major stress cracks and are leaking. The Division #5 leaks along the vertical joint and extends along a horizontal joint and water is leaking onto the adjacent roadway, creating significant ice buildup and hazardous conditions on the road during winter. Division #9 has diagonal cracks and horizontal joints that are leaking. Temporary sealing repairs were performed at some sections in 2000, however, these sections are leaking again.

*2. Stop log sluiceway structures*

There are four stop log sluiceways at Chats Falls GS: Merrill Island, Wolverine Chute, Ragged Chute and Victoria Island. The stop log sluiceways at Chats Falls were designed with steel gains and utilized wooden stop logs, which are removed and installed in the sluiceway using a mechanical log lifter located on the upper deck of the structure. The stop log sluiceways are also afflicted with AAR, and major problems have developed the past several years.

As such, the 2008 Plant Condition Assessment (PCA) recommended concrete restoration of the decks, expansion joints and end piers at Merrill and Wolverine sluiceways. The Victoria Island sluiceways are in better condition and require less repair. Surveys and reviews have also been undertaken over a number of years in response to concerns over inward movement of stop log sluiceways end piers due to AAR. This inward movement has led to a reduction of the distance between the gains of the sluiceways and inability to remove or install stop logs in the end sluices. The movement of the gains due to concrete growth jammed the wooden logs making these sluices inoperable.

2.1 Merrill Island & Wolverine Chute Sluiceways

The Merrill Island & Wolverine chute sluiceways respectively consist of 22 and 10 stop log sluiceways. Both structures are entirely located in the Province of Quebec. For both structures, there are signs of movement and horizontal cracking on both end piers, and portions of the deck are collapsing due to the pier movement. Rotation of the end piers resulted in closing of the log gains and the stop logs are jammed in position and cannot be removed. The proper gain opening dimensions need to be re-established so that new logs can be installed.

2.2 Victoria Island Sluiceway

The Victoria Island sluiceway consists of 10 stop log sluiceways. There are signs of some minor movement on both end piers. New stop logs were installed in October 2009.

**Concrete deterioration**

*1. Gravity sections*

All gravity sections are showing signs of concrete erosion at the waterline as a result of the water and ice action. There is also significant concrete deterioration along the vertical joints on the upstream face of the dam, and significant surface scaling on the crest along both edges where the handrails are anchored. This deterioration results in structural issues with the handrail anchorage as well as an uneven walking surface. The downstream face has severely deteriorated concrete surfaces due to leakage through joints, spalling of concrete due to freeze-thaw action and vegetation growth.

*2. Stop log sluices structures*

All stop log sluice structures show signs of concrete erosion at the waterline elevation on the exterior piers, as a result of the water and ice action. There is major surface scaling and spalling on the crest of the sluiceway sections, along both edges where the handrails are anchored. This deterioration results in structural issues with the handrail anchorage.

A technical specification was prepared and includes several types of repair methods that have been specifically developed for the different types of problems. This approach will ensure that for each type of deficiency, the most appropriate repairs will be performed to achieve optimum results and achieve maximum extension of the service life.

**Handrail issues**

*1. Handrails*

The gravity sections & stop log sluices structures are equipped with different types of handrails that do not meet OHSA regulations. Replacement of the handrails and installation new anchors was recommended. The existing cast iron upstream railing is poorly anchored in many locations, making the railing loose and generally unsafe for site staff. The railing on the Merrill Sluices has been temporarily stabilized. The paint on the railing has been tested positive for lead contamination. The assessment from 2010 clearly stated the need to remediate the situation by replacing all 5km of handrails with a new design.

## 4. ALTERNATIVES & ECONOMIC ANALYSIS

The Present Value of the total project costs are shown in the table below. Although the present value of the recommended alternative (Alt.3) is $7.4M worse than deferring the project for an additional 12 years (Alt.2), the dam safety and operational risks associated with a deferral are considered to be unacceptable.

| | Base Case | Alt 1 | Alt 2 | Alt 3 (Recommended) |
|---|---|---|---|---|
| Remaining costs (k$) | 0 | $49,869 | $58,984 | $39,846 |
| PV (2012) (k$) | 0 | ($26,452) | ($17,768) | ($25,216) |

***Base Case:*** ***Status Quo (Do not conduct any concrete repairs or handrail replacement).***

- **Not Recommended**

This option is not recommended because it will not address the deficiencies outlined in the Background & Issues section. The option of leaving the stop log sluiceway end piers and expansion joints in the existing state with no concrete restoration is not recommended because it does not address the current concerns with structural integrity and operational problems which will lead to dam safety problems and possibly plant decommissioning or rebuild.

***Alternative 1:*** ***Restore the gravity sections only – Defer stop log sluices repairs five years.***

- **Not Recommended**

This alternative consists of complete restoration of all gravity sections, as well as replacement of both upstream and downstream handrails. Concrete restoration for the gravity sections includes sealing and reinforcement of cracks and construction joints, sealing of underwater cracks, restoration of deck edges and upstream dam face, restoration of eroded concrete at the waterline, and removal of deteriorated concrete and vegetation on downstream face. The scope of work also includes the restoration of the bulkhead Division #9 which is currently experiencing severe leakage, concrete deterioration and structural integrity issues.

- This alternative will reduce leakage through the dam as much as practical, and mitigate further concrete deterioration.
- This alternative will allow OPG to extend the service life of the water retention structures and avoid major concrete restoration work for a minimum of 40 years.
- This option will address the current problems with old and non-compliant handrails.

This option does not address current issues and concerns associated the four stop log sluiceways. Stop log sluices structures will continue to deteriorate and could eventually result in significant operational problems of removal and installation of the stop logs. There is a risk of failure of the stop logs leading to an uncontrolled released of water. There are additional risks with loss of structural integrity caused by severe deformations of the stop logs which could result in partial collapse, having a significant negative impact on the Health & Safety of the workforce, and unfavorable consequences to the reputation of both OPG and Hydro Québec. Loss of structural integrity could also result in major Dam Safety incident with the uncontrolled release of water. This could result in eventual plant/dam decommissioning or rebuild.

➔ Cost = approx. $49,869k
➔ PV of Costs = ($26,452k)

***Alternative 2:*** ***Restore the stop log sluices only – Defer gravity sections repairs 12 years.***

- **Not Recommended**

This alternative consists of performing complete restoration of all four stop log sluiceway structures, as well as replacement of both upstream and downstream handrails. Concrete work associated with this alternative consists of removal and reconstruction of concrete decks of the first and last sluice ways of both Merrill Island (Division 12) and Wolverine Chute (Division 10). The piers will also be repaired.

This alternative also includes resurfacing of concrete decks at all stop log sluiceways, and re-sealing of all expansion joints. The existing wooden stop logs will be replaced with pre-fabricated steel stop logs and rails for the log lifters will be reinstalled and re-aligned.

- This alternative will ensure that operational risks associated with deformed concrete structures are mitigated;
- This alternative will allow extension of the service life of the sluiceways for 40 years.

While this alternative will aid OPG in protecting its assets and reduces some risks, this option will not address current issues and concerns associated with deteriorated gravity sections. The gravity sections will continue to deteriorate, additional structural issues will develop, and future project costs will escalate due to continued deterioration. Proceeding with this alternative could also have severe implications for the long term stability of the dam due to increased leakage, and erosion, which could lead to eventual plant/dam decommissioning or rebuild.

➔ Cost = approx. $58,984k
➔ PV of Costs = ($17,768k)

***Alternative 3:*** ***Restore the gravity sections and all four stop log sluices structures without any deferrals.***

- **Recommended**

This alternative consists of the complete rehabilitation of all gravity sections including all four stop log sluiceways, as well as replacement of upstream and downstream handrails. This alternative includes the work scope of both alternative #1 (restore the gravity sections) and alternative #2 (restore the stop log sluiceway structures).

- This alternative will mitigate the operational risks associated with deformed concrete structures and sluiceways.
- This alternative will allow a 40 year extension of the service life of the main gravity dam and sluiceways.
- This option will reduce leakage and mitigate further concrete deterioration.
- This option will address the current deficiencies with old and non-compliant handrails.

This option will provide the best financial solution while minimizing risks to the structures, personnel and the public. It will also allow the project to be completed within the planned five years of work.

➔ Cost = approx. $39,846k
➔ PV of Costs = ($25,216k)

**Other alternatives considered but rejected**

***Alternative 4:*** ***Defer execution of the entire project till 2017.***

- **Not Recommended**

This alternative postpones the execution of the work by five years. This option is technically unacceptable due to the significant dam safety risks of failure of the dam or sluiceway structures and loss of flow control capability of some sluiceways. This would also negatively impact OPG & Hydro Québec's public reputations. This option would not properly mitigate current deficiencies with non-compliant handrails. Finally this option would cause accelerated deterioration to the concrete structures resulting in significant increases in future repair costs estimated at 20% the five year period.

***Alternative 5:*** ***Restoration of the gravity sections, all four stop log sluices structures plus applying sealant to the concrete structures.***

- **Not Recommended**

This alternative includes the same scope of work as Alternative #3 but with the addition of a special concrete penetrating sealant on the structures (approximate cost of $1 M). The dam was constructed in the 1930's without added air entrainment, a technology that was not available at the time of construction. Application of concrete sealant may better protect the surfaces from moisture ingress and slow down the amount of water infiltrating the concrete preventing further surface deterioration. Application of such a sealant may extend the service life for an estimated five years by minimizing water infiltration in the concrete and reducing the impact of freeze-thaw cycles as well as reducing future vegetation growth. However, this is an assumption which cannot be confirmed by the project's engineering support, nor will the contractor guarantee the service life extension. Although this option was found to be technically acceptable, there is no financial benefit to proceed with this as the Net Present Value is worse than Alternative #3.

## 5. THE PROPOSAL

Restoration of the stop log sluices, head works and main dam gravity sections at Chats Falls Generating Station as per Alternative #3 will include:

- Complete rehabilitation of all gravity sections (including sealing and reinforcement of cracks and construction joints, sealing of underwater cracks, restoration of deck edges and upstream face, restoration of concrete at waterline erosion, removal of deteriorated concrete and vegetation on downstream face).
- Complete restoration of all four stop log sluiceway structures (including removal and reconstruction of concrete decks of the first and last sluice ways and reconstruction of the piers and replacement of all exterior sluices.
- Resurfacing of concrete decks on all stop log sluices structures.
- Re-sealing of all expansion joints.
- Reinstallation & re-alignment of the log lifter rails.
- Recoating of the steel beams currently installed in the log chute (Division 8) to help minimize corrosion and extend their service life.
- Replacement of both upstream and downstream deteriorated and non-compliant handrails.

This project will restore the dam structures and associated equipment to address existing deterioration, operational problems, and emerging dam and personnel safety concerns and extend the service life of the dam and sluiceways for about 40 years. It also addresses the safety hazards associated with old and non-compliant handrails. The project will also minimize any negative impacts to OPG's public reputation associated with the failure of the dam or sluiceway.

The project will be completed over 5 years. Due to MNR restrictions, the in-water work cannot commence before July 15th and cannot be extended beyond Oct. 15th each year. OPG provided the contractors the historical flow and spill conditions during the RFP process, and based on these conditions and the restrictions regarding in-water work the execution needs to take place over a five year period. Hydro Québec were consulted regarding the cost/schedule and agree with the project execution plan.

## 6. PROJECT SCHEDULE

| | |
|---|---|
| Q1 2012: | Project Release |
| Q2 2012: | Issue Purchase Order |
| June 2012: | Construction work at site commencement |

June to Nov. 2012:

- Sealing of underwater cracks (includes reinforcement where required) on Division 13.
- Concrete repairs (in water work) on Divisions 13 & 14.
- Concrete repairs (not in water work) on Divisions 13 & 14.
- Handrail replacement, utilities & cables trays work on Divisions 13 & 14.

May to Nov. 2013:

- Sealing of underwater cracks (includes reinforcement where required) on Division 9.
- Repairs on Division 12 (coffer dam, anchors, gains, deck repairs including overlay, rail replacement, etc.).
- Concrete repairs (in water work) on Division 9.
- Installation of stress crack anchors and epoxy injection on Division 9.
- Concrete repairs (not in water work) on Division 9.
- Handrail replacement, utilities & cables trays work on Divisions 9 & 10 (stage with other repairs as required).

May to Nov. 2014:

- Sealing of underwater cracks (includes reinforcement where required) on Division 11.
- Repairs on Division 10 (coffer dam, anchors, gains, deck repairs including overlay, rail replacement, etc.).
- Concrete repairs (in water work) on Divisions 10 & 11.
- Concrete repairs (not in water work) on Divisions 6, 7, 8, 10 & 11.
- Hand rail replacement, utilities & cables trays work on Div 6,7,8,10,11.

May to Nov. 2015:

- Sealing of underwater cracks on Divisions 3 & 5.
- Concrete repairs (in water work) on Divisions 3 & 5.
- Concrete repairs (not in water work) on Divisions 3 & 5.
- Handrail replacement, utilities & cables trays work on Divisions 3, 4 & 5 (stage with other repairs as required).

May to Nov. 2016:

- Sealing of underwater cracks on Division 1.
- Concrete repairs (in water work) on Divisions 1 & 2.
- Repairs on Division 2 (coffer dam, anchors, gains, deck repairs including overlay, rail replacement, etc.).
- Concrete repairs (not in water work) on Divisions 1 & 2.
- Handrail replacement, utilities & cables trays work on Divisions 1 & 2 (stage with other repairs as required).

| | |
|---|---|
| December 2016: | Project execution complete. |
| June 2017: | Project Closure Report (PCR). |

## 7. QUALITATIVE FACTORS

- Mitigate the risks of an uncontrolled release of water at the sluiceways with jammed stop logs.
- Improved reliability of the stop log sluices structures and gravity (bulkhead) sections, continued availability of the assets will be maintained and protected;
- Service life extension of the structures;
- Minimization of the damage caused by freeze-thaw action, waterline erosion, leakage, etc;
- Work assignment has been designated in accordance with PWU/BTU Chestnut Park Accord process;
- This work will mitigate the emerging Dam Safety concerns with the gravity sections and stop log sluiceway structures;
- This work will eliminate any safety concerns with the handrails.

## 8. POST IMPLEMENTATION REVIEW (PIR)

**For each year of programmed work:**

- After completion of the annual work, an engineering assessment to verify conformance to the engineering specifications will be performed by the engineering consultant and results will be documented in a yearly conformance report.
- Discrepancies and deviations from the technical requirements will be addressed through a review meeting and directions for subsequent work will be obtained.
- OSPG Environmental Support Unit (ESU) will perform a yearly evaluation of the work to confirm absence of negative impact on the environment.

**At the end of the project (scheduled for October 2016):**

- OSPG Asset Management (in coordination with Chats Falls Production) will confirm overall conformance to the initial technical specifications and that the following elements were properly addressed, which shall include:
  - Reduction of leakage in the gravity sections;
  - Removal of all vegetations on the gravity sections;
  - Repairing the upstream & downstream surfaces of the gravity sections;
  - Restoration of the walking surfaces on the decks and elimination of spalled concrete;
  - Elimination of the operational problems associated with stop log sluiceways;
  - Replacement of all handrails with OHSA compliant designed handrails;
- Asset Management in coordination with Dam Safety will evaluate the conformance and integrity of the rehabilitated structures and confirm performance against Dam Safety standards.
- OSPG Environmental Support Unit (ESU) will confirm that the work executed did not negatively impact the environment.

## 9. RISK ANALYSIS

| Risk Description | Impacts | Initial Risk (before mitigation) (H,M,L) | Mitigating Activities | Residual Risk(after mitigation) (H,M,L) |
|---|---|---|---|---|
| Cost | | | | |
| • Material and supplies costs escalation. | • Exceeding the release amount. | M | • Award of the contract will be done under fixed price agreement;<br>• Detailed assessment showed the extent of the work involved in providing the deliverables; | L |
| • Labor cost escalation. | • Exceeding the release amount. | M | • Award of the contract will be done under fix price agreement;<br>• Escalation included in fixed price;<br>• BTU labor agreements are mostly known for the duration of the project. | L |
| Scope | | | | |
| • Not performing or deferring the full release. | • Major risks related to structural integrity and possible equipment failure;<br>• Increased mitigation costs. | H | • Accountability for plant production staff to perform annual localized guardrail inspection & repair. | L |
| • Possibility of discovery work. | • Escalated execution costs<br>• Negative impact on the schedule and delay of the completion dates. | M | • Detailed assessment showed the extent of the work involved in providing the deliverables;<br>• [redacted] contingency included to address unknown additional scope items. | L |
| Schedule | | | | |
| • Delays in obtaining the deliverables | • Would delay the execution phase. | L | • Fixed schedule contract with hourly rates.<br>• Delivery dates will be implemented and enforced in award of contract. | L |

| Risk Description | Impacts | Initial Risk (before mitigation) (H,M,L) | Mitigating Activities | Residual Risk(after mitigation) (H,M,L) |
|---|---|---|---|---|
| • Project is not completed within the agreed 5 year window. | • Would delay the execution phase.<br>• Would incur extra costs to the contractor/OPG. | M | • Fixed schedule contract.<br>• OPG provided station historical flows & times of sluicegate operation. Contractor developed the five year schedule as per the historical operation of the facility. | L |
| • OPG requires full access to work site, stopping contractor work. | • Negative impact on the schedule and delay of the completion dates;<br>• Escalated execution costs. | H | • Contractor to be aware of possibility that OPG may require access to site and will plan accordingly;<br>• OPG will work closely with contractor to minimize impact on work execution from unnecessary site access. | L |
| • Contractor initiates and continue in-water work outside the MNR allowed period | • Fines from the Ontario MNR. | L | • An execution schedule provided by contractor will be approved by OPG prior to being used by contractor.<br>• No in-water work to be executed prior to July 15th of each year. | L |
| **Resources** | | | | |
| • Union strike or other work stoppage | • Negative impact on the schedule and delay of the completion dates;<br>• Escalated execution costs. | L | • CPA Collective agreements recently ratified provide up to 3 years without labor concerns. | L |
| **Environmental** | | | | |
| • Construction or demolition materials enter the Ottawa River or are disposed of on firm lands. | • Possibility of fines from the Quebec MNR as well as from the Ontario MNR;<br>• Possible damage to the ecosystems and natural resources. | M | • Proposals will include complete plan to minimize or eliminate as much feasible potential spills and releases of materials into the environment;<br>• OPG prepared a complete environmental specification to accompany the work;<br>• Site manager will monitor to ensure conformance with the environmental specification. | L |
| • Sensitive species are disturbed or negatively impacted. | • Partial or total loss of local population of sensitive species, with potential regulatory and stakeholder consequences. | L | • Proponent's proposals will include complete plan to minimize any negative impacts on sensitive species.<br>• Certain wildlife habitats may be relocated for the duration of the work to minimize any impacts. | L |

ONTARIO POWER GENERATION

# HYDROELECTRIC Summary of Estimate

| | |
|---|---|
| Date | February 12, 2012 |
| Project # | CHAF0035 |

**Facility name:** Chats Falls GS

**Project Title:** Main Dam Concrete Restoration

| | 2011 LTD | 2012 | 2013 | 2014 | 2015 | 2016 | TOTAL | % |
|---|---|---|---|---|---|---|---|---|
| **Capital** | | | | | | | | |
| Project Management / Engineering (012) | | $ 225 | $ 232 | $ 239 | $ 246 | $ 253 | $ 1,195 | 3% |
| Consultant / Engineering (310) | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Construction/Installation** | | | | | | | | |
| Hydroelectric (PWU labour) (10) | | $ 65 | $ 67 | $ 58 | $ 71 | $ 134 | $ 395 | 1% |
| Contractor / (BTU labour) / EPSCA (310) | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Interest (700) | | | | | | | $ - | 0% |
| Contingency (998) | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **TOTAL (GROSS)** | **$ 162** | **$ 7,440** | **$ 8,315** | **$ 8,353** | **$ 8,200** | **$ 7,530** | **$ 40,000** | **100%** |
| Hydro-Quebec Cost Recovery (840) | $ 81 | $ 3,720 | $ 4,158 | $ 4,177 | $ 4,100 | $ 3,765 | $ 20,000 | 50% |
| **TOTAL (NET)** | **$ 81** | **$ 3,720** | **$ 4,158** | **$ 4,177** | **$ 4,100** | **$ 3,765** | **$ 20,000** | **50%** |

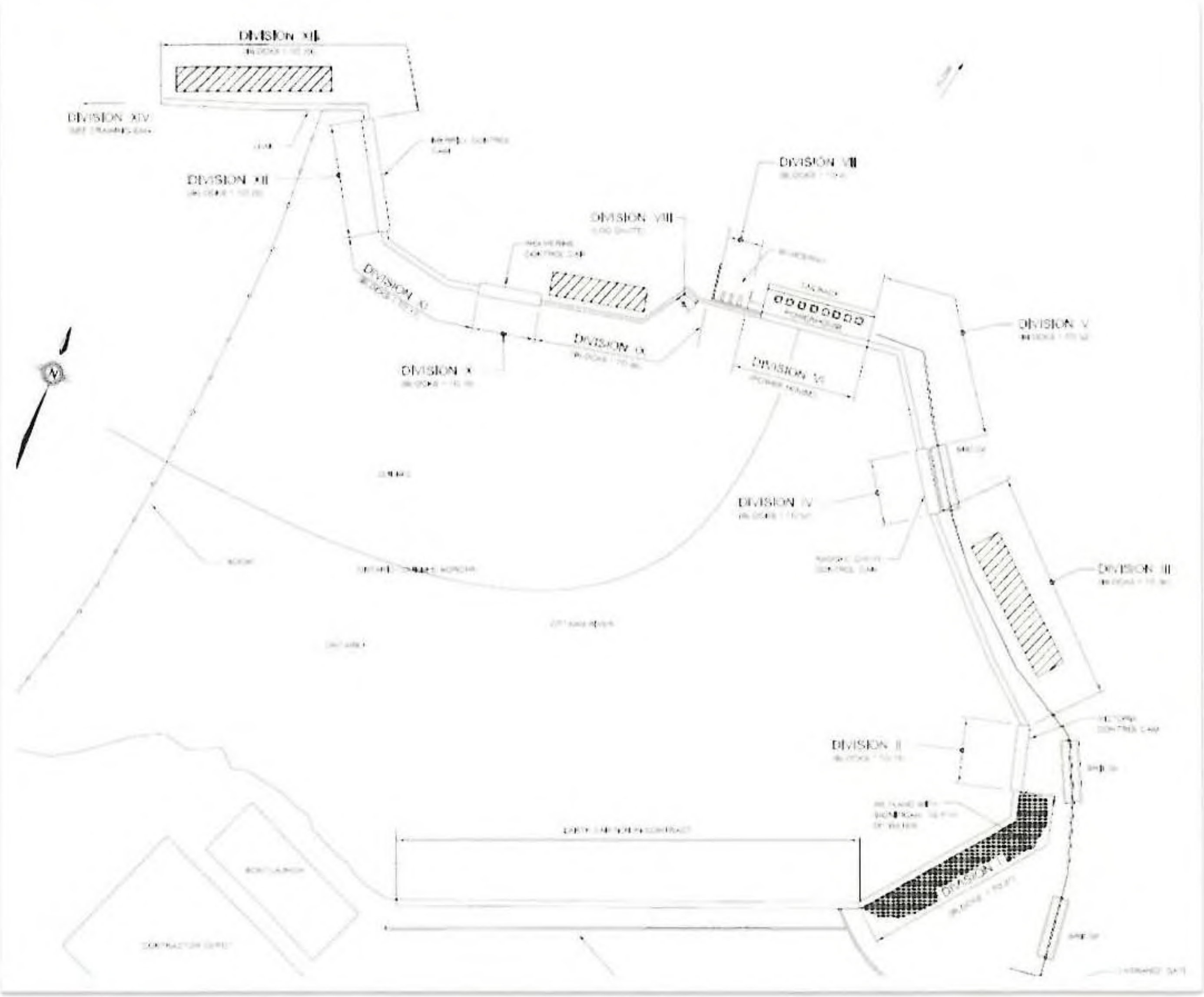
Costs in $k

Notes: 1 Schedule: Start Date: April 2012
In-service Date: November 2016

2 Escalation rates are based on current allocation rates provided by Corporate Finance

| | |
|---|---|
| **Prepared by:** Chris Hamel<br>Chris Hamel, P. Eng. | **Approved by:**<br>Gerry Foote Gerry Foote |
| *Project Engineer* | *Production Manager* |
| Date: February 12, 2012 | Date: Feb 14, 2012 |

Appendix A: Site plan – Chats Falls GS



ONTARIOPOWER GENERATION

Records File Information:
See Guidance Section

OPG-FORM-0076-R003*

# Type 3 Business Case Summary

Final Security Classification of the BCS: **Internal Use Only**

To be used for investments/projects meeting Type 3 criteria in OPG-STD-0076.

**Executive Summary and Recommendations**

| | | | |
|---|---|---|---|
| **Project #:** | SABP0053<br>SABP0056 | **Title:** | PG3 Overhaul<br>PG3 New Runner Blades |
| **Phase:** | Execution | **Release:** | Full |
| **Facility:** | SAB PGS (NF282) | **Records File:** | 08707.021 |
| **Class:** | Capital and OMA | **Investment Type:** | Sustaining |

**Project Overview**

**We recommend the release of $9,043 k ($[redacted]base costs plus $[redacted]contingency).**

Sir Adam Beck (SAB) Pump Generating Station (PGS) is a six unit reversible pump-turbine plant capable of pumping water from the outlet of the tunnels and canal of the SAB complex, into a storage reservoir, and generating from that reservoir by discharging the stored water back into the SAB Complex head pond.

The primary driver for this project is to mitigate the environmental risk of a potential oil spill from a runner seal failure or oil leakage from the coupling flange between the runner and shaft. Other key drivers are to address reliability issues with major components and the risk of poor runner blade condition. Based on the PG6 overhaul experience, complete overhaul of the unit including replacement of the runner blades is required to reduce the oil leak risk and ensure reliable unit operation for 15 years.

The required funding for this project is broken down as follows:

| k$ | 2013 | 2014 | 2015 | Total |
|---|---|---|---|---|
| **OM&A** - SABP0053 Overhaul | 1,995 | 4,347 | | 6,342 |
| **Capital** - SABP0056 New Runner Blades | 424 | 1,646 | 631 | 2,701 |
| **Total Project Cost** | **2,419** | **5,993** | **631** | **9,043** |
| **BP13-15 OM&A** - SABP0036 (Program) | 1,200 | 4,050 | 4,500 | 9,750 |
| **BP13-15 Capital** | 0 | 0 | 0 | 0 |
| **Variance - OM&A** | 795 | 297 | (4,500) | (3,408) |
| **Variance - Capital** | 424 | 1,646 | 631 | 2,701 |

The unit will be overhauled from September 2013 to July 2014.

The NPG 2013-15 Business Plan BURSA identified PGS unit reliability (forced outage due to oil leakage or generator rotor spider arm cracking) as one of five key business risks for the plant group. The mitigation plan for this risk is to perform the planned overhauls as per the approved work program to address oil leakage issues, and to continue with the established NDE and repair program of the generator rotor.

A spare set of runner blades was purchased in July 2012 as a Capital Spare under project SABP0040 to mitigate the risk of runner blades not being acceptable for use on a unit during the PGS overhaul program. Due to the long lead time to manufacture a set of runner blades (~18 months), the capital spare set will be used on PG3 during this overhaul and the new blades purchased under this project will be put back into inventory as the Capital Spare to protect the remainder of the overhaul program.

[redacted]

Execution of this work will address oil leakage issues, reliability issues with other components, and poor runner blade condition on PG3 and help to refine the scope of work and associated costs for the rest of the units.

**Project Cash Flows**

| k$ | LTD | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Future | Total |
|---|---|---|---|---|---|---|---|---|---|
| Currently Released | | | | | | | | | |
| Requested Now | | 2,419 | 5,993 | 631 | | | | | 9,043 |
| Future Required | | | | | | | | | |
| **Total Project Cost** | | 2,419 | 5,993 | 631 | | | | | 9,043 |
| Ongoing Costs | | 0 | 0 | 0 | | | | | 0 |
| **Grand Total** | | 2,419 | 5,993 | 631 | | | | | 9,043 |

| | | | |
|---|---|---|---|
| **Estimate Class:** | Class 3 | **Estimate at Completion:** | 9,043 |
| **NPV:** | $ k | **OAR Approval Amount:** | 9,043 |

**Additional Information on Project Cash Flows (optional):**

The 2013 budget includes funding of $1,200k OM&A for the PGS overhaul program. Changes will be managed within the Plant Group budget envelope.

**Approvals**

| | Signature | Comments | Date |
|---|---|---|---|
| This BCS represents the best option to meet the validated business need in a cost effective manner. | | | |
| **Recommended by:**<br>Al Reid<br>Plant Group Manager, Niagara Plant Group<br>Project Sponsor | Allan Reid | | May 10/13 |
| I concur with the business decision as documented in this BCS. | | | |
| **Finance Approval:**<br>Don Power<br>VP Investment Planning | | | May 14/2013 |
| I confirm this project will address the business need, is of sufficient priority to proceed, and provides value for money. | | | |
| **Approved by:**<br>Frank Chiarotto<br>SVP HTO, per OAR 1.2 | | | May 15, 2013 |

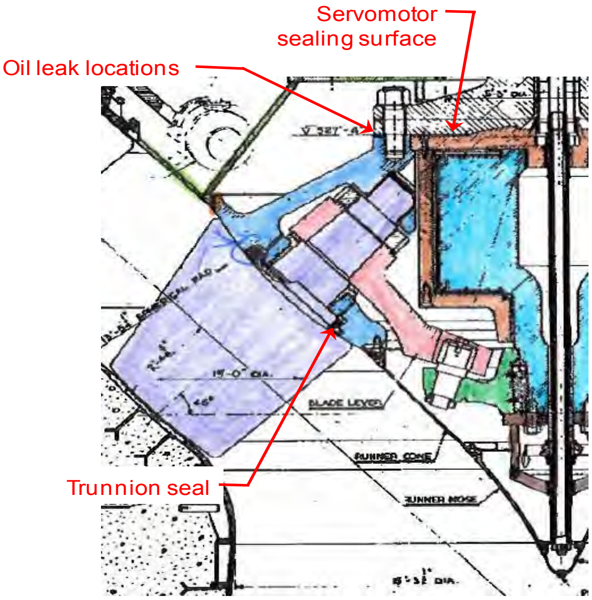
## Business Case Summary

**Part A: Business Need**

**Business Need:**

The primary driver for this project is to mitigate the environmental risk of a potential oil spill from a runner seal (trunnion seal) failure or oil leakage from the coupling flange between the runner and shaft. Other key drivers are to address reliability issues with major components and the risk of poor runner blade condition.

The following sketch is a section through the runner hub showing key runner components and leak locations. Refer to Appendix E for a full drawing of a PGS unit and the location of the runner assembly in relation to the entire unit.



Additional benefits to be gained from this project are:
- ensure reliable unit operation for 15 years
- opportunity to improve thrust bearing performance
- opportunity to improve the shaft seal on PG3

PG3 was selected as the first unit to be overhauled for the following reasons:
- long time since last overhaul (~15 years at 2013)
- worst internal oil leakage based on governor pump recycle time
- worst blade cavitation damage and blade profile
- still has the original 1957 design vulcanized trunnion seals

In accordance with the OPG standard investment management program, the Life Cycle Plan for the PGS is under development. Early assessment of the LCP indicates that it is favorable to invest in the overhaul on PG3. This does not commit OPG to investment in the remaining units until the LCP is approved.

SAB PGS is a six unit reversible pump-turbine plant capable of pumping water from the outlet of the tunnels and canal of the SAB complex, into a storage reservoir, and generating (174 MW capacity) from that reservoir by discharging the stored water back into the SAB Complex head pond. The station produces an average of 120 GWh/year. Also, there are a number of unique benefits that result from PGS operation which include:

1. Ability to pump water into storage at times of low demand, so that it can be later released for generation at times of high demand (peaking capability).
2. Level control for SAB1 and SAB2 head pond which allows the level to be adjusted for better unit efficiency.
3. Additional water that can be used for peaking at SAB1 and SAB2 - each PGS unit contributes up to 4,500 cfs to the SAB head pond when operating at maximum efficiency.

This unique operational profile results in more stops and starts than a conventional generating station as the units switch between pump and generation modes. In addition, units at the PGS are required to change blade pitch (often several times per minute) in response to the cross-over level controller, which contributes significantly to increased component wear. Because of the unique nature and operating characteristics of the PGS, the expected runner overhaul period is more frequent than conventional hydro units.

The original equipment manufacturer of the PGS vertical Deriaz runners was the English Electric Co. whose assets were purchased by Alstom. Alstom is now the only company which has access to the OEM construction drawings, specifications and procedures.

In 2008, PG6 was removed from service (only 9 years from its previous overhaul) due to oil seepage through the coupling flange between the runner and shaft. Attempts made to repair the leak without dismantling the unit were not successful. A complete overhaul of the unit was required to correct the deficiencies, which necessitated shipping the runner to the OEM. Key observations were made on the physical condition of a number of critical runner components during the PG6 overhaul and recommendations were made by Alstom, under the guidance of OPG's Technical Engineer.

There is the potential during the unit overhauls to find that the runner blades are not acceptable for use, either due to damage (cavitation, corrosion, cracking) or excessive deviation in blade profile. If the existing blades cannot be used, the unit would be forced out for 18+ months while a new set of blades are manufactured. To mitigate this risk, a set of blades was purchased for $2.8M as a Capital Spare under project SABP0040.

The current condition of the PG3 runner blades is not fully known. However, based on anecdotal history of blade damage, blade profile, and operational issues, the Engineering judgement is that the blades will not be acceptable for use. Therefore, the project is planning to replace the PG3 runner blades with the Capital Spare blades during the overhaul, and the new set of blades purchased under this project will be put back into inventory as the Capital Spare to protect the remainder of the overhaul program.

A Periodic Facility Condition Assessment (PFCA) for the PGS was completed in November 2010. Recommendations from the PFCA are being incorporated into the scope of work for this project and include:

1. Turbine - Inspect and correct all fits between the blade assembly and the servomotor assembly (PG6 scope).
2. Generator - Continue current program of NDT to monitor for cracks in the rotor and install telltales to monitor tightness of rims and effectiveness of the rim shrinks. Stator winding dog bones should be lashed.

The NPG 2013-15 Business Plan BURSA identified PGS unit reliability (forced outage due to oil leakage or generator rotor spider arm cracking) as one of five key business risks for the plant group. The mitigation plan for this risk is to perform the planned overhauls as per the approved business plan to address oil leakage issues, and to continue with the established NDE and repair program of the generator rotor.

The procurement strategy for the PG1-5 runner assemblies is to sole source the overhauls to Alstom with a scope of work similar to that performed for PG6. Included with the sole source justification is the supply and installation of new blades on each unit if required. The contract with Alstom will be structured to perform the overhaul on PG3, with options for overhaul of each of the remaining units. [redacted]

The Trades Work Assignment for the remaining project work was completed January 22, 2013. Disassembly, repairs to mechanical/electrical equipment and systems, installation of a PTFE thrust bearing, assembly, alignment, and commissioning was assigned to the PWU. The NPG Production department has committed to fully resourcing this work with PWU staff.

The BTU was assigned the installation of a new Fugesco seal, replacement of bearing cooling water piping, and installation of ultrasonic flow meters, an oil mist eliminator, and a kidney loop filtration system. The procurement strategy for the BTU assigned work is to competitively bid the work to general contractors approved by OPG. The contract will be structured to perform the work for PG3, with options for each of the remaining units.

A Project Definition Rating Index (PDRI) assessment was completed Mar.19, 2013. The result was a normalized PDRI score of 328 (out of 1000) which was desirable at this stage in the project life cycle. The team scored well on the basis of project decision but identified the basis of design as requiring additional definition. Finalization of the Tech Spec for the design and supply of the PTFE bearing, kidney loop filters, and oil mist removal system will address many of the less defined items.

**Part B: Preferred Alternative**

**Description of Preferred Alternative: Rehabilitate PG3**

Rehabilitate the existing PG3 runner, including repairing the servomotor, modify and/or replace seals and sealing surfaces, and other minor runner repairs as required. Install new runner blades. Complete other work on the unit that is consistent with a major overhaul and work consistent with the PFCA results.

The existing servomotor is not at end of life, is in acceptable condition, and can continue to be maintained.

The current condition of the existing runner blades is not fully known. However, based on anecdotal history of blade damage, blade profile, and operational issues, the Engineering judgement is that the blades will not be acceptable for use. Therefore, they will be replaced with new runner blades during the overhaul. If the blades are not replaced, the unit would require another long duration outage in approximately 7 years to fully disassemble the unit, inspect the runner blades, and re-assemble.

The existing generator rotor spider arms are not at end of life, are in acceptable condition, and can continue to be maintained.

The unit will be overhauled from September 2013 to July 2014.

This alternative will address the potential oil leak issue that currently exists on PG3, provide reliable unit operation for 15 years, and has the lowest estimated project cost.

| Deliverables: | Associated Milestones (if any): | Target Date: |
|---|---|---|
| Contract with Alstom finalized | P.O. issued to Alstom | May 24, 2013 |
| RFP process for general Contractor complete | P.O. issued to Contractor | Aug. 30, 2013 |
| PG3 taken out of service | Outage start | Sept. 17, 2013 |
| Overhaul work complete | PG3 RTS | July 15, 2014 |

**Part C: Other Alternatives**

**Base Case: Status Quo – No Project**

Continue to execute the existing LEM program for unit maintenance which does not include any unit disassembly. Maintenance costs will increase each year as the unit continues to wear.

This alternative is not acceptable as it does not address the runner seal issues and may lead to oil leakage or reduced pump/generator availability.

**Alternative 2: Rehabilitate PG3 including Replacement of Major Components**

Rehabilitate the existing PG3 runner by replacing the aging servomotor, replacing runner blades, and replacing/ modifying seals, sealing components and related surfaces. Replace the generator rotor spider. Complete other work on the unit that is consistent with a major overhaul and work consistent with the PFCA results.

The existing servomotor is not at end of life, is in acceptable condition, and can continue to be maintained. A like-for like replacement would provide no additional benefit.

The existing generator rotor spider arms are not at end of life, are in acceptable condition, and can continue to be maintained. Replacement with a new design that doesn't have the cracking issues would reduce maintenance but the high cost cannot be justified.

This alternative will address the potential oil leak issues that currently exist on PG3 and will provide a more efficient unit. However, the incremental efficiency benefit to be gained does not justify the higher project cost.

**Alternative 3: Replace Existing PG3 Runner, Overhaul Generator**

Complete runner, including servomotors and blades, would be replaced with a modern high efficiency unit. The efficiency increases gained would allow longer PG3 operation with existing generator and reservoir configuration.

This alternative requires a complete redesign of the PGS units and would take an estimated 2 years to redesign and another 1 to 2 years to install on the first unit. This will continue to leave the PGS at a high risk of a potential oil spill or oil leakage for at least 3-4 additional years.

Some design issues to consider are:
- shaft and rotor may be inadequate to handle higher stresses due to increased loading
- stator may not be able to handle the increased power from the unit
- major modifications may be required to install wicket gates

The estimated cost for this alternative is $15-20M per unit. This alternative is not recommended due to the high project cost.

**Alternative 4:**

# Type 3 Business Case Summary

**Part D: Project Cash Flows**

| k$ | LTD | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Future | Total |
|---|---|---|---|---|---|---|---|---|---|
| Currently Released | | | | | | | | | |
| Requested Now | - | 2,419 | 5,993 | 631 | | | | | 9,043 |
| Future Required | - | | | | | | | | |
| **Total Project Cost** | | 2,419 | 5,993 | 631 | | | | | 9,043 |
| Ongoing Costs | - | 0 | 0 | 0 | | | | | 0 |
| **Grand Total** | | 2,419 | 5,993 | 631 | | | | | 9,043 |

| | | | | | |
|---|---|---|---|---|---|
| **Estimate Class:** | Class 3 | **Estimate at Completion:** | 9,043 | **OAR Approval Amount:** | 9,043 |

**Additional Information on Project Cash Flows (optional):**

The 2013 budget includes funding of $1,200k OM&A for the PGS overhaul program. Changes will be managed within the Plant Group budget envelope.

**Part E: Financial Evaluation**

| k$ | Rehabilitate PG3 | Status Quo | Rehabilitate PG3 incl. Replace Major Components | Replace PG3 Runner, O/H Generator | |
|---|---|---|---|---|---|
| **Project Cost** | 9,043 | N/A | 14,000 | 20,000 | |
| **NPV (after tax)** | | | | | |
| **Other** | | | | | |

**Summary of Financial Model Key Assumptions (see Guidance on this Type 3 BCS Form):**

A Financial Evaluation was not completed for this project since this is sustaining work that was similarly performed on PG6.

Note that a Financial Evaluation of the PGS was performed as part of the PGS Reservoir Refurbishment project which is being managed by Hydro Development Engineering. In the Definition Phase BCS, the economic assessment showed that there is approximately a $470M net present value to the Ontario electricity system based on evaluation of capacity value and the peaking energy value of the ongoing operation of PGS compared to shutdown of the facility. This economic analysis was over a 50 year period and included overhauls of PG1-5.

Changes in the key assumptions since the Definition BCS was released in Sept 2011 are shown in the following table:

| $M | Def BCS | 2013 Forecast | Variance |
|---|---|---|---|
| Estimated cost of reservoir refurb project | 255 | 100 | (155) |
| Overhauls (5 units) | 25 | 29.5 | 4.5 |
| Runner blade replacement (6 units) | 15 | 16.8 | 1.8 |
| **Totals** | **285** | **146.3** | **(138.7)** |

Based on these changes, the economic assessment in the PGS Reservoir Refurbishment project Definition BCS is still valid.

**Part F: Qualitative Factors**

Ensure availability of PG3 to preserve the ability to time shift water from off-peak to peak periods.

**Part G: Risk Assessment**

| Risk Class | Description of Risk | Risk Management Strategy | Post-Mitigation | |
|---|---|---|---|---|
| | | | Probability | Impact |
| Cost | Costs higher than expected | Allowances have been included in the RQE for known unknowns. This will be relinquished as necessary during the project. Contingency ([redacted]) included. | Low | Low |
| Scope | Discovery work | The scope was prepared based on PG6 work scope in 2008 and PFCA recommendations. Allowances have been made for repairs based on findings. | Medium | Low |
| Schedule | Delays to project schedule if PWU crews pulled off project work. | Commitment from Production to provide adequate resources. | Low | Medium |
| Resources | Maintenance crews pulled off project work to perform other priority work | Commitment from Production to provide adequate resources. A proper resource plan needs to be developed. An overhaul crew will be formed. | Low | Medium |
| Quality/ Performance | Poor quality of work | An ITP will be developed for testing, start-up, and commissioning. | Low | Low |
| Technical | Improvements to turbine shaft seal and coupling bolt/stud seals don't work | Changes to match PG6 modifications. Alstom to pressure test servomotor and assembled runner hub to guarantee against leaks for a period of 10 years | Low | Medium |
| Cost | OM&A costs higher due to repairing instead of replacing runner blades | Accept increased OM&A costs.<br>New PG3 set of blades becomes a spare for the rest of the program. | Low | Low |
| Schedule | Overhaul work during winter months, delays due to poor weather when hatch covers are open (craning) | There is sufficient time and flexibility in the schedule to manage these delays. | Low | Low |
| Technical | New design of thrust bearing (using PTFE) does not work or fails | PES prepare tech spec and provide technical assistance during install and commissioning.<br>If it fails, replace with existing design and don't use on other units. | Medium | Low |
| Technical | Alternate design of trunnion seal by Alstom | If a new seal cannot be designed, all seals will be replaced with the design used on PG6.<br>If a new design can be provided, it is to be guaranteed for 10 years. OPG will have to decide if this is a risk we want to accept. | Medium | Medium |
| Environment | Oil spills during the overhaul | Use NPG approved instructions. | Low | Low |

**Additional Risk Analysis:**

**Part H: Post Implementation Review (PIR) Plan**

| Type of PIR | Target Project In Service Date | Target PIR Completion Date |
|---|---|---|
| Simplified | July 15, 2014 | December 30, 2015 |

| Measurable Parameter | Current Baseline | Target Result | How will it be measured? | Who will measure it? (person/group) |
|---|---|---|---|---|
| Runner assembly oil leakage | < 300 mL/day | 0 mL/day | Pressure test at Alstom facility | NPG & PES Tech Support Engineers |
| Unit internal oil leakage | 49 gal/min | < 25 gal/min | Readings per PGS Leakage Assess | NPG Tech Support Engineer |
| Correct fabrication of set of runner blades and transfer to Cap. Spare asset class | N/A | As per drawings and tech specifications | Inspections as per QA/QC programs | PES Tech Support, Asset Engineer |

**Part I: Definitions and Acronyms**

| | |
|---|---|
| ITP - | Inspection & Test Plan |
| LCP - | Life Cycle Plan |
| LEM - | Leading Edge Maintenance |
| NDE - | Non-Destructive Examination |
| NDT - | Non-Destructive Test |
| NPG - | Niagara Plant Group |
| PES - | Plant Engineering Services |
| PFCA - | Periodic Facility Condition Assessment |
| PGS - | Pump Generating Station |
| PTFE - | Polytetrafluoroethylene - a synthetic fluoropolymer of tetrafluoroethylene that finds numerous applications. The best known brand name of PTFE is Teflon. |
| RQE - | Release Quality Estimate |
| SAB - | Sir Adam Beck |

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# Type 3 Business Case Summary

## Appendix A: Summary of Estimate

| | | | |
|---|---|---|---|
| **Project Number:** | SABP0053<br>SABP0056 | **Facility:** | SAB PGS (NF282) |
| **Project Title:** | P-G3 Overhaul / New Runner Blades | | |

**Estimated Cost in** k$

| | LTD | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Future | Total | % |
|---|---|---|---|---|---|---|---|---|---|---|
| **OPG Project Management** | | 68 | 97 | | | | | | 165 | 1.8 |
| **OPG Engineering** | | 16 | 16 | | | | | | 32 | 0.35 |
| **Permanent Materials** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Design and Construction** | | 330 | 670 | | | | | | 1,000 | 11.1 |
| **Consultants** | | | | | | | | | | |
| **Other Contracts / Costs** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Interest** | | 5 | 20 | 7 | | | | | 32 | 0.35 |
| **Subtotal** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Contingency** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Total** | | **2,419** | **5,993** | **631** | | | | | **9,043** | **1.0** |
| **Removal Costs Included** | | | | | | | | | | |

**Note:** All estimates shown in the table are for the combined OM&A and Capital portions. For breakdowns of OM&A and Capital estimates, refer to the individual RQE's.

## Notes

| | | | |
|---|---|---|---|
| **Project Start Date** | 2013-09-17 | **Project Completion or In-Service Date** | 2014-07-15 |
| **Interest Rate** | 5% | **Escalation Rate** | 0% |
| **Definition Cost Included** | $0 k | **Estimate at Completion** | $9,043 k |

| **Prepared by:** | **Approved by:** |
|---|---|
| Greg Young<br>Project Officer 2013-04-30 | Dan Roorda<br>Section Manager, Projects 2013-04-30 |

# Type 3 Business Case Summary

**Appendix B: Comparison of Total Project Estimates**

| Phase | Release | Date (YYYY-MM-DD) | Total Project Estimate in k$ (by year including contingency) | | | | | | Later | Total Project Estimate |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
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| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |

**Project Variance Analysis**

**Estimated Cost in** k$

| k$ | LTD | Total Project | | Variance | Comments |
|---|---|---|---|---|---|
| | | Last BCS | This BCS | | |
| **OPG Project Management** | | | 165 | n/a | This is a new project.<br>All estimates shown in the table are for the combined OM&A and Capital portions. For breakdowns of the OM&A and Capital estimates, refer to the individual RQE's. |
| **OPG Engineering** | | | 32 | n/a | |
| **Permanent Materials** | [redacted] | [redacted] | [redacted] | n/a | |
| **Design and Construction** | | | 1,000 | n/a | |
| **Consultants** | | | | | |
| **Other Contracts/Costs** | [redacted] | [redacted] | [redacted] | n/a | |
| **Interest** | | | 32 | n/a | |
| **Subtotal** | [redacted] | [redacted] | [redacted] | n/a | |
| **Contingency** | [redacted] | [redacted] | [redacted] | n/a | |
| **Total** | | | **9,043** | n/a | |
| **Removal Costs Included** | | | | | |

**Appendix C: Financial Evaluation Assumptions**

Key assumptions used in the financial model of the Project are (complete relevant assumptions only):

**Project Cost:**

(1)
(2)
(3)

**Financial:**

(1)
(2)
(3)

**Project Life:**

(1)
(2)
(3)

**Energy Production:**

(1)
(2)
(3)

**Operating Cost:**

(1)
(2)
(3)

**Other:**

(1)
(2)
(3)

Attach further detail as appropriate from the Financial Evaluation spreadsheet.

**Refer to SAB PGS Reservoir Refurbishment Definition BCS**

**Appendix D: References**

PGS Periodic Facility Condition Assessment (Report No. R-NF282-01557-0003) dated November 2010

Definition Phase Project Charter for SABP0036 approved December 18, 2012

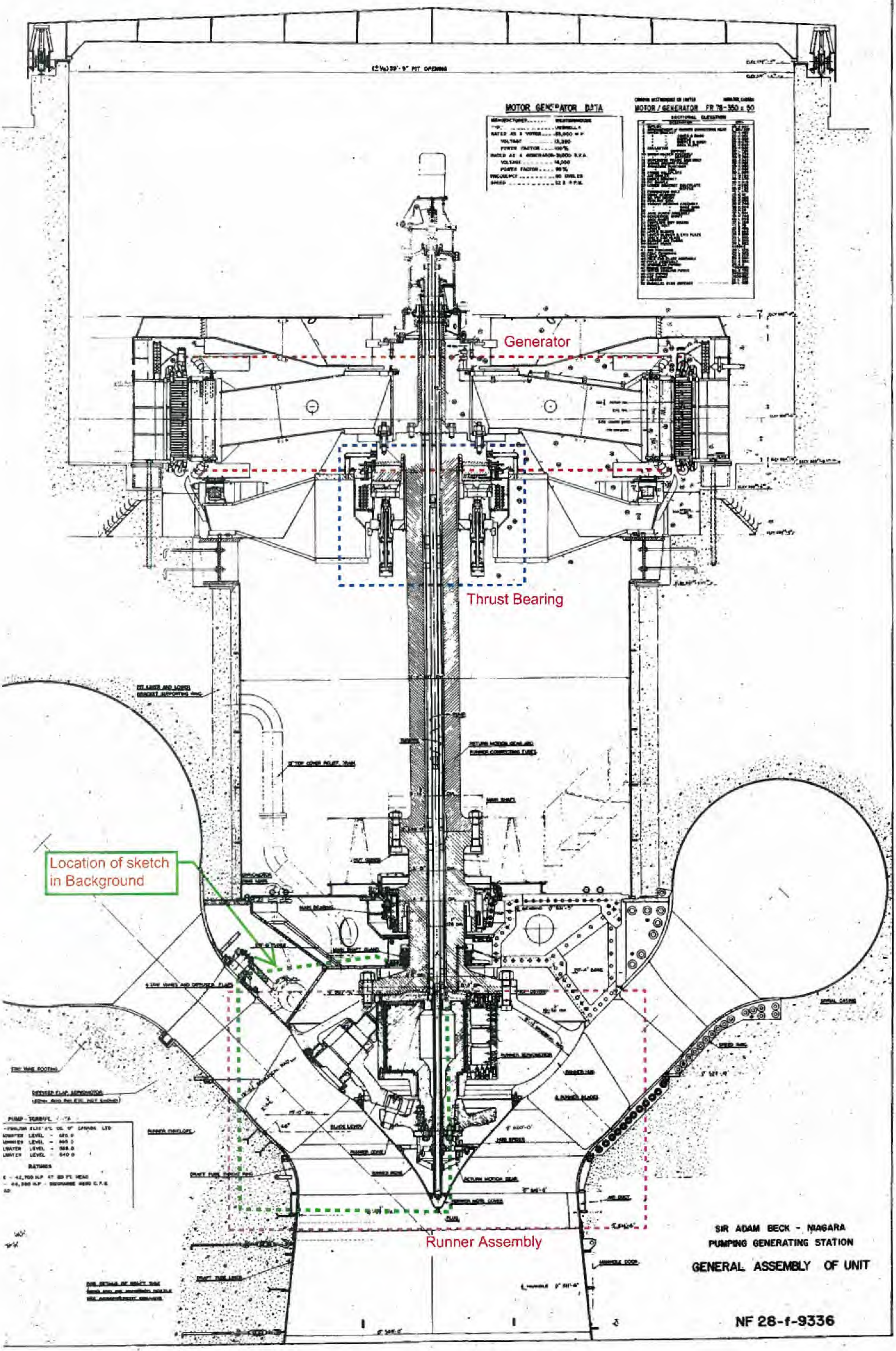
Business Plan 2013-2015

SAB PGS Reservoir Refurbishment Definition BCS (R-NF282-08707.021-0002) approved September 19, 2011

Release Quality Estimates - OM&A and Capital

Initial Project Execution Plan

## Appendix E: PGS Full Unit Drawing



SIR ADAM BECK - NIAGARA
PUMPING GENERATING STATION

GENERAL ASSEMBLY OF UNIT

NF 28-f-9336

ONTARIOPOWER GENERATION

**Niagara Plant Group**

**RELEASE QUALITY ESTIMATE (RQE)**
Summary Sheet (K$)

| | |
|---|---|
| Date: | 11-Apr-13 |
| Estimate #: | |

**PROJECT CLASSIFICATION:** OM&A
**PROJECT NUMBER:** SABP0053
**FACILITY:** Pump Generating Station
**PROJECT DESCRIPTION:** PGS Unit 3 Rehabilitation

## Estimated Cost Summary (K$)

| Project Components | TOTAL EST. | 2013 | 2014 | 2015 | 2016 | 2017 | Future Years | % |
|---|---|---|---|---|---|---|---|---|
| **Removal Costs** | | | | | | | | |
| **Contingency** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Interest** | | | | | | | | |
| **Development Spending** | | | | | | | | |
| **Execution Phase (Summary)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Project Management | 153 | **56** | 97 | | | | | **2.4%** |
| Engineering | 32 | **16** | 16 | | | | | **0.5%** |
| Materials | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| External Purchase Services | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| PWU Charges | 1,000 | **330** | 670 | | | | | **15.8%** |
| **TOTAL** | **6,342** | **1,995** | **4,347** | | | | | **1** |

**SUMMARY: Basis of Estimate**

**Scope:**

**Rehabilitate the existing PGS Unit 3 runner, including replacing the runner blades, repairing the servomotor, modify and/or replace seals and sealing surfaces, and other minor runner repairs as required. Complete other work on the unit that is consistent with a major overhaul and work consistent with PFCA results. This scope will address the potential oil leak issues that currently exist and provide reliable unit operation for 10 to 15 years.**
**This estimate is based on information compiled from the PGS Unit 6 overhaul, project SABP0030 with actuals equaling 4,577K and from experienced personnel who worked on and were involved with the PG6 overhaul. The new runner blades will be provided to the project through project # SABP0056, PG3 New Runner Blades.**
**This RQE value is more than the PGS 6 Rehabilitation cost due to added [redacted] escalation cost per year, an allowance for parts procurement and contingency.**

**Conditions/Assumptions:**

**Allowances have been included in the contingencies for work processes that have changed since PGS U 6 was overhauled and also to accommodate a workforce learning curve with the PWU crew, as most are new.**
**The schedule relies on the NPG machining facility and Alstom providing the required services as shown on the project schedule.**

**Schedule:**
Start Date: Monday, September 16, 2013
Project In-Service Date: Friday, July 11, 2014

**Back up documents attached:**

☐ Contractor Quote
☐ Project Schedule
☐ Labour Estimate
☐ Shop Services Estimate
☐ Other (description) ____
☐ Other (description) ____

**Prepared by:**

APRIL 11/13
Greg Young — Date
Project Engineer/Officer

**Approved by:**

Apr. 15/13
Dan Roorda — Date
Section Manager, Projects

**Estimate conforms to AACE - Class 3**
**OPG Governance applicable to the preparation of this document ETS-PM-STD-006; HY-HD-STD-06; OPG-PROC-0050**

**ONTARIOPOWER GENERATION**

**Niagara Plant Group**

**RELEASE QUALITY ESTIMATE (RQE)**
Summary Sheet (K$)

Date: **18-Apr-13**
Estimate #:

**PROJECT CLASSIFICATION:** CAPITAL
**PROJECT NUMBER:** SABP0056
**FACILITY:** SAB PGS (NF282)
**PROJECT DESCRIPTION:** PG3 New Runner Blades

## Estimated Cost Summary (K$)

| Project Components | TOTAL EST. | 2012 LTD | 2013 | 2014 | 2015 | 2016 | Future Years | % |
|---|---|---|---|---|---|---|---|---|
| **Removal Costs** | | | | | | | | |
| **Contingency** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Interest** | 32 | | 5 | 20 | 7 | | | 1.2% |
| **Development Spending** | | | | | | | | |
| **Execution Phase (Summary)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Project Management | 12 | | 12 | | | | | 0.4% |
| Engineering | | | | | | | | |
| Materials | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| External Purchase Services | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| PWU Charges | | | | | | | | |
| **TOTAL** | 2,701 | | 424 | 1,646 | 631 | | | 1 |

**SUMMARY: Basis of Estimate**

**Scope:**

Supply of one set of PGS runner blades to replace capital spare installed on PG3.

**Conditions/Assumptions:**

This estimate is based on a quotation from Alstom (Rev.2) received Jun.14, 2012. The quotation included options for up to 6 additional sets of blades.

Contingency of [redacted] was included for potential price changes.

**Schedule:**

Start Date: Tuesday, July 02, 2013
Project In-Service Date: Tuesday, March 17, 2015

**Back up documents attached:**

☑ Contractor Quote
☐ Project Schedule
☐ Labour Estimate
☐ Shop Services Estimate
☐ Other (description) ____
☐ Other (description) ____

**Prepared by:**

Apr. 30/13
Greg Young
Project Engineer/Officer
Date

**Approved by:**

Apr. 30/2013
Dan Reorda
Section Manager, Projects
Date

**Estimate conforms to AACE - Class 3**
**OPG Governance applicable to the preparation of this document ETS-PM-STD-006; HY-HD-STD-06; OPG-PROC-0050**

Filed: 2013-09-27
EB-2013-0321
Ex. F2-1-1
Attachment 2

# 2013-2015 NUCLEAR BUSINESS PLAN

## May 16, 2013

**Wayne Robbins, Chief Nuclear Officer**

OPG CONFIDENTIAL

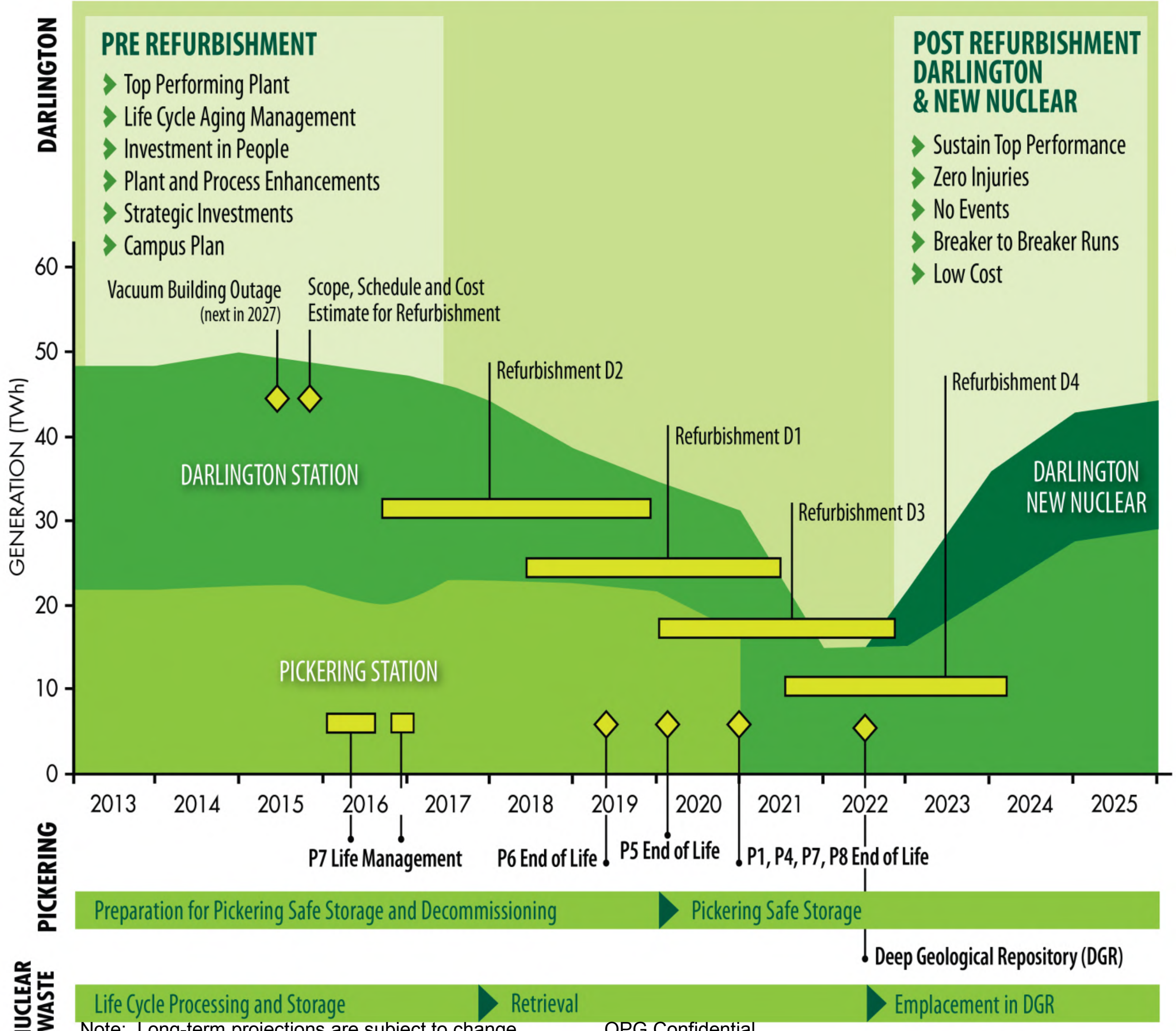
Filed: 2013-09-27
EB-2013-0321
Ex. F2-1-1
Attachment 2

# Nuclear Strategic Framework

PEOPLE POWERING THE FUTURE
OPG NUCLEAR

## Nuclear Cornerstones for Excellence

• **Safety** • **Reliability** • **Value for Money** • **Human Performance**



### PRE REFURBISHMENT

- Top Performing Plant
- Life Cycle Aging Management
- Investment in People
- Plant and Process Enhancements
- Strategic Investments
- Campus Plan

### POST REFURBISHMENT DARLINGTON & NEW NUCLEAR

- Sustain Top Performance
- Zero Injuries
- No Events
- Breaker to Breaker Runs
- Low Cost

2013

## STRATEGIC OBJECTIVE

Operate in a safe, efficient and cost effective manner, with prudent investments to improve reliability and lower production costs.

## STRATEGIC INITIATIVES

- Initiatives that close gaps to industry top performance.
- Darlington Top Performance.
- Pickering Ready and Reliable by 2015.
- Improve fleet outage performance.
- Continue to be industry leaders in Nuclear project management.
- Implement Engineering/Procurement/Construction strategy.

## BEHAVIOURS

- Integrate and Collaborate.
- Think Top and Bottom Line.
- Simplify It.
- Say It. Do It.
- Tell It As It Is.

ONTARIO POWER GENERATION

Note: Long-term projections are subject to change.

OPG Confidential

# Nuclear Operations - Executive Summary

The 2013-2015 OPG Nuclear Operations Business Plan is the first plan to reflect the Corporate Business Transformation (BT) initiative (Phase I). Its immediate objective is to ensure the safe and successful implementation of the 2012-2014 Business Plan, while moving towards the BT end state. Plan highlights include:

- Sustaining high performance levels in Safety and Human Performance through improvement opportunities and continued emphasis on supervisory effectiveness and development programs.
- Extending the operating life of Pickering units to 247k Equivalent Full Power Hours (EFPH).
- Slight reduction in generation plan from the previous plan largely due to additional outage and inspection scope required to extend Pickering's operating life to 247k EFPH. Generation plan includes advancing outage scope from Darlington planned outage in 2017 to 2014 (and 2015). Pickering generation plan optimized through selective reduction in feeder replacement outage scope.
- Improving the reliability of critical equipment at Pickering station, leading to a Forced Loss Rate of 5.5% in 2015, which represents a step change in performance.
- Maintaining top quartile performance at Darlington which supported the excellent safety and performance evaluation from the World Association of Nuclear Operators.
- Continue preparations at Darlington for the start of Refurbishment in October 2016 and for the Vacuum Building Outage in 2015.
- Staffing plan reductions, through detailed attrition modeling and changes to the workforce development program, and meeting objectives by simplifying and integrating processes.
- As a result of this plan, OPG Nuclear will support Business Transformation over the planning period, leading to a more sustainable cost structure, and continue to deliver on its mission of proudly generating clean, safe, low cost electricity through dependable performance.

# Nuclear Operations - Planning Assumptions

**Pickering**

- Continued Operations will extend the operating life of Pickering units to 247k EFPH. Unit 6 will operate to 2019 and Units 1, 4, 5, 7 and 8 will operate to 2020.

**Darlington**

- Refurbishment begins with Unit 2 in October 2016 and ends in February 2024. Refurbishment outages are 36 months each for Units 2, 1, 3, and 4, with a 16 - 19 month overlap between units. Darlington continues driving towards top industry performance post-refurbishment.
- There is a Vacuum Building Outage (VBO) in 2015, eliminating the need for a VBO in 2021 during the refurbishment window. The frequency of VBOs and Station Containment Outages will be changed to once every 12 years (CNSC approval still required).
- Work originally planned for the D1711 outage will be advanced to 2014-2015 to minimize 2017 outage duration.

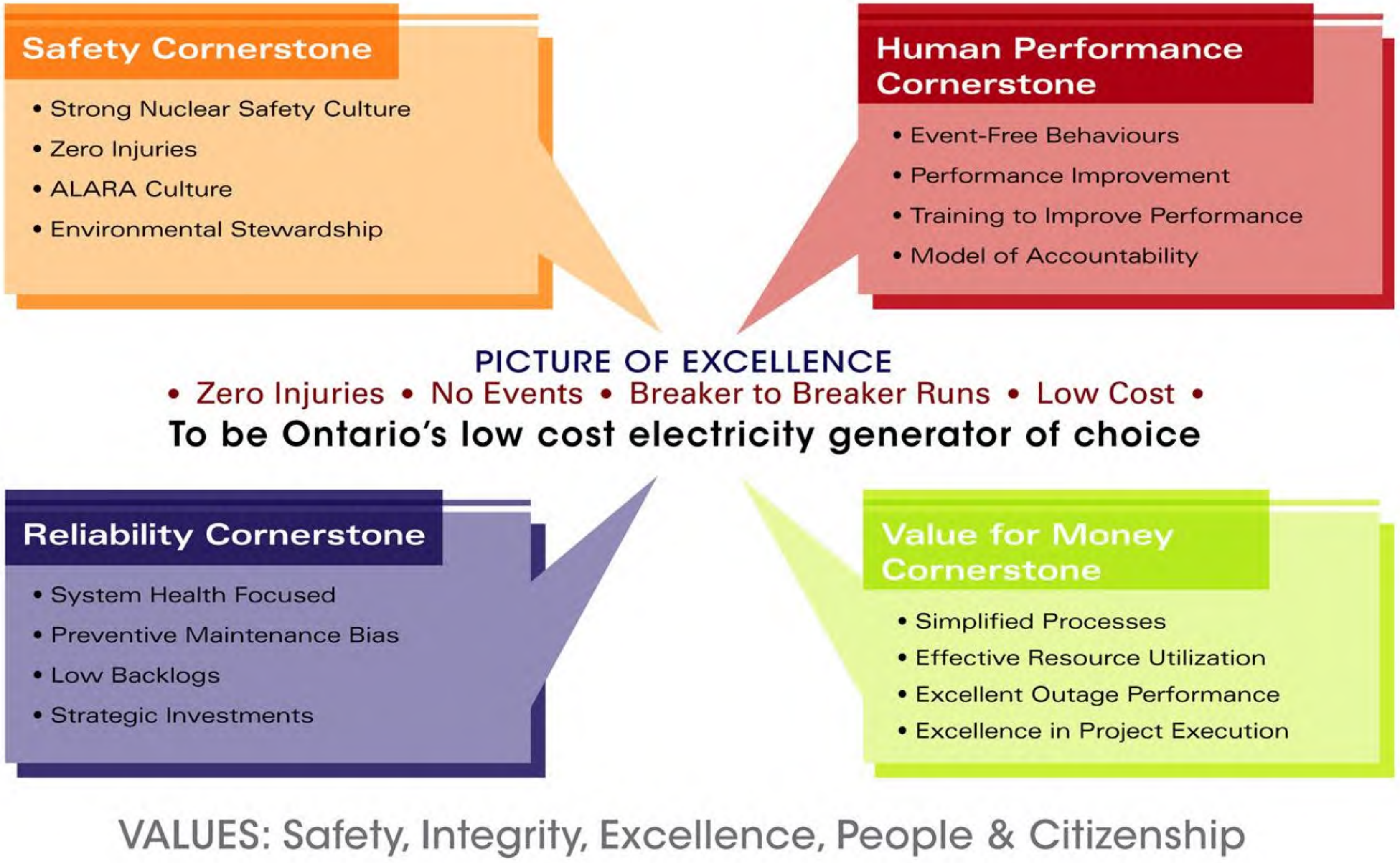
**Nuclear Waste Management**

- Increased production targets of Dry Storage Containers (DSCs) at the Darlington and Pickering Waste Management Facilities will be maintained with no additional staff increases.
- The Low and Intermediate Level Waste Deep Geological Repository (DGR) is delayed by 3 years.

**Nuclear Support**

- Improvements and organizational changes will be made to fully implement Business Transformation Initiatives and business efficiencies from the centre-led model over the next 3 years.
- Project portfolio investments align with end of life and refurbishment assumptions at both sites.
- CNSC licenses will transition to 10-year terms during 2013-2015 (Darlington and Darlington Waste Management Facility).
- Workforce development is focused primarily on Operator development to meet Nuclear demands to ensure an adequate number of fully qualified operators.

# Nuclear Cornerstones



**Safety Cornerstone**

- Strong Nuclear Safety Culture
- Zero Injuries
- ALARA Culture
- Environmental Stewardship

**Human Performance Cornerstone**

- Event-Free Behaviours
- Performance Improvement
- Training to Improve Performance
- Model of Accountability

**PICTURE OF EXCELLENCE**

• Zero Injuries • No Events • Breaker to Breaker Runs • Low Cost •

**To be Ontario's low cost electricity generator of choice**

**Reliability Cornerstone**

- System Health Focused
- Preventive Maintenance Bias
- Low Backlogs
- Strategic Investments

**Value for Money Cornerstone**

- Simplified Processes
- Effective Resource Utilization
- Excellent Outage Performance
- Excellence in Project Execution

VALUES: Safety, Integrity, Excellence, People & Citizenship

# Nuclear Operations - Issues and Focus Areas

**Fleet**

- Continue improving work protection practices.
- Enforce accountability and leadership delegation. (“Say it. Do it.”)
- Improve outage preparation and performance execution.
- Improve chemistry performance of the operating reactors (2013-NFI-03).
- Corrective Maintenance backlog reduction (2013-NFI-04).
- Develop strong relationships with the centre-led functions.

**Pickering**

- Continue to reduce Collective Radiation Exposure (2013-NFI-01).
- Continue to improve Forced Loss Rate (2013-NFI-02).
- Execute the Reliability Improvement Plan and achieve a step change in performance (5.5% FLR) by 2015.
- Execute Continued Operations work programs. Focus on Minor Modification improvements and design legacy issues.
- Renew the station operating license as one site in 2013.

**Darlington**

- Integrate and align with the Refurbishment Project, resulting in approved scope, strategic investments and staffing.
- Implement mitigation activities to prevent derating from Heat Transport System aging.
- Increase licensed staff training throughput to maintain target levels for authorized staff.

**Nuclear Waste**

- Process and store annual commitment of Dry Storage Containers and Low Level Waste in alignment with station generation targets. Execute waste strategy with a focus on reducing Low and Intermediate Level radioactive waste and the environmental footprint.
- Investigate and, where feasible, execute Used Fuel long-term potential cost reduction initiatives.
- Maintain Safety and Environment Certifications, and improve Fire Protection Program and Systems.

**Nuclear Support**

- Nuclear Engineering – Implement an effective centre-led Engineering management structure and accountability.
- Nuclear Services – Provide effective and efficient Radiation Protection Services, Regulatory Affairs, Strategic Planning and Benchmarking, Environmental Assessments and Stakeholder Relations through centre-led functions.
- Operations and Maintenance Support – Enable improved fleet performance through: leadership, direction setting and performance monitoring, process improvement, collaboration, and partnership.
- Security and Emergency Services – Ensure OPG is prepared for, can respond to, and recover from emergencies.

# Nuclear Operations - Generation Plan

| | 2013 | 2014 | 2015 |
|---|---|---|---|
| **Pickering Nuclear** | | | |
| Net Generation in TWh | 21.1 | 21.3 | 21.9 |
| Planned Outage Days | 304 | 293 | 288 |
| Forced Loss Rate % | 8.1 | 7.8 | 5.5 |
| Unit Capability Factor % | 79.2 | 79.9 | 82.1 |
| **Darlington Nuclear** | | | |
| Net Generation in TWh | 26.9 | 28.4 | 26.1 |
| Planned Outage Days | 144 | 77 | 188 |
| Forced Loss Rate % | 1.5 | 1.3 | 1.0 |
| Unit Capability Factor % | 88.8 | 93.5 | 86.3 |
| **OPG Nuclear** | | | |
| Net Generation in TWh | 48.0 | 49.7 | 48.0 |
| Planned Outage Days | 448 | 370 | 476 |
| Forced Loss Rate % | 4.5 | 4.1 | 3.1 |
| Unit Capability Factor % | 84.3 | 87.2 | 84.3 |

**Highlights**

- The Generation Plan maintains Nuclear's planned production level in 2013 from the previous plan. In 2014 planned production level decreases by 0.1 TWh, from the previous plan, due to additional inspection and outage work required to extend Pickering's operating life to 247k EFPH.
- Reliability of critical equipment at Pickering station will be improved, resulting in a step change in performance by 2015 (i.e., FLR target of 5.5%).
- Pickering's Net Generation in TWh reflects additional planned outage days for Continued Operations. The impact on 2013 and 2014 is -0.7 TWh in each year.
- There are two Darlington planned outages in 2013.
- A significant portion of the planned D1711 outage work has been advanced to 2014 and 2015 to minimize 2017 outage duration during Darlington Refurbishment.

# Nuclear Operations – 3 Year Performance Targets

## 2011

| | 2011 Actuals (Rolling Average) | |
|---|---|---|
| **Metric** | **Pickering** | **Darlington** |
| **Safety** | | |
| All Injury Rate (#/200k hours worked) | 🟩 0.31 | 🟩 0.18 |
| Industrial Safety Accident Rate (#/200k hours worked) | 🟩 0.04 | 🟩 0.09 |
| Collective Radiation Exposure (Person-rem per unit) | ⬜ 110.07 ⇧ | 🟩 71.12 |
| Airborne Tritium Emissions (Curies) per Unit | ⬜ 2,565 | 🟩 969 |
| Fuel Reliability Index (microcuries per gram) | 🟩 0.000175 ⇧ | 🟥 0.001133 ⇩ |
| Reactor Trip Rate (# per 7,000 hours) | 🟥 0.60 ⇩ | 🟩 0.21 |
| Auxiliary Feedwater System Unavailability (#) | 🟩 0.0044 | 🟩 0.0000 |
| Emergency AC Power Unavailability (#) | 🟩 0.0107 | 🟩 0.0067 |
| High Pressure Safety Injection Unavailability (#) | 🟩 0.0001 | 🟩 0.0000 |
| **Reliability** | | |
| WANO NPI (Index) | 🟥 66.1 | 🟩 92.8 |
| Forced Loss Rate (%) | 🟥 10.34 | ⬜ 1.80 |
| Unit Capability Factor (%) | 🟨 72.5 | ⬜ 89.6 |
| Chemistry Performance Indicator (Index) | 🟥 1.10 | 🟨 1.03 |
| On-line Deficient Maintenance Backlog (work orders per unit) | ⬜ 301 | ⬜ 266 |
| On-line Corrective Maintenance Backlog (work orders per unit) | 🟥 160 | 🟥 121 |
| **Value for Money** | | |
| Total Generating Cost per MWh ($ per Net MWh)[1] | 🟥 65.86 | 🟩 33.05 ⇧ |
| Non-Fuel Operating Cost per MWh ($ per Net MWh)[1] | 🟥 56.54 | 🟨 26.42 |
| Fuel Cost per MWh ($ per Net MWh)[1] | 🟩 4.27 | 🟩 4.24 |
| Capital Cost per MW DER (k$ per MW)[1, 2] | 🟩 32.54 | 🟩 18.54 |
| **Human Performance** | | |
| Human Performance Error Rate (# per 10k ISAR hours) | ⬜ 0.007 ⇧ | ⬜ 0.006 ⇩ |

- Continue to lead industry in overall conventional and nuclear safety performance, with top quartile performance from both stations. Plan in place at Darlington to address fuel defects.
- Focus on work order readiness, reducing backlogs, improving maintenance effectiveness, and work management to improve reliability of the units. Execute the approved Nuclear Fleet Initiatives.
- Pickering continue to benefit from organizational efficiencies through Pickering site amalgamation and implementation of value for money initiatives. Continue focusing on value for money and outage cost reductions at Darlington.
- Darlington's 2015 TGC/MWh and NFOC/MWh are higher as a result of the planned VBO/SCO.
- Minimize the number of event free day resets through improved use of event free tools, oversight, and dynamic learning activities.

## 2015

| 2015 Target Guidelines (Annual) | |
|---|---|
| **Pickering** | **Darlington** |
| | |
| 🟩 0.89 | 🟩 0.89 |
| 🟩 0.15 | 🟩 0.15 |
| ⬜ 98.71 | 🟩 73.80 |
| ⬜ 1,800 | 🟩 1,000 |
| 🟩 0.000500 | 🟩 0.000500 |
| 🟩 0.50 | 🟩 0.50 |
| 🟩 0.0200 | 🟩 0.0200 |
| 🟩 0.0250 | 🟩 0.0250 |
| 🟩 0.0200 | 🟩 0.0200 |
| | |
| 🟨 74.2 | 🟩 96.1 |
| 🟨 5.50 | 🟩 1.00 |
| 🟨 82.1 | ⬜ 86.3 |
| 🟨 1.04 | 🟩 1.01 |
| 🟩 < 197 | 🟩 180 |
| 🟨 78 | 🟩 25 |
| | |
| 🟥 60.25 | ⬜ 42.78 |
| 🟥 53.34 | 🟥 32.82 |
| 🟩 5.93 | 🟩 5.28 |
| 🟩 6.98 | 🟩 34.82 |
| | |
| 🟩 0.004 | 🟩 0.004 |

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[1] TGC/MWh and NFOC/MWh targets exclude OPEB, Pension, and Corporate Asset Service Fees to align with industry standards.

[2] DER - Design Electrical Rating.

⇩ Declining Benchmark Quartile Performance vs. 2010
⇧ Improving Benchmark Quartile Performance vs. 2010

Green = max NPI points achieved (if applicable) or best quartile performance
White = 2nd quartile performance
Yellow = 3rd quartile performance
Red = worst quartile performance

# Pickering - Executive Summary

The vision for Pickering Nuclear is to be *"Ready and Reliable by 2015"* to ensure that the station delivers the needed power as Darlington units are taken offline for refurbishment.

The Approved Plan, including planned reliability improvements, is on track and is achieving the results as originally predicted.

This plan reflects a commitment to achieve further improvements relative to staffing, financial and operational targets.

- Revenues will be increased by improving equipment reliability and reducing the Forced Loss Rate (FLR) to 5.5% in 2015.
- Revenues will be further increased by extending the life of the station to 2020 through the successful completion of the Continued Operations work program.
- Costs will be reduced by improving productivity through implementation of station initiatives such as Days Based Maintenance and Work Management Restructuring.
- Favourable WANO evaluation results will be attained and the operating license will be renewed as one Site for the first time in 2013.
- High safety standards will be achieved by consolidating expertise and successfully qualifying staff, restoring plant conditions, and establishing controls on asbestos.

**Key Operating Assumptions**

- Each unit will be operated up to 247k Equivalent Full Power Hours.
- Unit 6 will operate to 2019. The remaining five units will operate to 2020.
- Improved equipment reliability, resulting in reduction in FLR to 5.5% in 2015.

# Pickering - Major Focus Areas

## SAFETY

- Renew the operating license as one Site in 2013
- Restore plant condition
- Execute an effective asbestos abatement program
- Improve work protection performance
- Further reduce tritium emissions
- Minimize collective radiation exposure through improved work practices, ALARA mentoring, and improved Fuelling Machine filtration
- Implement Fukushima emergency response readiness

## HUMAN PERFORMANCE

- Achieve favourable WANO evaluations
- Enhance authorized staff hiring and through-put to meet short and long term demands
- Implement Corrective Action Plan improvement including improving quality of root cause analyses
- Improve operator fundamentals, reduce operator challenges and improve plant status control
- Improve leadership, accountability, and supervisory effectiveness
- Implement the Maintenance Critical Work Quality Program

## RELIABILITY

- Execute the Reliability Improvement Plan and achieve a step change in performance (5.5% FLR) by 2015
- Execute the Continued Operations work program
- Resolve recurring equipment failures, including fuel handling systems and turbine governor
- Drive maintenance backlogs down
- Focus on Minor Modifications improvements and fix design legacy issues

## VALUE FOR MONEY

- Shift to Days Based Maintenance
- Restructure work management and improve preparations and adherence to process responsibilities
- Maintain strict controls and accountability on outage scope, schedule and cost, including continued operations
- Improve outage execution
- Improve parts availability through smart ordering and through a strategic spares initiative

# Pickering - 2013-2015 Equipment Reliability Plan

**Problem Statement**

- Pickering must be “ready and reliable by 2015” in order to deliver needed power as Darlington undergoes refurbishment.
- Pickering Nuclear FLR performance does not meet expectations, in particular Units 1, 4, and 8.
- Work Order Backlogs (On-line Corrective and Deficient Maintenance) are highest on Units 1, 4, and 8.

**Objective**

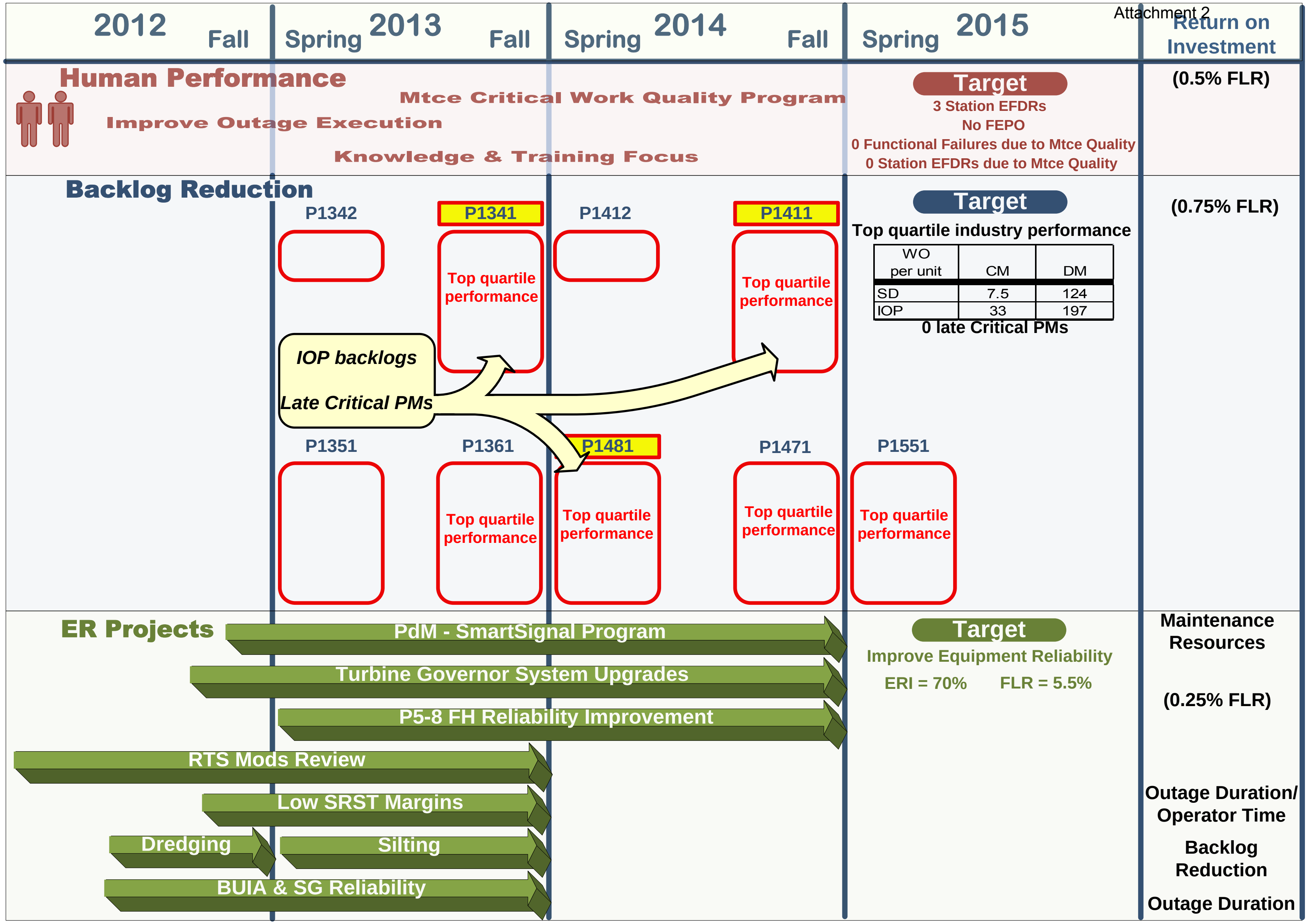
- Define and execute a plan to achieve an incremental reduction of Pickering Nuclear FLR to 5.5% in 2015

**Pickering Nuclear Plan for 5.5% FLR - Summary**

- The plan has three main elements:
    - Human Performance Improvement
    - Targeted backlog reduction
    - Execution of Equipment Reliability Projects

- The priority for the targeted backlog reduction is with Units 1, 4, and 8.
- Projection is for the additional scoping and completion of up to 250 Work Orders per outage.
- Investment and costs included in this business plan:
    - Targeted backlog reduction - $11M ($3M for 2013, $6M for 2014, $2M for 2015)
    - P5-8 Fuel Handling Reliability project - $29M
    - Equipment Reliability initiatives -$5M

# Pickering - Plan for 5.5% FLR



2012 Fall | Spring 2013 Fall | Spring 2014 Fall | Spring 2015 | Return on Investment

**Human Performance**

Mtce Critical Work Quality Program

Improve Outage Execution

Knowledge & Training Focus

**Target**

3 Station EFDRs

No FEPO

0 Functional Failures due to Mtce Quality

0 Station EFDRs due to Mtce Quality

(0.5% FLR)

**Backlog Reduction**

P1342

P1341 Top quartile performance

P1412

P1411 Top quartile performance

*IOP backlogs*

*Late Critical PMs*

P1351

P1361 Top quartile performance

P1481 Top quartile performance

P1471 Top quartile performance

P1551 Top quartile performance

**Target**

Top quartile industry performance

| WO per unit | CM | DM |
|---|---|---|
| SD | 7.5 | 124 |
| IOP | 33 | 197 |

0 late Critical PMs

(0.75% FLR)

**ER Projects**

**Target**

Improve Equipment Reliability

ERI = 70%  FLR = 5.5%

Maintenance Resources

(0.25% FLR)

Outage Duration/ Operator Time

Backlog Reduction

Outage Duration

# Darlington - Executive Summary

Darlington's goal is to be the best performing nuclear plant in the world. In 2012, our Peer Review confirmed that the station is on the right path. Darlington's objective for the 2013-2015 plan is to continue its "*Journey of Excellence*" while positioning the station for refurbishment and beyond.

Two key focus areas for continuing improvement are in equipment reliability and leadership development.

- Equipment reliability will lead to improved station performance.
- Leadership development will be implemented through improved leadership behaviours.

This plan will also ensure the station is prepared for the refurbishment outage through integration and alignment.

**Key Operating Assumptions**

- Unit 2 refurbishment will commence in October 2016.
- Minimal derates due to Heat Transport System (HTS) aging (Neutron Over Power (NOP) analysis accepted in 2013).
- No large scale fuel channel gap inspection program.
- Advance D1711 outage work in 2014 and 2015 to minimize 2017 outage duration.
- 12 year VBO cycle.

# Darlington - Major Focus Areas

Continue implementation of initiatives and improvement plans:

## SAFETY

- Improve fuel reliability
- Use a graduated risk management approach
- Continue to improve work protection performance
- Reduce tritium emissions
- Implement Fukushima programs (e.g. emergency response)
- Implement Conventional Safety improvements

## RELIABILITY

- Improve fuel handling material condition
- Utilize an integrated aging management approach for life cycle management
- Improve Water Treatment Plant
- Enhance chemistry performance
- Reduce online backlogs
- Decrease Zebra Mussel fouling and Microbiologically Induced Corrosion

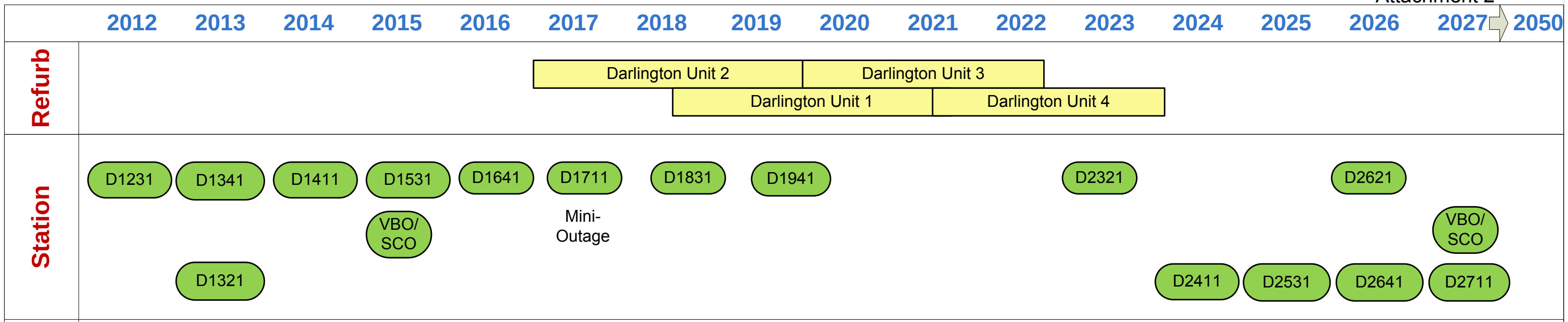
## HUMAN PERFORMANCE

- Enhance leadership development
- Improve licensed operator throughput
- Utilize effective change management and communication
- Improve employee engagement
- Reinforce accountability

## VALUE FOR MONEY

- Change frequency of VBO/SCO outage cycle to once every 12 years
- Align and integrate with Refurbishment Project
- Improve work order readiness
- Implement Capital Minor Modifications
- Increase productivity efficiencies

# Darlington - Vision



## Targets

**2015 Performance (VBO Impact)**

CF 86.3%
FLR 1.00%
CRE 73.8 rem/unit
NPI 96.1
83 day planned outage (D1531)

Top Performing Plant

**Post Refurbishment**

CF High Capability
FLR Industry Leading
CRE Continuous Improvement
NPI Industry Leading
TGC Low cost
40 day planned outages
Live 0 corrective/deficient backlogs

## Scope/Process

| | Campus Plan: | Project Portfolio: | Refurbishment: |
|---|---|---|---|
| Safety | Boiler House | Passive Auto-Catalytic Recombiners<br>Tritium Emissions Reduction Project<br>Restore ESW and Firewater Margins<br>RRS Logic Module Redesign<br>Fukushima Emergency Telecom Enhancement<br>Fukushima Emergency Mitigation Equipment | Emergency Power Generator 3<br>Containment Filter Venting System Mods<br>Shield Tank Over Pressurization<br>Powerhouse Steam Venting System Mods<br>Emergency Heat Sink |
| Infrastructure | Darlington Energy Complex<br>West Security Office Building<br>Water and Sewer Project<br>Electrical Power Distribution System<br>Warehouse Facilities<br>Road & Bridges<br>Maintenance Facility<br>OSB Refurbishment<br>Waste Storage Building<br>Waste Volume Reduction Building<br>Refurb Island Annex | Station Lighting Retrofit<br>Domestic Waterline Replacement<br>PA System Upgrade<br>Underground Services Replacement<br>Powerhouse Roof Replacement<br>Sally Port Physical Barrier Installation | In-Station infrastructure<br>Lay-Up/Islanding Mods (multiple mods) |
| Reliability | D2O Storage Facility<br>Water Treatment Plant Replacement | Fuel Handling Improvements<br>Major Pump-sets Vibration Monitoring System Upgrades<br>Shutdown System Computer Aging Management<br>SG Controls Replacement<br>DCC Replacement / Refurbishment / Upgrades<br>EPS Uninterruptible Power Supply Replacement<br>Class II UPS Replacement<br>Pressurizer Heaters & Controllers Replacement<br>EPG2 Gas Producer Engine Replacement<br>Zebra Mussel Mitigation Improvements<br>Boiler Blowdown Piping Refurbishment | Replace & Retube Feeder & Reactor Components<br>Replace PHT & Auxiliaries System<br>Refurb Moderator & Auxiliary System<br>Refurb Emergency Coolant Injection<br>Refurb End Shield Cooling System<br>Repair/Replace Shutdown System Computer<br>Closure Plug Replacement<br>Refurb Instrument Tubes<br>PHT LRV Modifications<br>PHT Pump Motor Replacement<br>Steam Turbine Electronic Controls Upgrade<br>Boiler Primary Side Clean |

# Darlington - Maintenance Resource Headcount On the Tools

| Year | Mechanical | Control | Civil | FIN | Total Headcount (Base Hours) |
|---|---|---|---|---|---|
| 2008 | 132 | 167 | 121 | 0 | 420 (611,520) |
| 2009 | 109 | 144 | 119 | 25 | 397 (578,032) |
| 2010 | 103 | 136 | 110 | 25 | 374 (544,544) |
| 2011 | 100 | 134 | 108 | 25 | 367 (534, 352) |
| 2012 | 93 | 136 | 99 | 29 | 357 (519,792) |
| 2013 | 94 | 121 | 89 | 32 | 336 (489,216) |
| 2014 | 93 | 117 | 88 | 32 | 330 (480,480) |
| 2015 | 93 | 117 | 88 | 32 | 330 (480,480) |

- Includes staff on the tools (Maintainers and FLMa's) from maintenance sections identified (based on approved Business Plan Numbers 2008 through 2013 plans)
- With declining resources, the following strategies will be implemented to meet work load demand:
    - Pre-authorization of work
    - Days based maintenance
    - Outsourcing

# Nuclear Waste Management - Executive Summary

Nuclear Waste Management Division’s (NWMD) goal is to achieve the highest standards in the safe management of nuclear waste.

NWMD’s scope of work is managing ongoing nuclear waste for Ontario’s Nuclear Generating Stations (Pickering, Darlington and Bruce Power). This plan will focus on the following:

- Pickering: Support life extension and prepare for shut down.
- Darlington: Prepare for Refurbishment and support the Vacuum Building Outage in 2015.
- Bruce Power: Provide waste management services and continue on-site tritiated heavy water transfers between Bruce A and B.

On-site facilities at the Western Site have expanded with the in-service of Used Fuel Storage Buildings 3 & 4, and Low Level Storage Buildings 13 & 14. In-ground Containers-18’s in-service in 2013 for intermediate level waste.

**Key Operating Assumptions**

- While reducing overall costs, maintain increased production targets of Dry Storage Containers (DSCs) at the Darlington and Pickering Waste Management Facilities with no additional staff increases.
- Darlington Retube Waste storage building in-service in 2016.
- L&ILW Deep Geologic Repository (DGR) delayed by 3 years to accommodate the Joint Review Panel process.
- One additional year of fuel storage will be required as a result of Pickering operating to 247k EFPH.
- Assess technical, financial, and operability of the Low and Intermediate Level Waste (L&ILW) incinerator and determine future operation or refurbishment.

# Nuclear Waste Support to Bruce Power

Bruce Power pays OPG annually for the life-cycle management of their nuclear waste which includes processing, storage, and disposal. The revenue stream is in effect while the Bruce units are in operation. OPG's commitment to store and dispose of the Bruce used fuel and waste will continue post operations.

The majority of the revenue relates to the management of their Used Fuel, with the balance relating to the management of their Low & Intermediate Level Waste.

NWMD provides the following support to Bruce Power on an annual basis:

- Receive, process, and store 130 DSC's per year ([redacted] staff dedicated to this work).
- Receive, sort, process, and store 2,800 $m^3$ per year of L&ILW.
- Transportation services of radioactive material.
- Conventional landfill management services.

# Nuclear Waste Management - Major Focus Areas

## SAFETY

- Strive for zero High Maximum Reasonable Potential for Harm Events
- Improve Fire Protection Program and Systems
- Maintain Wildlife Habitat Council Certification

## RELIABILITY

- Improve System Health Reports
- Develop Aging Management for Used Fuel and Low and Intermediate Level Waste Systems and Structures
- Implement Trench Remediation and Overpack Project
- Improve Work Management organization and process

## HUMAN PERFORMANCE

- Develop Systematic Approach to Training-compliant training and improve NWMD training programs and performance measures
- Enhance leadership behaviours and accountabilities

## VALUE FOR MONEY

- Execute a L&ILW processing strategy with a focus on volume reduction and reduction of the environmental footprint
- Process and store annual commitment of Dry Storage Containers
- Execute Used Fuel long term potential cost reduction initiatives
- Simplify governance

# Nuclear Operations - Staff Plan

| **MAJOR DIVISIONS** | **Year End Headcount** | | |
|---|---|---|---|
| **Regular Staff** | **2013** | **2014** | **2015** |
| Pickering | 1,851 | 1,786 | 1,764 |
| Pickering Workforce Development Program | 8 | 57 | 66 |
| Darlington | 1,198 | 1,154 | 1,140 |
| Darlington Workforce Development Program | 35 | 33 | 33 |
| Darlington Refurbishment Workforce Development Program | 33 | 41 | 21 |
| Nuclear Engineering | 962 | 921 | 882 |
| Engineering Workforce Development Program | 8 | 8 | 8 |
| Fleet Operations and Maintenance (excluding Workforce Development Program) | 149 | 139 | 136 |
| Maintenance Roving Outage Crew | 72 | 72 | 72 |
| Nuclear Waste Management | 203 | 202 | 200 |
| Nuclear Services (including RP Project Crew) | 236 | 222 | 213 |
| Security and Emergency Services | 566 | 556 | 544 |
| Office of Chief Nuclear Officer and Chief Nuclear Operating Officer | 4 | 4 | 4 |
| **Regular Staff Total** | **5,325** | **5,195** | **5,083** |

**Major Contributors to Staff Savings**

- Management of attrition and position vacancies, and mitigating impact through Business Transformation Initiatives, Fleet and Local Improvement Initiatives, productivity improvements and appropriate prioritization of work
- Consolidation and centralization (e.g., Pickering amalgamation, Business Transformation)
- Process improvements and streamlining
- Reduced management and increased span of control through centre-led organization
- Standardization of programs, processes and equipment
- Optimization of services and utilization of contractors (e.g., EPC design vendors)
- Automation of processes and report generation

# Nuclear Operations – Financial Plan

**3 Year Cost Plan ($ Millions)**

| Cost Category / Work Program | 2013 | 2014 | 2015 |
|---|---|---|---|
| **OM&A** | | | |
| Base | 1,063.3 | 1,079.6 | 1,081.3 |
| Outage | 235.5 | 208.6 | 260.1 |
| **Total OM&A** | **1,298.8** | **1,288.1** | **1,341.3** |
| | | | |
| **Capital** | | | |
| Minor Fixed Assets | 10.3 | 11.7 | 12.1 |
| **Total Capital** | **10.3** | **11.7** | **12.1** |
| | | | |
| **Provision Expenditures** | | | |
| Decommissioning P2/P3 Long Term | 8.2 | 8.4 | 8.6 |
| Low & Intermediate Level Waste | 38.1 | 33.5 | 33.5 |
| Used Fuel Storage | 69.3 | 69.2 | 68.9 |
| **Total Provision** | **115.5** | **111.1** | **111.0** |

**Note:** Overall organizational accountability for execution of OM&A and Capital Projects (including the Nuclear Portfolio) resides with the Nuclear Projects organization. To align with current Corporate Reporting, all Project costs are shown under Nuclear Projects.

| Fuel Costs ($ Millions) | 2013 | 2014 | 2015 |
|---|---|---|---|
| **Fuel** | | | |
| Uranium | 215.9 | 220.3 | 207.1 |
| Combustion Turbine Unit (CTU) | 4.0 | 4.1 | 4.2 |
| Used Fuel Storage and Disposal | 52.5 | 56.0 | 56.5 |
| **Total Fuel** | **272.4** | **280.3** | **267.8** |

# Nuclear Business Plan Risks

| Risk Description | Risk Treatment | Residual Risk |
|---|---|---|
| **Failure to Retain and Replace Leadership Talent** | | |
| OPG's constrained compensation structure, and the current Business Transformation strategy to lower staff levels through attrition, will inhibit retaining and attracting necessary resources in a competitive labour market. The Province has constrained compensation for public sector executives and planning to reform public sector pension plans. The business impacts have the potential to be significant. | Mitigation plans include: Regular review of internal candidates with focus on enhanced development of future leaders; enhanced coaching and support to managers for successor candidates; Emerging Talent program to identify and fast track high performance/high potential employees with longer career horizons to become leaders of future; and identify emergency successors for leadership roles to mitigate the risk of sudden departures. | Residual risk is the same as original risk level during the implementation of mitigation plans. The risk will reduce over time as the development and leadership skill enhancement occurs. |
| **Unexpected Fuel Channel Degradation at Darlington** | | |
| Fitness for service of pressure tubes cannot currently be demonstrated beyond 2013, due to reduced fracture toughness. Fitness for service of annulus spacers cannot be demonstrated beyond 2014. | Fuel Channel Life Management Project provided a new fracture toughness curve and timelines to modify heat-up and cool-down operations. A Long Term Spacer Management Plan (LTSMP) will be developed and executed. Regulatory concurrence will be secured on the plan and outcome. | The residual risk is the inability to depressurize to new low pressures during start-up and cool-down. The Regulator may not accept the disposition of reduced margins in a timely way. Insufficient confidence following inspections, tests and samples from the core, may lead to expansion of the inspection and spacer retrieval program or the results may show spacers are not fit for duty. |
| **Darlington Primary Heat Transport Pump Motor Failures Impacting Station Operations** | | |
| There are indications of winding deterioration in 8 of 16 motors. One degraded spare is available; additional spares will be available in 9-12 month timeframe. | Partial discharge monitoring is being installed (50% complete). Four new spare motors are being procured (Q3 2013). Targeted motors will be replaced and condition assessments will quantify the risk. | Current risk is that a single failure results in a 35 day forced outage. Dual failure would result in a 9 to 12 month forced outage. |
| **Parts Procurement Impacting Station Operations** | | |
| There is no proactive process for managing parts procurement. Issues include late identification of needed parts, the quality of vendor manufacturing, and strategies for stocking and re-ordering parts. OPG parts procurement is further challenged by aging plant components. Lack of a proactive obsolescence management process leads to reactionary behaviours (emergent and rush priorities). | Nuclear Supply Chain has several initiatives underway to address parts procurement and obsolescence issues. | Parts procurement and obsolescence issues impacting on lost production are expected to decline by year-end 2014. Some of the initiatives are in the early stages of implementation. As many of the underlying causes to these issues are organizational and behavioural, the implementation is considered difficult to manage. |
| **New Regulation to Lower Tritium Limit in Drinking and Ground Water** | | |
| Ontario Drinking Water Advisory Committee recommended to the Ontario Ministry of Environment (OMOE) a Drinking Water Standard of 20 Bq/L of tritium as an annual average, which is a fraction of current Ontario and Federal standards. | A strategy will be developed for implementation should the government propose to change the Drinking Water standard and/or Ground Water limit. | There is a residual risk that the tritium limit in drinking water may be decreased, causing OPG to be in non-compliance when there is a transient in tritium concentration. |

# Nuclear Business Plan Risks (Continued)

| Risk Description | Risk Treatment | Residual Risk |
|---|---|---|
| **Pickering  Fuel Handling Failures Impact Station Operations** | | |
| Fuel Handling systems are at the end of 30 year design life, and reliability is poor. | Component obsolescence and end of life challenges will be addressed through component replacements.  AP-913 will be implemented to identify issues and develop project scope.  Fuel Handling FLR will be monitored through the Plant Health process. | Not all Single Point Vulnerable components will be replaced. |
| **Vendor Quality Issues Impacting Equipment Reliability** | | |
| Nuclear generation lost due to vendor quality issues amounted to $74.5 million in 2010 (or 1.4 TWh) and $5.2 million in 2011 (or 0.1 TWh).  As of July 2012, nuclear generation lost, due to vendor quality issues, was $20 million (or 0.3 TWh). | In 2011,  OPG implemented a new management system for managing and monitoring supplier's quality performance including a process on tracking, controlling and dispositioning counterfeit, fraudulent, and/or sub-standard items (CFSI).<br>In 2012, continued to refine the management system implemented in 2011.  Supplier performance monitored using KPIs and metrics for generation loss, threats, and rework.<br>Completed a self assessment on 'near miss' or lower tier quality incidents that could have negatively impacted on generation.  Corrective action plan is in progress. | Target is 0.3 TWh by 2015.  Continued vendor quality/CFSI issues causing lost generation. |
| **Loss of Atomic Energy of Canada Limited (AECL) Capability and Knowledge** | | |
| Nuclear relies on AECL to support many maintenance and project activities.  Due to the Government of Canada's annouced restructuring of AECL, there continues to be substantial uncertainty around the future capabilities of AECL. | OPG reviewed its AECL contracts and is negotiating with AECL for a long term service agreement for intellectual property (IP) owned by AECL.  OPG is also negotiating with AECL for a separate IP agreement which clarifies OPG's rights to use the IP where past contracts were silent or unclear.  Where OPG has clear IP rights, OPG is exploring Engineering, Procurement, Construct contracts with other vendors. | Residual risk relates to those specialized services and tooling which AECL has uncontested, or potentially contested, IP rights and/or existing capabilities such that an option of selecting an alternative vendor is not possible for OPG now, nor would OPG be able to quickly contract with an alternative vendor following demise of AECL.<br>A subcomponent of residual risk is that some IP rights reside within AECL repository, so that future access could also be restricted. |
| **Darlington Emergency Power Generator Failures (EPG) Impacting Station Operations** | | |
| EPG2 high bearing vibrations and nozzle cracks reduce service life and carry risk of failure. | Project will optimize strategy for installation of 3rd EPG and refurbishment of EPG2.<br>Minimize thermo shock during testing and monitoring. | Failure of EPG2 followed by functional failure of EPG1 results in station outage and high cost to repair EPG2. |
| **Surplus Nuclear Inventory Value Exceeds Provision at Pickering End of Life** | | |
| The value of surplus nuclear inventory on hand at the time Pickering reaches end of life (EOL) exceeds the set aside provision.   An inadequate inventory obsolescence provision may eventually result in extraordinary charges to OPG’s reported income. | A cross functional team with Supply Chain, Nuclear Operations and Finance staff has been developing a Project Charter and detailed action plans, including a third party wall to wall physical count in 2013, of Nuclear inventory, to validate the accuracy of inventory. | There may be surplus inventory on hand at the time of Pickering's end of life that exceeds the end of life provision.  The financial impact could be between $50 and S100 million. This residual risk is to be re-assessed after risk treatment actions are completed. |

# Nuclear Projects - Executive Summary

Nuclear Projects will continue to manage and execute high value projects, in alignment with Nuclear Operations, while satisfying the need for increased decommissioning expertise and leveraging a range of industry best practices, operating experience and lessons learned to achieve project management excellence.

Nuclear Projects is also responsible for planning and obtaining the necessary approvals for additional nuclear generation capacity. 2013-2015 Business Plan highlights include:

- Completing the Detailed Planning of the Definition Phase of Darlington Refurbishment with a focus on maintaining availability of skilled technical, trades, and project management workers to successfully deliver projects with quality, on time and on budget.
- Continuing to support the Government decision process and execute a strategy that facilitates New Nuclear at Darlington, as an integral part of Ontario's future energy mix and in accordance with the Long-Term Energy Plan released by the Ministry of Energy.
- Implementing effective Labour Relations strategies while leveraging the Extended Service Master Services Agreement (MSA) to enable Projects and Modifications to effectively execute the increased project work program with a reduced staff level.
- Providing the nuclear generating stations with quality specialized inspection and maintenance services that are delivered in an effective manner and improve the efficiency of processes.
- Continuing to be accountable for planning and preparing for decommissioning requirements, including program and engineering oversight and design authority functions for OPG's Low and Intermediate Level Waste Deep Geological Repository and oversight of Nuclear Waste Management Organization's Adaptive Phased Management program for used fuel.

The 2013-2015 OPG Nuclear Projects Business Plan incorporates key elements of the Corporate Business Transformation initiative and commits to delivering projects on time and on budget to the highest quality standards while ensuring the safety of all personnel involved.

# Nuclear Projects - Planning Assumptions

**Nuclear Refurbishment**

- First unit refurbishment (Unit 2) – October 2016.
- Refurbishment duration – all 4 units – 88 months.
- Plan includes funding for Facilities and Infrastructure projects required to support refurbishment and ongoing station operations.

**Darlington New Nuclear Project**

- OM&A program addresses the continuation of the planning and preparation activities including:
  - The Service Agreement process to be completed by 2013 year-end.
  - Compliance with the License to Prepare Site.
  - Progressing the long lead environmental follow-up program items.

**Projects & Modifications**

- The Projects and Modifications work program will focus on Operational Project Portfolio execution, and Nuclear Waste and Darlington Refurbishment project work.
- Conduct of Maintenance initiative will reduce Contractor Management Office and field engineering staffing requirements in future outages.

**Inspection and Maintenance Services**

- Work scope is aligned with the Fuel Channel Life Management Project and station generation plans.
- The IMS work program does not support Nuclear Refurbishment other than pre-refurbishment inspections.

**Nuclear Decommissioning Organization**

- CNSC decommissioning requirements will not substantially change over the business planning period.
- Pickering shut down and safe storage plans will not be modified significantly from the current reference plan.
- The schedule for the Low and Intermediate Level Waste Deep Geological Repository (DGR) has been adjusted to accommodate an extended Joint Review Panel process.
- The schedule for NWMO’s Used Fuel Repository assumes an in-service date of 2035.

# Nuclear Projects - Issues and Focus Areas

**Projects and Modifications**

- Focus on reducing regular staff headcount while undertaking an increased project work program and maintaining safety, quality, cost and schedule.
- Implement an effective Labour Relations strategy and leveraging the Extended Services Master Service Agreement critical to ensure the success of executing the project work program with reduced staff levels.

**Inspection & Maintenance Services**

- Provide the nuclear generating stations with quality specialized inspection and maintenance services that are delivered in an effective manner.
- Improve the efficiency of processes, ensure the reliability of equipment and executing the program with skilled staff.

**NDO / NWMO Oversight**

- Decommissioning: Continue to work on the Preliminary Decommissioning Plans and associated cost estimates; plan for decommissioning of the Pickering site; improve the decommissioning planning process; and remain involved in rulemaking and regulations.
- Oversee the Regulatory Approval Phase of OPG’s Low and Intermediate Level Waste Deep Geological Repository until it receives the license for the Site Preparation and Construction.
- Provide oversight of OPG’s Adaptive Phased Management to ensure value for money and optimization of the long term management of used fuel.

**Nuclear Refurbishment**

- Develop effective and efficient project management, including: oversight of contractors, in an EPC contracting environment; contract management and monitoring capability and processes.
- Finalize scope and develop the Release Quality Estimate.
- Complete Refurbishment pre-requisites such as: design, fabrication and testing of Retube and Feeder Replacement tooling; and completion of Facilities and Infrastructure projects.
- Obtain regulatory approvals of Environmental Assessment, Integrated Safety Review and Integrated Improvement Plan.

**Nuclear New Build**

- Support the Government process for evaluation of the cost and schedule for two potential nuclear reactors at Darlington.
- Continue to execute a strategy that supports New Build as an integral part of Ontario’s future energy mix.
- Advancing key regulatory compliance and commitment activities that affect the scope and schedule for New Build.
- Maintaining an organization dedicated to planning and preparation activities.

# Alignment of Project Portfolio to Objectives and Risk Mitigation

## SAFETY

- Continue completion of CNSC Fukushima action items by Q4 2013, e.g.:
    - Demonstrating Severe Accident Management Guidelines (SAMG) effectiveness using table-top exercises and drills, and assessing survivability of equipment essential to SAMG execution
    - Evaluating potential for hydrogen generation and need for hydrogen mitigation in the Irradiated Fuel Bay areas
- Complete Probabilistic Risk Assessment Upgrade Project over 2013-2014
- Comply with Regulatory requirements and commitments (e.g., Environmental Qualification, Fire Protection, Security, Fire Safety Assessment Upgrade, Pickering Fish Barrier)
- Strong Nuclear Safety Culture; Zero Lost Time Accidents

## RELIABILITY

- Support the Pickering Equipment Reliability Plan (e.g., through major projects such as P1-4 Turbine Governor Upgrade and P5-8 Fuel Handling Reliability Project)
- Undertake specific Reliability Projects (e.g., replacement of Darlington Digital Control Computers and Darlington Shutdown System Monitor Components)
- Meet station demand for increased minor modifications budgets
- Integrate Life Cycle Management Plans and Component Condition Assessments into portfolio development and prioritization
- Ensure committed Waste Provision Projects remain on schedule and budget (e.g., waste facility upgrades and modifications)

## HUMAN PERFORMANCE

- Simplify project management governance through a high level framework
- Simplify business processes and procurement (e.g., matrix Supply Chain staff and ES MSA contract)
- Enhance project management oversight by ensuring alignment with strategic direction and improving quality and delivery standards
- Improve project management competency by implementing focused workshops and hiring experienced project managers
- Develop emerging project leaders and target training in Nuclear Engineering on high need areas (e.g., Design Engineering)

## VALUE FOR MONEY

- Complete the Fuel Channel Life Management Project (e.g., Probabilistic Leak Before Break methodology, Transition Region regulatory issue, Darlington 10-year Spacer Plan)
- Extended Services MSA agreement – leverage EPC strategy, with more accountability on vendors
- Business Transformation Initiatives in Nuclear Engineering impacting projects
- Strategic sourcing for Technical Contractors

# Nuclear Refurbishment - Executive Summary

Darlington Refurbishment is completing the Detailed Planning of the Definition Phase.

- Plan will be updated consistent with the planned release of funds and reflects improved cost estimates.
- Overall project cost remains within previous estimate; major change is related to annual cash flows.
- Key deliverables in the business planning period include:
  - Post submission activities related to the Environmental Assessment (EA) and Integrated Safety Review (ISR)
  - Submission of the Integrated Improvement Plan (IIP)
  - Completion of refurbishment pre-requisite work
  - Negotiation and award of remaining major contracts, e.g. Turbine Generator, Fuel Handling, and Steam Generator Primary Side Clean
  - Preparation for refurbishment execution including completion of scoping, engineering, planning, and Release Quality Estimate (RQE) by October 2015
  - Completion of the construction of facilities and infrastructure required to support Darlington Refurbishment Project
  - Completion of Retube and Feeder Replacement (R&FR) tooling and mockup

# Nuclear Refurbishment - Major Focus Areas

- Developing effective and efficient project management, including oversight of contractors, in an EPC contracting environment.
- Developing contract management and monitoring capability and processes.
- Scope finalization and development of Release Quality Estimate:
  - Implementation of contracting strategies
  - Finalization of cost estimates and schedules
  - Completion of all engineering deliverables
- Design, fabrication, and testing of R&FR tooling to determine project durations for re-tube and feeder replacement activities.
- Completion of Facilities & Infrastructure projects needed for Darlington Refurbishment.
- Completion of refurbishment pre-requisite work including work tied to approved scope, as well as Station Improvement Opportunity projects and minimize interferences with VBO.
- Obtaining regulatory approvals of Environmental Assessment, Integrated Safety Review and Integrated Improvement Plan.
- Continue discussions with Power Workers Union and Building Trades Union.

# Nuclear New Build - Executive Summary

- Long-Term Energy Plan released by the Ministry of Energy commits to the procurement of additional units at Darlington.
- All decisions to move forward with the two potential nuclear reactors will be made by the Government of Ontario.
- OPG continues to support the Government decision process.
- Service Agreements were signed with each of Westinghouse and SNC-Lavalin/Candu Energy to prepare detailed construction plans, schedules and cost estimates.
- Continue to execute a strategy that supports New Nuclear at Darlington as an integral part of Ontario's future energy mix.
- Project OM&A reflects the resources for successful compliance with the License to Prepare Site (LTPS) requirements, as well as supporting the Government decision process.

**Key Operating Assumptions**

- OM&A program for continuation of the planning and preparation activities assumes:
  - Analysis of the Service Agreement deliverables as provided by Westinghouse and SNC Lavalin/Candu Energy prior will be completed by 2013 year end.
  - On-going compliance and monitoring of the Environmental Assessment and License to Prepare site commitments.
  - The Government decision to proceed with new nuclear is expected in early 2014.
  - Progressing the long lead environmental activities will ensure the Project can proceed without delays.

# Nuclear Projects - Staff Plan

| MAJOR DIVISIONS<br>Regular Staff | Year End Headcount<br>2013 | <br>2014 | <br>2015 |
|---|---|---|---|
| Projects & Modifications | 330 | 326 | 322 |
| Inspection & Maintenance Services | 373 | 363 | 363 |
| Nuclear Decommissioning | 7 | 7 | 7 |
| NWMO Oversight | 1 | 3 | 4 |
| EVP-Nuclear Projects | 2 | 2 | 2 |
| **Subtotal - Operations Support** | **713** | **701** | **698** |
| Nuclear Refurbishment | 247 | 266 | 276 |
| Nuclear New Build | 23 * | 21 * | 21 * |
| **Regular Staff Total** | **983** | **988** | **995** |

**Major Contributors to Staff Savings**

- IMS savings from consolidation of positions and programming changes (e.g. optimize outage coordination).
- Projects & Modifications savings from: extended services from Master Services Agreement strategy; Purchased Services Agreement overflow - maintenance quality model; and simplification of governance and processes and right-sizing training.
- Major Project staff numbers are indicative and evolving, subject to change from more detailed planning. Refurbishment reflects timing adjustments. New Build currently reflects the Base Case of not proceeding.

* Note: For resource planning purposes, Nuclear New Build staff levels are shown for planning and preparation for development of project. Staff levels will be reassessed if the project is approved.

# Nuclear Projects - OM&A Cost Plan

**3 Year Cost Plan ($ Millions)**

| Cost Category / Work Program | 2013 | 2014 | 2015 |
|---|---|---|---|
| **Base and Outage** | | | |
| Base | 51.0 | 49.7 | 52.4 |
| Outage | 100.3 | 75.5 | 90.5 |
| **Total Base and Outage OM&A** | **151.3** | **125.1** | **142.8** |
| **Project** | | | |
| Nuclear Project Portfolio | 84.3 | 101.1 | 105.8 |
| Fuel Channel Life Management | 14.7 | 6.8 | 0.6 |
| Pickering Continued Operations | 6.0 | 6.0 | 0.0 |
| **Operations Support Projects** | **104.9** | **113.9** | **106.4** |
| Darlington Refurbishment | 18.2 | 19.6 | 18.2 |
| Nuclear New Build | 38.6 * | 10.3 * | 9.5 * |
| **Major Projects** | **56.7** | **30.0** | **27.7** |
| **Total Project OM&A** | **161.6** | **143.8** | **134.1** |
| **Total OM&A** | **312.9** | **268.9** | **277.0** |

* Note: Nuclear New Build costs are for planning and preparation activities and will be reassessed if the project is approved.

# Nuclear Projects - Capital and Provision Plans

**3 Year Cost Plan ($ Millions)**

| Cost Category / Work Program | 2013 | 2014 | 2015 |
|---|---|---|---|
| **Capital** | | | |
| Projects - Nuclear Portfolio (including Capital Spares) | 150.3 | 175.0 | 122.2 |
| Minor Fixed Assets | 9.6 | 9.6 | 9.6 |
| **Operations Support Capital** | **160.0** | **184.6** | **131.8** |
| Nuclear Refurbishment | 529.8 | 837.4 | 631.8 |
| Nuclear New Build * | - | - | - |
| **Total Capital** | **689.8** | **1,022.0** | **763.6** |
| | | | |
| **Provision Expenditures** | | | |
| Decommissioning - Preparation for Safe Storage P6 Units | 1.8 | 1.6 | 3.0 |
| IMS - Used Fuel Storage | 0.6 | 0.6 | 0.6 |
| Provision Projects | 40.1 | 40.1 | 40.0 |
| | | | |
| Nuclear Decommissioning | 1.1 | 1.0 | 1.1 |
| NWMO DGR (Deep Geologic Repository) | 19.5 | 19.9 | 74.6 |
| NWMO APM (Adaptive Phased Management) | 52.0 | 70.2 | 106.4 |
| NWMO L&ILW DGR Oversight & APM | 6.5 | 10.2 | 10.4 |
| **Subtotal - Provision-NDO/NWMO** | **79.0** | **101.2** | **192.5** |
| | | | |
| NWMO - Refurbishment Retube Waste Containers | 1.6 | 17.6 | 17.5 |
| **Total Provision** | **123.2** | **161.1** | **253.6** |

* Note: Capital costs for Nuclear New Build will be defined upon project approval.

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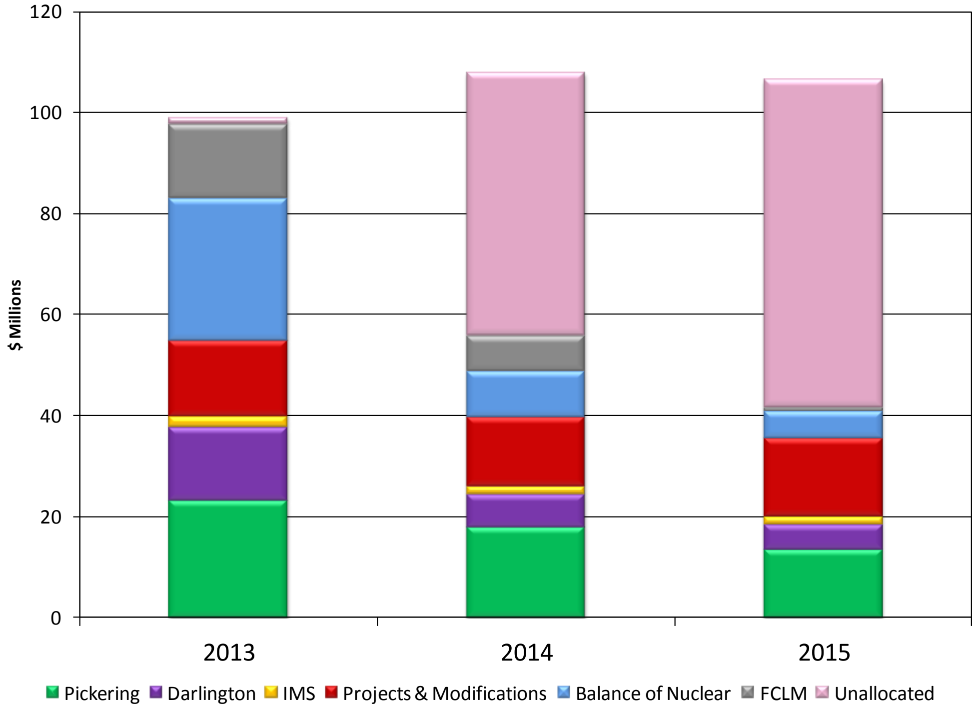
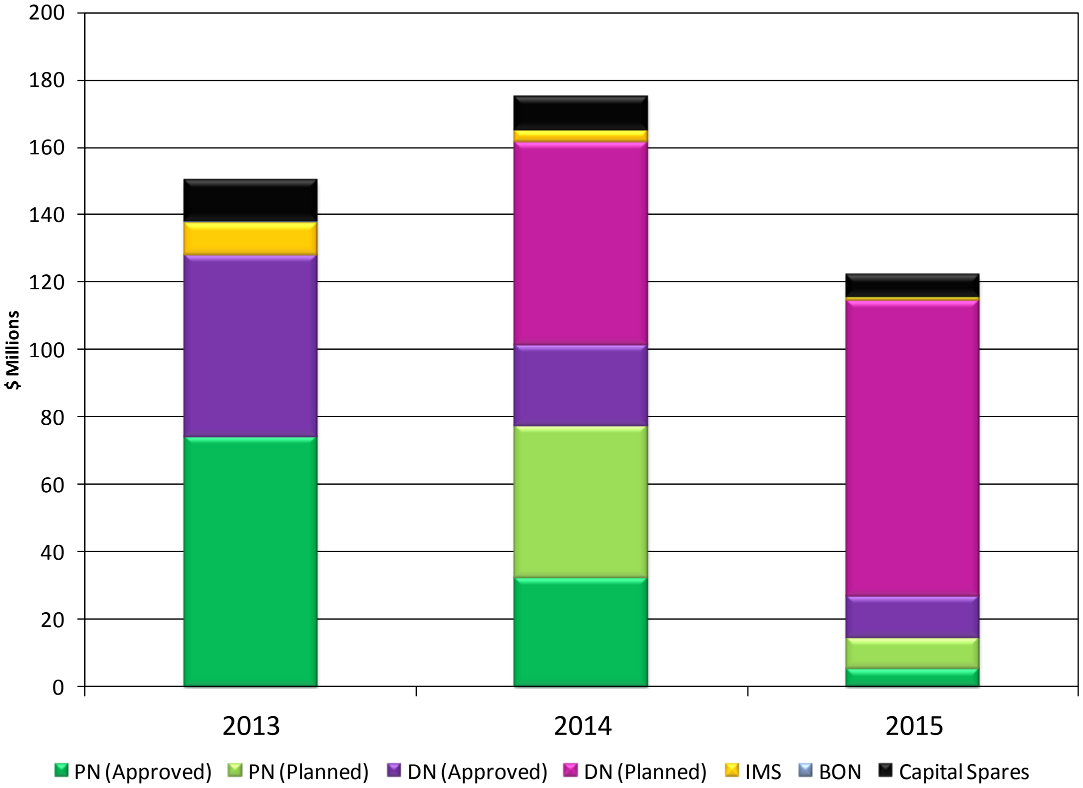
Attachment 2

# 2013-2015 OM&A Project Portfolio



- The OM&A Portfolio takes into account:
    - Spending on minor modifications to ensure safe and reliable operation to scheduled end-of-life at Pickering
    - Ongoing Fukushima related projects for program management and procedure development
    - End of the Fuel Channel Life Management project

# 2013-2015 Capital Project Portfolio



- The Capital Portfolio takes into account:
  - Increased investment in Darlington to sustain safe and reliable operation
  - Appropriate investment in Pickering to maintain safe and reliable operation as it approaches its scheduled end-of-life
  - Investment in Fukushima related projects
  - Acquisition of capital spares to replace life expired components

# Appendix A

## Nuclear Support Program Details

# Nuclear Support

## Nuclear Engineering

- Centre-led, Nuclear Engineering management structure and accountability.
- Business Transformation initiatives to enable improvements.
- Initiative to improve Design Quality.
- Engineering Knowledge Retention and ‘Emerging Leaders’ Program.
- Delivered on Fuel Channel Life Management (FCLM), Probabilistic Risk Assessment, Power Operated Valves and Pickering Fish Net Projects.
- Darlington Refurbishment Support (specialized engineering).
- Ongoing Fukushima Response: Implementation.
- Pickering 3K3 reliability initiative on track.
- Engineer/Procure/Construct (EPC) model moving into execution phase.

## Fukushima Response

- Completed 48 of 101 Fukushima Action Items (FAIs) and working toward completion of 27 more by year end. (Note that CNSC closure of actions is still pending on the majority of completed FAIs.) (2012)
- Implemented Emergency Mitigation Equipment (Phase I) to provide cooling and monitoring capability in the event of an extended loss of AC power. (2012)
- Continuing analysis under Probabilistic Risk Assessment Project (PRA) and Severe Accident Management Guidelines (SAMG) Project, such as Multi Unit events and structural integrity of IFBs. (2012)
- Installation of Passive Autocatalytic Recombiners (PARs) on D3 (complete) and P1 & P7 (planned). (2012)
- SAMG effectiveness demonstrated using table top exercises and drills. Assessment of the survivability of equipment and instruments essential in SAMGs ( FAI 1.8). (2013)
- New start: option evaluation for Pickering Beyond Design Basis (BDB) Containment Venting Improvements. (2013)
- Progression of next phases of improvements for SAMG and EME. (2013)
- Continued PARs installation on remaining units . (2013-2014)
- Industry agreement and determination of Regional Emergency Response Centre. (2013)

# Nuclear Support (Continued)

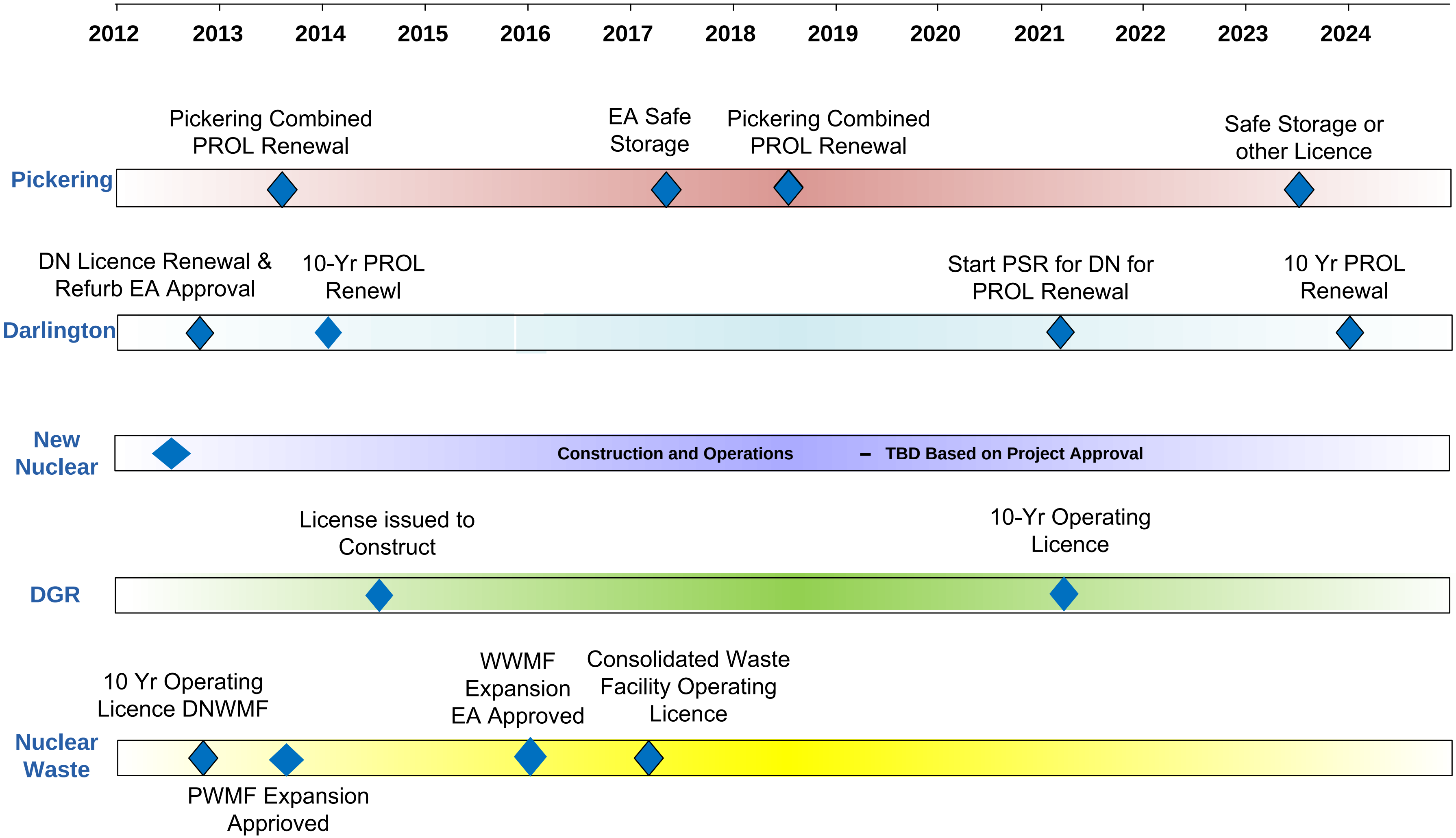
## Nuclear Services

Nuclear Services' vision is to be a reliable and responsive resource and deliver value to Nuclear Operations and Projects by:

- Providing effective and efficient Radiation Protection Services, Regulatory Affairs, Strategic Planning and Benchmarking, Environmental Assessments and Stakeholder Relations centre led functions to Nuclear Operations and Nuclear Projects.
- Focusing attention on and driving fleet wide initiatives for continuous improvement as identified through: operational benchmarking; highlighting our performance to industry performance, standards and expectations to identify gaps for improvement.
- Setting high quality achievable performance standards and monitoring business performance against these standards.
- Maintaining regulatory relationships and influencing regulatory agencies to facilitate the needs of the Nuclear businesses, and obtaining all CNSC regulatory approvals.
- Safely delivering Radiation Protection services to Nuclear Operations.
- On behalf of the CNO and EVP-Nuclear Projects, support development of strategic plans for the Nuclear business.

# Nuclear Operations Support

## OPG Major Licensing Activities



# Nuclear Support (Continued)

## Operations and Maintenance Support

**Enabling Improved Fleet Performance through:**

- Leadership
- Direction Setting and Performance Monitoring – Corporate Functional Area Managers
- Process Improvement
- Collaboration
- Partnership

**Key Focus Areas:**

- Improved Work Protection: Model permits in use at sites for targeted systems; Integrate work protection into technical procedures to simplify processes; Quality focus on PC1 application and prepare and check of permits; and Implementation of standard permits.
- Operations Excellence: Supervisory selection and development; Coordinating enhancements to technical and behavioural training across sites; and Operations-led reduction in operations challenges and backlog, and improved plant reliability.
- Reducing Corrective Maintenance Backlog: Develop, implement and monitor Maintenance backlog reduction plans at the sites (2013 - NFI - 04).
- CAP improvement: Continued execution and monitoring of plan at sites focusing on improved behaviours and results.
- Business Transformation transition: Executing the plan.
- Governance Simplification and Reduction: Review freeze and process simplification.

# Nuclear Support (Continued)

## Security and Emergency Services

- Based on May 3, 2012 Business Transformation, transitioning 9 departments into a centre led Enterprise for Security and Emergency Services OPG-wide.
  - **SES Programs** – Enterprise focus on Governance, Investigations, Intelligence, Risk, and Clearance
  - **Pickering Security** – Site security services including access, detection and protection systems, defensive strategies
  - **Darlington Security** – Same as above with a focus on additional Refurb activities
  - **Emergency Management (EM) and Fire Protection** – Enterprise EM Strategy, Nuclear Emergency Preparedness, Fire Protection Program, Training, and Emergency Response Team
  - **Specialized Training** – Security training to meet all Regulatory requirements including armed qualifications
- Capitalize on synergies and realize cost savings with efficient and effective centre led functions.
- Human Performance Improvement; integrated drills (EM / Security / Fire), leadership courage, field presence.
- Commitment of continued high standard of operational support to stations in all disciplines.
- Continued focus on value for money through: adaptive resourcing; and overtime reduction in fire and security.

# Nuclear Support (Continued)

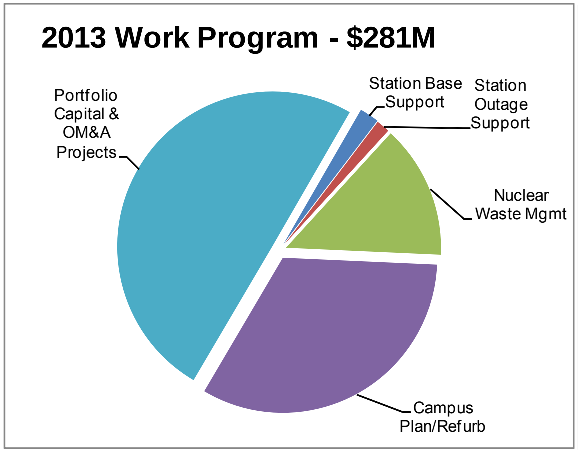
## Projects & Modifications

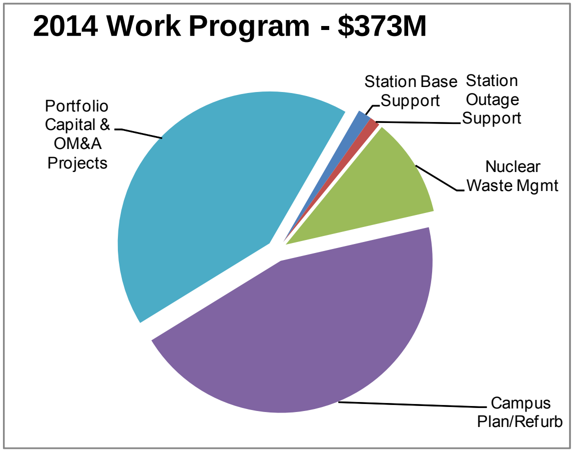
Projects & Modifications will focus on reducing regular staff headcount while undertaking an increased project work program and maintaining safety, quality, cost and schedule.

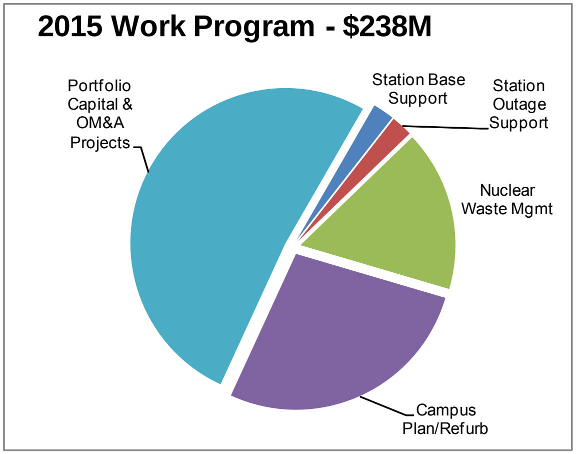
Implementation of an effective Labour Relations strategy and leveraging the Extended Services Master Service Agreement is critical to ensure the success of executing the project work program with reduced staff levels.

From the 2012 value of $263M, the project work program is expected to grow in 2013 and 2014 with the following cost mix.

### Projected Work Program







# Nuclear Support (Continued)

## Inspection & Maintenance Services

Inspection & Maintenance Services will provide the nuclear generating stations with quality specialized inspection and maintenance services that are delivered in an effective manner.

The 2013-2015 business plan is focused on improving the efficiency of processes, ensuring the reliability of equipment and executing the program with skilled staff.

These objectives will be achieved by:

- Implementing strategies to improve critical path performance
- Benchmarking vendors to look for improvement opportunities
- Improving equipment reliability through tooling upgrades and improved maintenance practices
- Completing major projects and developing new tooling solutions on time (e.g., Universal Delivery Machine delivered GAP)
- Effectively implementing the Human Performance plan
- Developing a long term Strategic Plan – charting the future of IMS over the next 10 years

# Nuclear Support (Continued)

## Nuclear Decommissioning & NWMO Oversight

- The Nuclear Decommissioning Organization (NDO) is responsible for planning and preparing for decommissioning of all OPG owned Nuclear facilities.
- Consistent with this long term program, NDO also provides:
  - Program and Engineering oversight and Design Authority functions for OPG’s Low and Intermediate Level Waste Deep Geologic Repository (L&ILW DGR).
  - Oversight of NWMO’s Adaptive Phased Management (APM) Program for Used Fuel.

**Major Focus Areas**

- **Decommissioning**
  - Continue to improve the Preliminary Decommissioning Plans (PDPs) and associated cost estimates.
  - Continue to plan for decommissioning of the Pickering site.
  - Continue to improve decommissioning planning process.
  - Continue involvement in rulemaking and regulations.
- **OPG’s L&ILW DGR**
  - Continue to oversee the Regulatory Approval (RA) Phase until OPG receives the license for Site Preparation and Construction.
  - Continue oversight of the EPCM contract for Design and Construction .
- **NWMO’s APM**
  - Continue OPG’s oversight of APM to ensure value for money and optimization of the long term management of used fuel.

# Appendix B

# Darlington - Refurbishment Integration

# Refurbishment Integration

**Processes in Place**

- Darlington Work Management embedded in Refurb organization
- Darlington Integration Manager in role – Campus plan, Refurb pre-requisites
- Refurb work scope integration presented monthly at Value for Money Journey of Excellence and Senior Work Management meetings
- Refurbishment organization working to MA-13 and MA-22 process and milestones. Includes flags identifying mandatory outage scope
- Memo of Understanding and Service Level Agreements in development
- Integrated Work Flow Analysis document completed
- Campus Plan updates monthly at Site Management Board
- Darlington members of the following Nuclear Refurbishment forums:
  - Bi-monthly NEC meetings
  - Refurbishment Project Meeting
  - Technical Screening Committee
  - Funding Committee
  - Scope Review Board
    - Items proposed for descoping must go through station Long Range Plans

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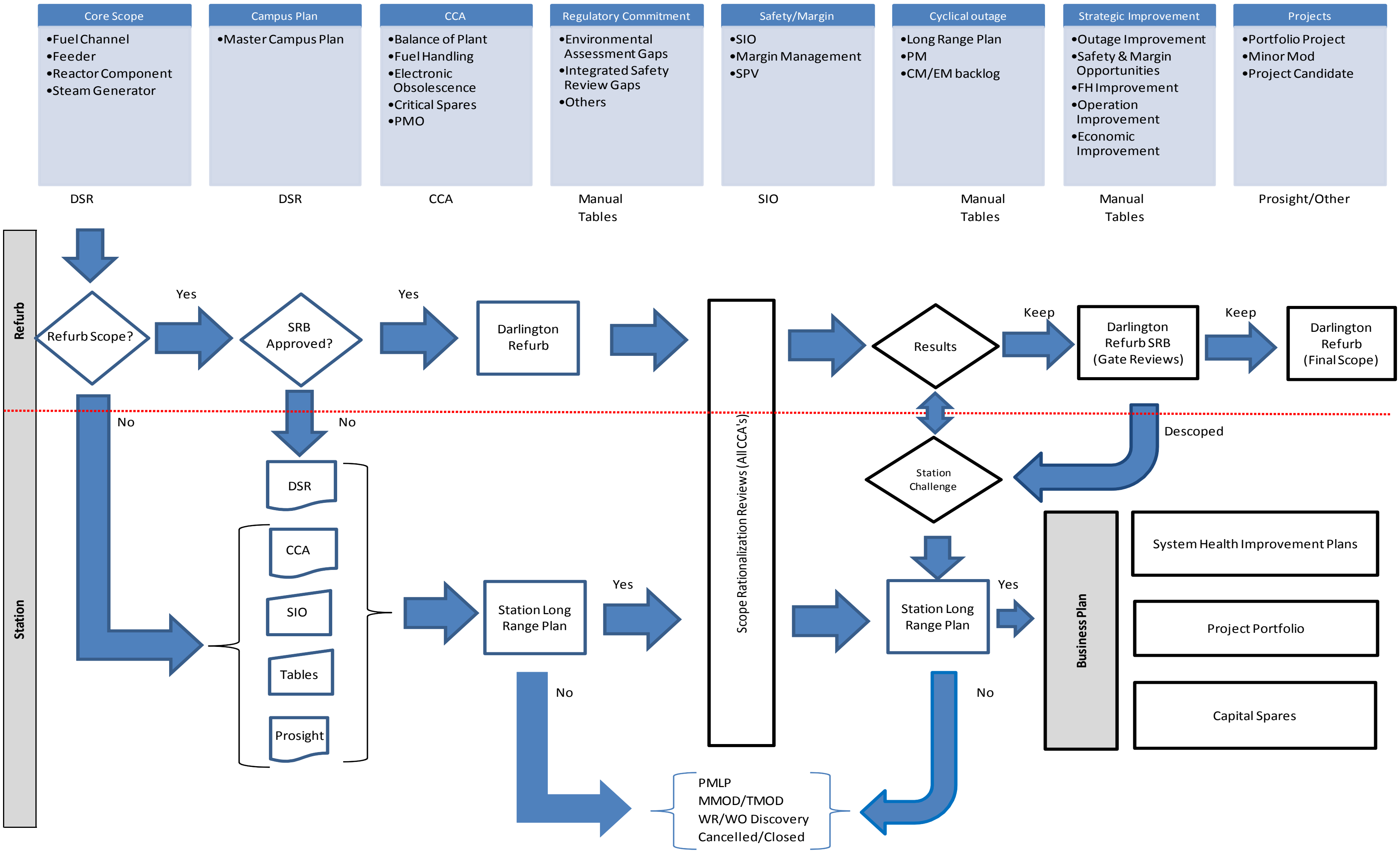
Attachment 2

# Refurbishment/Campus Plan/Project Work

| | | Work Orders | | | | | | M$ (estimated) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Refurbuburbishment Pre-Requisites** | **2012** | **2013** | **2014** | **2015** | **2016** | **Unscheduled** | **2012** | **2013** | **2014** | **2015** | **2016** |
| Work | On-line Work Orders | 23 | 13 | 11 | 0 | 0 | 280 | 0.5 | 0.3 | 3.0 | 2.0 | 0.8 |
| | Outage Work Orders | 12 | 152 | 25 | 9 | 6 | 25 | 0.2 | 3.0 | 0.7 | 0.4 | 0.1 |
| | Dry Storage Containers | 60 | 60 | 60 | 60 | 60 | | 7.2 | 7.3 | 7.4 | 7.7 | 7.8 |
| Projects / Campus Plan | Water Treatment Plant | | → | → | → | | | 4.5 | 17.9 | 26.6 | 2.6 | |
| | Electrical Power Distribution System | | → | → | → | | | 2.0 | 5.3 | 5.5 | 3.3 | 1.2 |
| | Water/Sewer Replacement | → | → | → | | | | 11.0 | 15.1 | 7.5 | 0.6 | |
| | Maintenance Building | → | → | | | | | 15.7 | 11.8 | 2.0 | | |
| | Darlington Energy Complex | → | → | ⇢ | | | | 58.1 | 20.4 | 0.7 | | |
| | PHT Pump Motor Replacement | | | → | → | → | | | | 8.0 | 8.0 | 8.0 |
| | Station Lighting | | → | → | → | → | | | 1.5 | 2.0 | 2.0 | 2.0 |
| | ZM Mitigation Improvements | | → | → | → | | | | 0.1 | 0.5 | 2.0 | 2.0 |
| | OSB Refurbishment | | | → | → | | | 0.7 | 6.8 | 28.4 | 2.2 | 0.4 |
| | D2O Storage Facility | | → | → | → | | | 9.1 | 40.4 | 40.9 | 14.7 | |
| | West Security Office Building | | → | → | → | | | 2.1 | 7.0 | 45.0 | 6.0 | 3.0 |
| | Boiler House | | → | → | → | | | 2.4 | 14.8 | 23.8 | 3.0 | 0.2 |
| | Powerhouse Roof Replacement | | | → | → | → | | | 2.7 | 2.7 | 2.7 | 2.7 |
| | Pressurizer Heaters/Controllers Replacement | → | → | → | → | → | | 1.5 | 3.2 | 1.6 | 1.6 | 1.0 |
| | Passive Auto-Catalytic Recombiners | → | → | → | → | → | | 0.6 | 2.1 | 0.8 | 0.2 | |
| | IFB Hx Replacement | | → | → | → | | | | 3.5 | 1.5 | 0.3 | |
| | FH Improvements (multiple projects) | → | → | → | → | → | | 4.4 | 8.9 | 10.0 | 10.0 | 10.0 |
| | ALW Refurbishment | | → | → | → | → | | | 0.3 | 0.4 | 0.4 | 0.1 |
| | In-Station infrastructure | | | → | → | | | | 3.0 | 6.0 | 6.0 | 3.0 |
| | Emergency Heat Sink | | → | → | → | | | | 2.0 | 7.0 | 7.0 | 4.0 |
| | Shield Tank Over Pressurization | | → | → | → | → | | 0.1 | 1.5 | 2.4 | 3.5 | 2.5 |
| | ESW Header Connection | | → | → | → | | | | 0.4 | 0.7 | 1.0 | 0.7 |
| | Moderator Connection | | → | → | → | | | | 0.3 | 0.5 | 0.8 | 0.6 |
| | EPG3 | | | → | → | → | | 0.5 | 7.5 | 12.0 | 17.5 | 12.5 |
| | Refurb Island Annex | | | → | → | | | 0.8 | 2.0 | 17.0 | 6.0 | 1.3 |
| | Fukushima - Emergency Storage Building | | → | | | | | 0.2 | 0.5 | 0.1 | | |
| | Containment Filter Venting System Mods | | | → | → | | | | 6.0 | 7.5 | 9.0 | |
| | Lay-Up/Islanding Mods (multiple mods) | | | → | → | | | | 3.4 | 5.7 | 5.7 | 13.7 |
| | Powerhouse Steam Venting System Mods | | → | → | → | | | | 2.0 | 4.0 | 3.5 | 0.5 |
| | Waste Volume Reduction Building | | → | → | → | → | | | 12.5 | 17.5 | 17.5 | 2.5 |
| | Waste Storage Building | | | → | → | → | | | 0.7 | 3.6 | 6.6 | 3.6 |
| | | | | | | | | **121.6** | **214.2** | **303.0** | **153.6** | **84.2** |

ONTARIOPOWER GENERATION

# Refurbishment Work Integration Process



**Core Scope**
- Fuel Channel
- Feeder
- Reactor Component
- Steam Generator

DSR

**Campus Plan**
- Master Campus Plan

DSR

**CCA**
- Balance of Plant
- Fuel Handling
- Electronic Obsolescence
- Critical Spares
- PMO

CCA

**Regulatory Commitment**
- Environmental Assessment Gaps
- Integrated Safety Review Gaps
- Others

Manual Tables

**Safety/Margin**
- SIO
- Margin Management
- SPV

SIO

**Cyclical outage**
- Long Range Plan
- PM
- CM/EM backlog

Manual Tables

**Strategic Improvement**
- Outage Improvement
- Safety & Margin Opportunities
- FH Improvement
- Operation Improvement
- Economic Improvement

Manual Tables

**Projects**
- Portfolio Project
- Minor Mod
- Project Candidate

Prosight/Other

**Refurb**

Refurb Scope?

Yes

SRB Approved?

Yes

Darlington Refurb

Scope Rationalization Reviews (All CCA's)

Results

Keep

Darlington Refurb SRB (Gate Reviews)

Keep

Darlington Refurb (Final Scope)

**Station**

No

No

DSR

CCA

SIO

Tables

Prosight

Station Long Range Plan

Yes

No

Descoped

Station Challenge

Station Long Range Plan

Yes

No

PMLP
MMOD/TMOD
WR/WO Discovery
Cancelled/Closed

**Business Plan**

System Health Improvement Plans

Project Portfolio

Capital Spares

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Ex. F2-3-3
Attachment 1 Tab 2

ONTARIOPOWER GENERATION

BUSINESS CASE SUMMARY

## Pickering B Steam Generator Locking Tab Replacement 13 - 40641

## Full Release Business Case Summary NK30-BCS-33115-00007-R000

### 1/ RECOMMENDATION:

We recommend a full release of $20.5M (including contingency) to design, install, and commission new locking devices in all 12 Steam Generators (SGs) in Unit 7 during the 2008 outage and Unit 8 during the 2010 outage.

The business objective of this project is to remove the current requirement to shut down Unit 7 and Unit 8 after 6.3 Effective Full Power Years (EFPYs) because of the threat of fatigue failure of the cold leg locking tabs, by developing and installing a new design that will:

- ☐ Allow Units 7 and 8 to run until End of Life (EOL) without concerns of locking tab failure
- ☐ Reduce the overall project cost and dose uptake by ~$4.3M and 40% respectively (compared to Units 5 and 6)
- ☐ Align with the Pickering B 85/5 initiative by allowing installation within a 40 day outage schedule
- ☐ Allow inspection/maintenance to be conducted with minimal interference with the new design
- ☐ Allow for the removal and/or replacement of components of the new design with relative ease, if required

If a cold leg locking tab were to fail, it is speculated that it would cause significant damage to the Heat Transport System. More importantly, a broken cold leg locking tab could block Primary Heat Transport (PHT) water flow through feeder pipes and orifices. Lack of flow can cause overheating of fuel and result in fuel failure. In the worst case scenario, a broken cold leg locking tab could cause Pressure Tube failure leading to a Loss of Coolant Accident (LOCA). However, repairs to Units 7 and 8 can be postponed until March 2011 and October 2010 respectively since a Fitness for Service Evaluation of cracked hot leg locking tabs concluded that cold leg locking tabs will not fail prior to 6.3 Effective Full Power Years (EFPYs) and failure of hot leg locking tabs is not an operability issue. This analysis is based on a safety factor of 2. (see Glossary)

Locking tab design problems were first experienced when broken pieces of locking tabs and sealing skins were found on the hot leg (inlet) side of the Unit 5 SGs during the P551 outage. Similar problems were later found in Unit 6. The root causes were determined to be insufficient design analysis for the locking tabs and inadequate installation of the sealing skins. Repairs to both locking tabs and sealing skins were conducted on Units 5 and 6 because of the imminent threat posed by the sealing skin installation. Due to greater rigor applied during the installation of sealing skins in Units 7 and 8, there is no need to replace them prior to End of Life (EOL). Additionally, there is no need to replace the locking tabs on Units 5 and 6 as they are expected to operate without problems to EOL.

We have considerable experience in locking tab design and installation; however, a [redacted] contingency has been included to address the risk associated with designing, qualifying and installing a new design or defaulting to the Unit 5/6 design in the remote chance that the new design is ineffective and/or cost prohibitive.

| $M (incl contingency) | Funding | LTD 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|
| Currently Released | None | - | - | - | - | - | - | - | - |
| Requested Now | Full | - | - | 0.6 | 9.4 | 0.5 | 9.7 | 0.3 | 20.5 |
| Future Funding Req'd | | | | | | | | | - |
| Total Project Costs | | - | - | 0.6 | 9.4 | 0.5 | 9.7 | 0.3 | 20.5 |
| Other Costs | | | | | | | | | - |
| Committed Cost | | | | 12.9 | (6.4) | (1.0) | (5.5) | | - |
| Grand Total Release | | - | - | 13.5 | 3.0 | (0.5) | 4.2 | 0.3 | 20.5 |

| Investment Type | Class | (IEV) Impact on Ec Value | IRR | Discounted Payback |
|---|---|---|---|---|
| Sustaining | OM&A | 645.0 | 238.5% | 3.5 |

Submitted By:

Feb 20/07

P. Tremblay
Senior Vice President Pickering B

Date:

Finance Approval:

D. Power
Director Investment & Business Planning

March 8/07
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

for

J. Hankinson
President & CEO

Date:

## 2/ BACKGROUND & ISSUES

### Adverse Condition

The Steam Generator Divider Plate sealing skin modification was performed on Units 1, 4, 5-8 starting with Unit 4 in 2001 and finishing with Unit 7 in 2004. The primary purpose of this modification was to address Divider Plate bolt degradation as well as the steady increase in Reactor Inlet Header Temperature (RIHT) which was forcing some units to run derated. All modifications were completed successfully as measured by the decrease in RIHT for each unit. When the first unit (U5) SG inspections were conducted during the P551 (Spring of 2005) Outage following installation of the sealing skin/locking tab modification, it was discovered that numerous pieces of locking tabs and divider plate sealing skin had broken off in the hot leg (inlet) side of the steam generators (refer to SCR P-2005-03243) due to high cycle fatigue cracking. Further inspections revealed that all 10 affected steam generators experienced locking tab failures, and 4 of 10 steam generators experienced divider plate skin failures. The root causes of this event were deemed to be insufficient design analysis for the new locking tabs and inadequate sealing skin contact with the Primary Head seat bar.

### Repair Scope for Unit 7 and 8

During the original divider plate installations in P481 (Unit 8, 2004) and P471 (Unit 7, 2004), more rigor was applied for installation of sealing skins and design improvements to the skins were made. As a result there is a lower probability of sealing skin failure in these steam generators. This has been proven through subsequent inspections carried out during P681 (Spring of 2006) and P671 (Fall of 2006), as only 1 SG out of the 12 SGs inspected was found with minor, but acceptable skin failures. However, there were no changes made to the design of the locking tabs, so similar numbers of broken hot leg locking tabs have been seen in Unit 8 and 7. To date no broken locking tabs have been reported in cold leg (outlet) side of the any the inspected SGs.

A Fitness for Service Evaluation of cracked locking tabs for PNGS A and PNGS B (P-REP-33115-00001 R01) concluded that cold leg locking tabs will not fail prior to 6.3 EFPYs and failure of hot leg locking tabs is not an operability issue. This assessment allows the delay of the locking tab replacement until the 2010 Outages while development of an improved fastener design is underway to reduce the installation duration, dose and cost. Although it is acceptable from a Fitness for Service perspective to defer the locking tab replacement to 2010, performing this modification for all 24 SGs in 2010 is not aligned with the 85/5 initiatives. Thus, locking tab replacement will be completed in Unit 7 SGs in 2008 and Unit 8 SGs in 2010.

### Similar Previous Replacement Campaigns

As mentioned, hot leg locking tab failures were first found in Unit 5. Similar failures were found in Unit 6 Steam Generators during P561 Outage. Upon this discovery, all of the sealing skins, locking tabs, and associated components in all Unit 5 steam generators (except for two steam generators which were previously modified in 1999 with a different Divider Plate design) and in all Unit 6 steam generators were replaced. These repair campaigns were costly, lengthy, and dose intensive as shown below:

Project #13-40932, Unit 5 – approximately $11M, 2 months, 33 Rem (10 steam generators)
Project #13-40632, Unit 6 – approximately $12M, 2 months, 65 Rem (12 steam generators)

This BCS covers the funding required for the development, qualification and testing of the new design along with field installation. This project will focus on locking tab replacement (currently installed sealing skins will be retained), and minimizing cost, time, and dose during execution. There are no plans to replace the locking tabs in Units 5 and 6 as they are evaluated to be operational to EOL.

## 3/ ALTERNATIVES AND ECONOMIC ANALYSIS

Based on the fact that cold leg locking tabs will not fail prior to 6.3 Effective Full Power Years (EFPYs), we have several options for scheduling the installation work. The following analysis examines the impact of various options based on 40 days outages and planned Water Lancing for Units 7 and 8.

| $ Millions | Status Quo | Alt 1 (Recommended) New Design in 2008 / 2010 Full Cost | Alt 1 (Recommended) New Design in 2008 / 2010 Incremental Cost | Alt 2* Old Design in 2008 / 2010 | Alt 3 New Design In 2008 | Alt 4 New Design In 2010 | Alt 5 New Design In 2008 / 2010 |
|---|---|---|---|---|---|---|---|
| **SG's / Outages / Critical Path** | | | | | | | |
| P871 | 0 | 12 | 12 | 6 | 12 | | 6 |
| P881 | 0 | | | 6 | 12 | | 6 |
| P1071 | 0 | | | 6 | | 12 | 6 |
| P1081 | 0 | 12 | 12 | 6 | | 12 | 6 |
| Waterlancing in Outage | N/A | 2008 (U8)<br>2010 (U7) | 2008 (U8)<br>2010 (U7) | 2010 (U8)<br>2010 (U7) | 2010 (U8)<br>2010 (U7) | 2010 (U8)<br>2010 (U7) | 2010 (U8)<br>2010 (U7) |
| Variance to Critical Path (1 outage) | N/A | -2-2 | -2-2 | +7+7+13+13 | -2-2 | +11+11 | -2-2+4+4 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Financials** | | | | | | | |
| Loss of Revenue | (1,532.2) | 0.0 | 0.0 | (22.5) | 0.0 | (12.0) | (4.4) |
| Project Cost | 0.0 | (20.5) | (20.5) | (25.9) | (20.2) | (20.2) | (20.5) |
| NPV (after tax) | (656.9) | (11.9) | (11.9) | (26.8) | (12.0) | (16.8) | (13.7) |
| **Financial Benefit (vs Status Quo)** | **N/A** | **645.0** | **645.0** | **630.1** | **644.9** | **640.1** | **643.2** |
| IRR% | N/A | 251.3 | 251.3 | 1.8 | 190.5 | 440.6 | 2.4 |
| Discounted Payback (Yrs) | N/A | 3.5 | 3.5 | 4.1 | 3.7 | 3.4 | 3.6 |
| **Ranking of Financial Benefits** | **6** | **1** | **1** | **4** | **2** | **5** | **3** |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Business Objectives** | | | | | | | |
| Fits Current Generation Plan | No | No | No | No | No | No | Yes |
| Allows operation beyond 6.3 EFPYs | No | Yes | Yes | Yes | Yes | Yes | Yes |
| Allows operation to EOL | No | Yes | Yes | Yes | Yes | Yes | Yes |
| Aligns with 85/5 initiative | No | Yes | Yes | No | Yes | No | No |
| 40% dose reduction | No | Yes | Yes | No | Yes | Yes | Yes |
| Benefit of new design | No | Yes | Yes | No | Yes | Yes | Yes |

*See Alternative 1 description.

**Status Quo - Not Recommended**

Status Quo is **not** the recommended option. This alternative is unacceptable because we would have to shut down both units with revenue losses accruing to approximately $1.5 Billion from the end of 6.3 EFPYs to EOL.

**Alternative 1 - Install 12 "New Design" Tabs in Unit 7 in 2008, 12 in Unit 8 in 2010 - Recommended**

We recommend this alternative because it satisfies the Business Objectives and provides the greatest financial benefit (when measured against the Status Quo). This alternative minimizes the risk of an outage extension by voiding concurrent Water Lancing and Locking Tab repair in the same outage. The recommendation is to vance Unit 8 Water Lancing by 2 years to 2008, install all Unit 7 Locking Tabs in 2008 and all Unit 8 Locking Tabs in 2010. This proposal has been accepted by the Site Management Board (SMB) and is being incorporated into the Generation Plan. Moving Unit 8 Water Lancing to 2008 is also supported by EMD due to the poor condition of Unit 8 SGs in terms of sludge build up.

**Alternative 2 - Install Unit 5 and 6 Design Locking Tabs in Units 7 & 8- Not Recommended**

We do **not** recommend this alternative because it doesn't satisfy the Business Objectives and provides the least financial benefit. This alternative is the contingency alternative should the new design not meet expectations.

**Alternative 3 – Install 12 "New Design" Locking Tabs in Units 7 & 8 in 2008 - Not Recommended**

Although this alternative meets the Business Objectives, we do not recommend it because there are increased schedule risks in completing both units in 2008. Moreover, the financial benefit is marginally less than the Recommended alternative.

**Alternative 4 – Install 12 "New Design" Locking Tabs in Units 7 and 8 in 2010 - Not Recommended**

We do **not** recommend this alternative because it doesn't align with the 85/5 initiative and provides only the 4th best financial benefit because of the outage extension. Moreover, leaving all Locking Tab installation until 2010 does not provide sufficient time to recover from unknown problems, without unfavourable financial impact.

**Alternative 5 – Install "New Design" in 6 SGs per U7 & U8 in 2008, remainder in 2010 - Not Recommended**

This is the current Generation Plan. We do not recommend this alternative because it has higher risk of extending the Outages than Recommended Alternative and provides only the 3rd best financial benefit.

## 4/ THE PROPOSAL

We propose a full release (as opposed to a developmental) at this time because:

- There is little or no risk that this project will be cancelled and the investment subsequently lost
- Major contracts need to be awarded by October 2007 in preparation for the Unit 7 Fall Outage in 2008
- Conceptual funding allowed us to determined the most technically viable and cost effective design from a number of locking tab replacement options
- An extensive risk profile with mitigating actions has been developed to reduce the overall risk to low
- We have considerable experience in locking tab design and installation; however, a [redacted] contingency has been included to address the risk associated with designing, qualifying and installing a new design or defaulting to the Unit 5/6 design in the remote chance that the new design is ineffective and/or cost prohibitive.

A Full Release will be used to:

- Complete the Design 100%
- Perform the Preliminary and Detailed Engineering
- Award a labour contract (for both units)
- Perform all pre-installation activities for Unit 7 (i.e. workplan preparation, work permits, space allocation, etc.)
- Install, commission, and AFS the modification for Unit 7 (P871)
- Revise Design Engineering documents as required (i.e. Design ECs, drawings, etc.) for Unit 8
- Complete pre-installation activities for Unit 8
- Install, Commission, and AFS the modification for Unit 8 (P1081)
- Close-out the Project

Refer to Appendix C for a list of the project milestones.

## 5/ QUALITATIVE FACTORS

None other than outlined in the Business Objectives.

## 6/ RISKS

| Description of Risk | Description of Consequence | Risk Before Mitigation | Mitigating Activity | Risk After Mitigation |
|---|---|---|---|---|
| **Cost** | | | | |
| Underestimation of cost. | Cost over run.<br>A futher release of funds will be required | **Medium** | Regular review of project expenditures. [redacted] contingency available. | **Low** |
| **Scope** | | | | |
| Results of Qualification Program could cause scope increase. | Change in scope resulting in changes in cost and schedule. | **Medium** | If scope growth too large, design installed in Units 5 and 6 is ready and available to be installed in Units 7 and 8. [redacted] contingency available. | **Low** |
| As-found conditions of SGs could invalidate analysis and/or uncover unexpected conditions. | Increase in scope of modification (i.e. skin replacement) resulting in cost and schedule overrun. | **Medium** | Inspections have been conducted on 6 SGs each of Unit 7 and 8 in 2006 and have no unexpected findings. Similar conditions are expected on the remaining SGs. | **Low** |
| Damage to SG internals during site execution. | Unplanned repair required. | **High** | SG internals will be protected during installation to preclude damage. Qualification testing as well as mock-up training will provide the basis for risk mitigation during execution. | **Low** |
| **Schedule** | | | | |
| Delay in obtaining required materials for qualification testing. | Schedule overrun. | **Medium** | Materials required for qualification testing have been identified. Some materials have already been obtained, and the remainder will be ordered promptly. | **Low** |
| Delay in completion of Design packages. | Schedule overrun. | **Medium** | Additional design resources will be obtained in order to meet deadlines. There is sufficient float in the project schedule to accommodate minor delays with no impact to start of installation | **Low** |

| | | | | |
|---|---|---|---|---|
| Extensive amount of welding rework during execution. | Increase in Outage critical path. | **High** | Qualification testing will be conducted to ensure limited access welds can be completed to meet acceptance criteria. | **Low** |
| **Resources** | | | | |
| Design Engineering resources re-allocated to higher priority projects. | Delay in Design deliverables | **Medium** | Design support has been committed to this project. | **Low** |
| Lack of qualifiedTrades to perform qualification testing due to conflict with P751 Outae. | Delay in qualification testing potentially leading to a delay in Design deliverables. | **Medium** | Trades will be acquired as soon as the qualification plan has been agreed upon. | **Low** |
| **Technical** | | | | |
| Locking Tab replacement option does not satisfy all contructability objectives | Constructability issues may impact design | **High** | Qualification testing will be done to ensure constructability issues are addressed and eliminated through completion of design. | **Low** |
| | | **Low** | | **Low** |
| **Regulatory** | | | | |
| Regulator may not approve the re-start submissions of Unit 7 and 8. | Unable to restart Unit 7 and 8. | **Medium** | Re-start submissions have been approved for Units 5 and 6 for similar modifications. | **Low** |
| **Environmental** | | | | |
| N/A | | | | |
| **Health & Safety** | | | | |
| Potential for safety related events during qualification and site execution due to several conventional and radiological | Injuries to personnel involved in qualification testing and installation. | **Medium** | Pre-job briefings will be conducted prior to commencement of qualification testing and during installation. Boiler bowls will be surveyed and cleaned if required, and lead | **Low** |

| | | | | |
|---|---|---|---|---|
| hazards. | | | shielding will be installed prior to personnel entries. All personnel involved will be required to wear appropriate PPE. Review Lessons Learned from previous campaigns | |
| **Investment** | | | | |
| The current requirement to shut down Unit 7 and Unit 8 after 6.3 (EFPYs) is not adequately addressed<br>The overall project cost and dose uptake targets are not achieved<br>The installation is not aligned with the 85/5 principles.<br>The new design inteferes with inspection / maintenance activities<br>Future Locking Tab problems prevent the operation of the Units to EOL<br>The new design does not allow for easy removal and or replacement of components | higher cost<br>higher dose uptake<br>extended schedule<br>outage extension | **Medium** | Locking Tab replacement option will be designed with a substantial amount of rigour.<br>Qualification Program will be conducted to ensure that the new locking device can meet these project objectives.and ensure that the Locking Tab replacement option is robust and will not become Foreign Material.<br>Results of qualification testing will be used to alter the design of the new locking device as required. | **Low** |
| | new project required to repair units<br>possible forced outage<br>higher costs | **Medium** | The Unit 5/6 design is available if this design proves to be too costly or not effective<br>[redacted] contingency is included | |
| Premature failure of cold leg locking tabs currently installed. | Advancement in preparation and installation of the new design<br>or<br>Repair of Units 7 and 8 with old design (installed in Units 5 and 6).<br>Both of these repairs would significantly impact schedule and costs. | **Low** | Analysis has been completed for the current design with a safety factor of 2 and locking tabs are not expected to fail prior to 6.3 EFPYs.<br>Contingency Divider Plate sealing skin sets (12 in total) of the current design are on site and available to be used for an emergent repair campaign.<br>[redacted] contingency is available and would provide sufficient funding in the remote chance that the Unit 5/6 design is required | **Low** |

## 7/ POST IMPLEMENTATION REVIEW PLAN

| Type of PIR: | Targeted Final AFS Date: | Targeted PIR Approval Date: | PIR Responsibility (Sponsor Title) |
|---|---|---|---|
| Simplified | Jan 2011 | Feb 2015 | Components & Equipment |

**Comments:**

| | Measurable Parameter | Current Baseline | Targeted Result | How will it be measured? | Who will measure it? (person / group) |
|---|---|---|---|---|---|
| 1. | Durability of Steam Generator divider plate fastener locking device | Unit 7 and 8 Boilers were found with several broken locking tabs | Divider plate locking device to remain intact until end of SG life. | Perform as-found inspections during the first and second planned outages subsequent to installation of the locking devices. Each steam generator must be inspected to confirm the Divider plate assembly is intact. | Major Components Section, Components and Equipment Department |
| 2. | | | | | |
| 3. | | | | | |
| 4. | | | | | |
| 5. | | | | | |

## Appendix "A" Glossary (acronyms, codes, technical terms)

- AFS: Available for Service
- CNE: Chief Nuclear Engineer
- CNSC: Canadian Nuclear Safety Commission
- EC: Engineering Change
- EFPY: Effective Full Power Year
- EOL: End of Life
- HTS: Heat Transport System
- NPV: Net Present Value
- RIHT: Reactor Inlet Header Temperature
- PNGS: Pickering Nuclear Generating Station
- PROL: Power Reactor Operating License
- SG: Steam Generator
- SMB: Site Management Board
- TOE: Technical Operability Evaluation
- Safety Factor of 2: In analyzing the operational life of the locking tabs, the largest crack size was used to account for the worst condition. This crack size was then multiplied by a safety factor of 2 in the model to predict the tab life.

## Appendix "B" Project Funding History

| $ 000's | | | Releases (incl contingency) Cumulative Values | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Release Type | Month | Year | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | Later | Total |
| Full | Nov | 2006 | | 13,326 | 3,148 | 0 | 3,990 | 61 | | | 20,525 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | |
| LTD Spent | Nov | 2,006 | 0 | | | | | | | | 0 |

**Comments:**

There have been no releases for this project to date as currently, conceptual funding is being used to perform preliminary work. A Full Release will be used to complete 100% design, installation, commissioning and AFS of the modification for Units 7 and 8 as well as the project close out. This approach will enable funding for early tender and award of installation contract.

## Appendix "C" Financial Model – Assumptions

### Project Cost Assumptions:

For the majority of engineering and design work, overtime has been assumed to be 10%. For field personnel, overtime has been assumed to be 25%. Installation estimate is based on Unit 5 and 6 experiences with assumed installation benefits for new design.

It is assumed that the Locking Tab replacement modification will be conducted over 2 outages as follows:

- Unit 7 during Fall 2008
- Unit 8 during Spring 2010

### Financial Assumptions:

The rate of inflation estimated at 2% is consistent with Corporate guidelines.

### Project / Station End of Life Assumptions:

Based on a memo to D. Power from J.P. Froats, "Pickering Units 5, 6, 7, and 8 End of Service Life Predictions", May 10, 2006, we have assumed that End of Life for Units 7 and 8 will be 1st quarter 2014 and 1st quarter 2016 respectively.

### Energy Price / Production Assumptions

The price of energy is estimated based on Corporate System Economic Values. Production from each Pickering B unit is assumed to be 516 MW at a capacity factor of 85%.

### Operating Cost Assumptions

N/A

### Other Assumptions:

The cold leg locking tabs are expected to fail after 6.3 EFPYs which is assumed to be:

- **Unit 7:** September 2011
- **Unit 8:** October 2010

Repairs to Units 7 and 8 can be postponed until September 2011 and October 2010 respectively because a Fitness for Service Evaluation of cracked hot leg locking tabs concluded that cold leg locking tabs will not fail prior to 6.3 Effective Full Power Years (EFPYs) and failure of hot leg locking tabs is not an operability issue. This analysis is based on a safety factor of 2.

## Pickering B Steam Generator Locking Tab Replacement 13 - 40641

## Full Release Business Case Summary NK30-BCS-33115-00007-R000

**Attachment "A"** **Project Cost Summary**

| $000's OM&A | LTD Prior Yr 2005 | This Release 2007 | This Release 2008 | This Release 2009 | This Release 2010 | This Release 2011 | | Later | Total |
|---|---|---|---|---|---|---|---|---|---|
| Project Management (OPG) | - | 241 | 223 | 280 | 318 | 163 | | | 1,225 |
| Engineering & Drafting (OPG) | - | 118 | 40 | 10 | 37 | 25 | | | 229 |
| Material | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Installation – PWU, BTU | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Contract - Design | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Contract - Installation | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Contract - Other | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Installation - IMS | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Interest (Capital Project Only) | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Project Costs (excl contingency)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| General Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Specific Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Project Costs (incl contingency)** | - | 626 | 9,448 | 526 | 9,664 | 261 | - | - | 20,525 |
| 2007-2011 Business Plan | | 700 | 6,300 | 1,000 | 6,000 | - | | | 14,000 |
| **Variance to Business Plan** | - | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Committed Cost | | 12,700 | (6,300) | (1,000) | (5,400) | | | | - |
| Inventory Write Off Required | | | | | | | | | - |
| Spare Parts / Inventory | | | | | | | | | - |
| **Total Release (excl contingency)** | - | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Total Release (incl contingency)** | - | 13,326 | 3,148 | (474) | 4,264 | 261 | - | - | 20,525 |
| **Ongoing OM&A (non-project)** | | | | | | | | | - |
| **Removal Costs (incl in above)** | | | | | | | | | - |

**Basis of Estimate**

| | | | | | |
|---|---|---|---|---|---|
| Design Complete | 100% | | Quality of Estimate | Budget + 30% to - 15% | |
| 3rd Party Estimate | N/A | OPEX used | Yes | Lessons Learned | Yes |
| Reviewed by Sponsor | N/A | Budgetary Quote(s) | No | Phase 1 Actual Used | N/A |
| Similar Projects | Yes | Contracts in place | No | Competitive Bid | N/A |

**Variance to Business Plan**

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Jan 2007.

Reviewed By:
Jan 26/07
P. Asgaripour
Project Manager
Date:

Approved By:
Jerry Keto 26 Jan 07
J. Keto
Eng & Mods Manager (Strat V)
Date:

## Pickering B Steam Generator Locking Tab Replacement 13 - 40641

## Full Release Business Case Summary NK30-BCS-33115-00007-R000

**Attachment "B"** **Project Variance Analysis**

| OM&A | Total Project | | Variance | Comments |
|---|---|---|---|---|
| | Units 5 and 6 | Units 7 & 8 | | |
| Project Management (OPG) | 824 | 1,225 | 401 | Additional cost due to longer project duration - 4 years instead of 2 years for Units 5 and 6. |
| Engineering & Drafting (OPG) | 529 | 229 | (301) | Replacement of fastener only. No design for sealing skins is required. |
| Material | [redacted] | [redacted] | [redacted] | [redacted] |
| Installation – OPG Support | [redacted] | [redacted] | [redacted] | [redacted] |
| Contract - Design | [redacted] | [redacted] | [redacted] | [redacted] |
| Contract - Installation | [redacted] | [redacted] | [redacted] | [redacted] |
| Kinetrics | [redacted] | [redacted] | [redacted] | [redacted] |
| Contract - Other | [redacted] | [redacted] | [redacted] | [redacted] |
| Installation - IMS | [redacted] | [redacted] | [redacted] | [redacted] |
| **Sub Total** | [redacted] | [redacted] | [redacted] | [redacted] |
| Foreign Material Unit 6 | [redacted] | [redacted] | [redacted] | [redacted] |
| BARC/Open/ Close | [redacted] | [redacted] | [redacted] | [redacted] |
| Unit 7 & 8 contingency | [redacted] | [redacted] | [redacted] | [redacted] |
| **Project Costs (excl contingency)** | [redacted] | [redacted] | [redacted] | [redacted] |
| General Contingency | [redacted] | [redacted] | [redacted] | [redacted] |
| Specific Contingency | [redacted] | [redacted] | [redacted] | [redacted] |
| **Project Costs ( incl contingency)** | **26,234** | **20,525** | **(5,709)** | |

**Comments:**

This project was identified in March 2006. Currently, conceptual funding is being used to start the Design work and prepare the Full Release BCS.

## Attachment "C" Key Milestones

| Completion Date | | | Description |
|---|---|---|---|
| Day | Mth | Yr | |
| 28 | Feb | 2007 | FR1: Full Release BCS Approved |
| 15 | Mar | 2007 | IDR: Design Requirements Approved and Issued |
| 13 | Oct | 2007 | FD1: Final Design Complete (Unit 7)<br>DCP: Design Permanent Mods Documents Issued |
| 01 | Nov | 2007 | MCA: Major Contracts Awarded (2 Units) |
| 20 | Sep | 2008 | SOI: Start of Installation (Unit 7) |
| 15 | Dec | 2008 | AFS: Available for Service Meeting (Unit 7) |
| 01 | Feb | 2009 | FD2: Final Design Complete (Unit 8)<br>DCP: Design Permanent Mods Documents Issued |
| 15 | Feb | 2010 | SOI: Start of Installation (Unit 8) |
| 15 | May | 2010 | AFS: Available for Service Meeting (Unit 8) |
| 15 | Feb | 2011 | PCS: Close-out Starts |
| 31 | Aug | 2011 | PCM: Plan Complete Milestone |
| | | | |
| | | | |

A Project Execution Plan (PEP) will be approved by May 2007

**Comments:**
All outage milestones will comply with N-PROC-MA-0013 **Revision 5B** (Planned Outage Management).

## Pickering A Steam Generator Locking Tab Replacement 13 - 49248

## Developmental Release Business Case Summary NA44-BCS-33115-00001-R000

### 1/ RECOMMENDATION:

We recommend a release of $1.2M (including contingency) to complete Preliminary Design of the preferred Steam Generator Locking Tab replacement option, develop a Full Release BCS, and generate a contract strategy for the Pickering A (Units 1 and 4) Locking Tab Replacement project by March 2008.

The business objective of this project is to avoid a significant forced outage due to a locking tab failure on the cold leg of the Heat Transport System. A Fitness for Service evaluation has indicated that the cold leg locking tabs have a minimum lifespan of 6.3 EFPYs. If a cold leg locking tab were to fail, it is speculated that it would cause significant damage to the Heat Transport System, potentially including some components of the reactor core (i.e. fuel bundles). A forced outage would then be required to repair the damage at a projected cost of $100M and duration of 90 days. More importantly, a locking tab failure could potentially affect OPG's standing with the CNSC and our Power Reactor Operating License (PROL). Beyond 6.3 EFPYs in service, justification for continued operation would be required for Units 1 and 4.

The deliverables of this project are:

- Complete a mini-field campaign to remove and re-install the SG Clamping Dogs in support of inspection by IMS during the P711 Outage
- Develop a new locking tab replacement option which will minimize/eliminate interference with routine maintenance activities as well as meet or exceed SG life expectancy
- Develop a new locking tab replacement option which will minimize project cost, schedule, and dose uptake
- Replace the locking tabs currently installed in Unit 1 and 4 steam generators (SG) with a new design prior to the calculated 6.3 year expected lifespan of the locking tabs (2010 and 2011)

Currently, preliminary work has been conducted to acquaint the project team with the project objectives and current field conditions. In addition, a number of locking tab replacement options are being reviewed to determine the most technically viable and cost effective.

As this project is related to Pickering A, there are no issues/opportunities with respect to the ongoing life extension assessment.

| $000's (incl contingency) | Funding | LTD 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|
| Currently Released | None | - |  |  | - | - | - | - | - |
| Requested Now | Developmental | - | 850 | 385 |  |  |  |  | 1,235 |
| Future Funding Req'd | Full | - | - |  | 520 | 7,675 | 7,905 | 400 | 16,500 |
| Total Project Costs |  | - | 850 | 385 | 520 | 7,675 | 7,905 | 400 | 17,735 |
| Other Costs |  |  |  |  |  |  |  |  | - |
| Ongoing Costs |  |  |  |  |  |  |  |  | - |
| Grand Total |  | - | 850 | 385 | 520 | 7,675 | 7,905 | 400 | 17,735 |

| Investment Type | Class | (IEV) Impact on Ec Value | IRR | Discounted Payback |
|---|---|---|---|---|
| Sustaining | OM&A | $146M | 75.2% | 5.9 |

Submitted By:

25 June 2007
M. Arnone
Director Projects & Modifications
Date

Finance Approval:

June 25, 2007
Date
Director [illegible] Management

Line Approval (Per OAR Element 1.1 Project in Budget):

June 27 2007
M. Reid
Director Station Engineering Pickering A
Date:

## 2/ BACKGROUND & ISSUES

**Adverse Condition**

The Steam Generator Divider Plate sealing skin modification was performed on Units 1, 4, 5-8 starting with Unit 4 in 2001 and finishing with Unit 7 in 2004. The primary purposes of this modification were to address Divider Plate bolt degradation as well as the steady increase in Reactor Inlet Header Temperature (RIHT) which was forcing several units to run derated. All the modifications were completed successfully as measured by the decrease in RIHT for each unit. The steam generator inspections conducted in Unit 5 during the P551 (Spring of 2005) Outage were the first to be done for the PNGS B units following installation of the sealing skin/locking tab modification. These inspections revealed that numerous pieces of locking tabs and divider plate sealing skin had broken off in the hot leg (inlet) side of the steam generators (refer to SCR P-2005-03243) due to high cycle fatigue cracking. Further inspections revealed that all 10 affected steam generators experienced locking tab failures, and 4 of 10 steam generators experienced divider plate skin failures. The root causes of this event were deemed to be insufficient design analysis for the new locking tabs and inadequate installation of the sealing skins to ensure proper seal. Subsequent steam generator inspections in Units 6 and 8 uncovered more broken locking tabs and sealing skins. It is expected that Unit 7 steam generators will exhibit the same adverse condition. There have been no locking tab failures observed in the cold leg (outlet) side of any steam generator inspected. [Note that Pickering A Units 1 and 4 have had no locking tab or skin failures to date but are considered vulnerable to similar failures found in Pickering B SGs.]

**Required Repair**

The sealing skin modification installed in the PNGS A units was similar to that of PNGS B, but not identical. Due to the Unit 5 event, PNGS A was obligated to review locking tab design installed in Units 1 and 4 in order to allow for continued operation of the units (refer to SCR P-2005-03370). An Engineering Assessment (NA44-33110) of the locking tabs installed in the PNGS A SGs was performed. In addition, steam generator inspections were conducted and showed that there had been no locking tab failures in the SGs. These two activities allowed for both PNGS A units to run for a period of 1.8 EFPYs since the sealing skin modification. The rationale for continued operation was due to the determination that hot leg tab failures can be tolerated from a reactor safety point of view. Cold leg tab failures were deemed unacceptable as they could produce debris of broken tabs flowing downstream and blocking flow to the fuel bundle which could result in fuel failure. Thus, a Fitness for Service Evaluation of cracked locking tabs for PNGS A and PNGS B (P-REP-33115-00001 R01) was conducted. This evaluation proved that cold leg locking tabs will not fail prior to 6.3 EFPY. Thus, replacement of the locking tabs must be completed prior to 6.3 EFPY or 2010 (U4) and 2011 (U1).

**Similar Previous Replacement Campaigns**

As mentioned, hot leg locking tab failures were first found in Unit 5. Upon this discovery, all of the sealing skins, locking tabs, and associated components in all Unit 5 steam generators (except for two steam generators which were previously modified in 1999 with a different design) and all Unit 6 steam generators in the following outage (Units 7 and 8 were delayed in order to re-evaluate the repair strategy) were replaced. These repair campaigns were costly, lengthy, and dose intensive:

Unit 5 – approximately $11M, 2 months, 33 Rem (10 steam generators)
Unit 6 – approximately $12M, 2 months, 65 Rem (12 steam generators)

The replacement strategy for PNGS A will focus on locking tab replacement (currently installed sealing skins will be retained), and minimizing cost, time, and dose.

## 3/ ALTERNATIVES AND ECONOMIC ANALYSIS

| [illegible] | [illegible] | Cost | Cost | [illegible] | [illegible] | [illegible] | [illegible] |
|---|---|---|---|---|---|---|---|
| Revenue | (164.5) | - | - | (6.5) | - | | |
| OM&A | (336.5) | (17.7) | (18.0) | (33.5) | | | |
| Capital | - | - | - | - | | | |
| NPV (after tax) | (157.2) | (9.1) | (9.2) | (18.3) | | | |
| Impact on Economic Value (IEV) | N/A | 148.1 | 148.0 | 139.0 | | | |
| IRR% | N/A | 79.2% | 79.2% | 117.2% | | | |
| Discounted Payback (Yrs) | N/A | 5.9 | 5.9 | 6.8 | | | |

### Status Quo - Not Recommended

Status Quo is **not** a recommended option. The Fitness for Service evaluation conducted on the Locking Tabs proved that cold leg locking tabs have a minimum lifespan of 6.3 EFPYs. After 6.3 EFPYs in service, the risk of cold leg locking tab failure increases, thereby increasing the risk to reactor safety. If a cold leg locking tab were to fail, it is speculated that it would cause significant damage to the Heat Transport System, potentially including some components of the reactor core (i.e. fuel bundles). A forced outage would then be required to repair the damage at a projected cost of $100M and duration of 90 days. More importantly, a locking tab failure could potentially affect OPG's good standing with the CNSC and in turn OPG's Power Reactor Operating License (PROL). In addition, beyond 6.3 EFPYs in service, justification for continued operation would be required for Units 1 and 4.

### Alternative 1 - Replace Locking Tabs with new design - Recommended

Replacing the current locking tabs installed in Units 1 and 4 with a new design will allow for the following (which are aligned with the project objectives):

- SGs to run until End of Life (EOL) without the possibility of locking tab failure
- Ability for maintenance to be conducted with minimal interference from the new design which will replace the current locking tabs
- Ability to remove and/or replace components of the new design with relative ease, if required
- Installation to be less complex, optimizing cost, schedule, and dose

The Locking Tab replacement option will be designed with a substantial amount of rigour as per CNE Directive 05-01. As this modification cannot be commissioned, qualification testing along with required analysis will be performed to ensure that the Locking Tab replacement option is robust and will not become Foreign Material.

This is the only alternative which achieves all of the project objectives and in doing so, is this least expensive and has the greatest Net Present Value (NPV).

### Alternative 2 - Delay Project - Not Recommended

Delaying the Project is **not** a recommended option. When the Technical Operability Evaluation (TOE) was first generated, it was determined that all affected units (Units 1, 4, 5, 6, 7, 8) would only be able to operate for 1.8 EFPYs since installation of the locking tabs and sealing skins. OPG Projects pursued locking tab life extension and successfully increased the minimum tab life from 1.8 EFPYs to 6.3 EFPYs. If the project is delayed past 6.3 EFPYs, there is a risk of cold leg locking tab failure which increases over time. As in the Status Quo option, this risk of cold leg locking tab failure is very costly, and has very severe Reactor Safety consequences. There is a slight chance that locking tab failure can be tolerated from a reactor safety point of view beyond 6.3 EFPYs in service, however justification for continued operation of Units 1 and 4 would be required.

Based on the current outage schedules for Units 1 and 4, the Locking Tab replacement will be conducted several months before the end of the minimum tab life (6.3 EFPYs). Thus, there is no benefit to having a separate outage specifically for the Locking Tab replacement, only a few months after the planned outage.

**Alternative 3 – Replace Locking Tabs with Pickering B design - Not Recommended**

Replacing the current locking tabs installed in Units 1 and 4 with a design similar to that of Pickering B (Units 5 and 6) is **not** a recommended option. Although this option allows the SGs to run until EOL without the possibility of locking tab failure, it does not meet all of the other project objectives previously outlined as is shown below:

- The locking tabs installed in Pickering B are welded on the Hot Leg side of the SG Primary Head and thus are not conducive to removal and/or replacement if required during maintenance activities.
- Due to the bolt configuration in the Pickering A SGs (i.e. uneven bolt spacing), installation of locking tabs similar to those in Units 5 and 6 would be quite difficult.
- Replacement of the Units 5 and 6 locking tabs during 2005 involved a tremendous amount of inspections and rework, and hence was costly, time consuming, and dose intensive.

In addition to the above, this option is more costly than Alternative 1. Therefore, replacing the locking tabs with a design similar to Pickering B is not recommended.

**Alternative 4 – - Not Recommended**

**Alternative 5 – - Not Recommended**

## 4/ THE PROPOSAL

A Developmental Release will be used for a mini-campaign (to remove and re-install Clamping Dogs) in support of P711 SG inspections, Preliminary Engineering, to create a contract strategy and complete a Phase 1 BCS.

A Full release will then be requested to:

- Perform the Detailed Engineering
- Award a labour contract (for both units)
- Perform all pre-installation activities for Unit 4 (i.e. workplan preparation, work permits, space allocation, etc.)
- Install, commission, and AFS the modification for Unit 4
- Revise Design Engineering documents as required (i.e. Design ECs, drawings, etc.) for Unit 1
- Start pre-installation activities for Unit 1
- Complete pre-installation activities for Unit 1
- Install, Commission, and AFS the modification for Unit 1
- Close-out the Project

Refer to Appendix C for a list of the project milestones.

## 5/ QUALITATIVE FACTORS

Successful implementation of the locking tab replacement project will eliminate the reactor safety risk inherent to the design of the current cold leg locking tabs. Ease of maintainability will be a consideration during the development of the design.

## 6/ RISKS

| Description of Risk | Description of Consequence | Risk Before Mitigation | Mitigating Activity | Risk After Mitigation |
|---|---|---|---|---|
| **Cost** | | | | |
| Objectives stated in the Developmental BCS will cost more | Unable to accomplish objectives or will require futher release of funds | Low | Clearly defined scope. Regular review of project expenditures. [redacted] contingency available. | Low |
| **Scope** | | | | |
| Preliminary design results in an increase in scope | Change in scope resulting in changes in cost and schedule | High | Scope has clearly been identified through several meetings and a preliminary evaluation of design options. | Medium |
| **Schedule** | | | | |
| Conflict between Boiler activities (Inspection and Locking Tab replacement) | Increase in Outage duration | Medium | Schedule will be optimized to ensure that work is conducted in parallel as much as possible. Divider Plate work has already been moved to 2010 and 2011 to mitigate interference with the Boiler Chemical Clean. | Low |
| **Resources** | | | | |
| Lack of Design Engineering resources | Delay in Design deliverables | Medium | Design support has been committed to this project | Low |
| **Technical** | | | | |
| Locking Tab replacement option does not satisfy all project objectives | Constructability and maintenance issues with design | High | OPG Design and Components and Equipment are actively working together to ensure that an acceptable option is selected. Qualification testing will be done to ensure constructability and maintability issues are addressed and eliminated if possible. | Medium |

| | | | | |
|---|---|---|---|---|
| Locking Tab replacement option fails prior to end of SG life | Potential Foreign Material issue | **Medium** | Locking Tab replacement option will be designed with a substantial amount of rigour as per CNE Directive 05-01. Qualification testing along with required analysis will be performed to ensure that the Locking Tab replacement option is robust and will not become Foreign Material. | **Low** |
| **Regulatory** | | | | |
| This modification does not require regulatory involvement or approval | | | | |
| **Environmental** | | | | |
| N/A | | | | |
| **Health & Safety** | | | | |
| N/A | | | | |
| **Investment** | | | | |
| Locking Tab replacement option interference with low row tube plugging | Removal of locking tab replacement components for low row tube plugging may require significant time and resources | **High** | OPG Design will determine the most viable locking tab replacement option taking into consideration the requirement for access to low row tubes when performing inspections or maintenance. | **Medium** |

## 7/ POST IMPLEMENTATION REVIEW PLAN

| Type of PIR: | Targeted Final AFS Date: | Targeted PIR Approval Date: | PIR Responsibility (Sponsor Title) |
|---|---|---|---|
| Simplified | Jun 2011 | Jul 2015 | Components & Equipment |

**Comments:**

| | Measurable Parameter | Current Baseline | Targeted Result | How will it be measured? | Who will measure it? (person / group) |
|---|---|---|---|---|---|
| 1. | Installation of replacement component(s) during P1041 and P1111 outages | N/A | Components installed during respective outages | Schedule review | PNGS A Components & Equipment |
| 2. | Reliable performance (100% non-failure) of components to end of SG/plant life. | 6.3 EFPYs | Non-failure of components during life of SGs | 1. Inspection of components during first and second SG inspection outages following replacement.<br>2. Confirmed non-failure at subsequent outages to end of SG life. | PNGS A Components & Equipment |
| 3. | | | | | |
| 4. | | | | | |
| 5. | | | | | |

**Appendix "A"** **Glossary** (acronyms, codes, technical terms)

- AFS: Available for Service
- CNSC: Canadian Nuclear Safety Commission
- EC: Engineering Change
- EFPY: Effective Full Power Year
- EOL: End of Life
- HTS: Heat Transport System
- NPV: Net Present Value
- RIHT: Reactor Inlet Header Temperature
- PNGS: Pickering Nuclear Generating Station
- PROL: Power Reactor Operating License
- SG: Steam Generator
- TOE: Technical Operability Evaluation

## Appendix "B" Project Funding History

| $ 000's | | | Previous Releases (incl contingency) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Cumulative Values | | | | | | | |
| **Release Type** | **Month** | **Year** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **Later** | **Total** |
| Developmental | | | | 850 | 385 | 520 | 7,675 | 7,905 | 400 | | 17,735 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| LTD Spent | | | | | | | | | | | 0 |

**Comments:**

The Developmental Release will be used to cover the cost of a mini-campaign to support P711 SG inspections and complete ~40% of the design. The Full Release will be used to complete 100% of the design, install, commission, AFS the modification in Unit 4. Additionally, it will be used to prepare for Unit 1, install, commission, and AFS the modification in Unit 1, as well as complete Project Close-out.

## Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

For the majority of engineering and design work, overtime has been assumed to be 10%. For field personnel, overtime has been assumed to be 25%.

Financial Assumptions:

The rate of inflation estimated at 2% is consistent with Corporate guidelines.

Project / Station End of Life Assumptions:

Based on a memo to D. Power from P.R. Charlebois, "Pickering Units 1 & 4 End of Service Life Predictions for Establishing Book Value", January 12, 2006, we have assumed that Station End of Life for Units 1 and 4 will be in 2021, thus requiring replacement of the Locking Tabs during 2011 and 2010 respectively.

It is assumed that the Locking Tab replacement modification will be conducted during Fall 2010 for Unit 4 and Fall 2011 for Unit 1.

It is assumed that the majority of design work will be completed well before the 2009 outage milestone.

Energy Price / Production Assumptions

The price of energy is estimated based on Corporate System Economic Values. Production from each Pickering A unit is assumed to be 516 MW at a capacity factor of 80%.

Operating Cost Assumptions

N/A

Other Assumptions:

It is assumed that if a Cold Leg locking tab were to fail, it would cause damage to the Heat Transport System (HTS). The forced outage required to repair the HTS is assumed to cost $100M and be 90 days in duration.

The risk of Cold Leg locking tab failure is assumed to be 5% starting in 2011 (U4) and 2012 (U1) and increasing at a rate of 5% per year.

The probability of Cold Leg locking tab failure in Units 1 and 4 simultaneously is too low to be considered. If a failure were to occur in one unit, the 2nd unit would be shut down immediately.

## Pickering A Steam Generator Locking Tab Replacement 13 - 49248

## Developmental Release Business Case Summary NA44-BCS-33115-00001-R000

**Attachment "A"** **Project Cost Summary**

| $000's OM&A | LTD Prior Yr 2006 | This Release 2007 | This Release 2008 | Future Release 2009 | Future Release 2010 | Future Release 2011 | Future Release 2012 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|
| Project Management (OPG) | - | 221 | 175 | 137 | 395 | 434 | 177 | | 1,539 |
| Engineering & Drafting (OPG) | - | | 160 | 86 | 157 | 168 | 96 | | 666 |
| Material | - | 120 | | | 150 | 125 | | | 395 |
| Installation - PWU, BTU | - | 125 | | 97 | 610 | 615 | 28 | | 1,475 |
| Contract - Design | - | | | | | | | | - |
| Contract - Installation | - | 234 | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Contract - Other | - | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Installation - IMS | - | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Kinectrics | - | | | | | | | | - |
| Interest (Capital Project Only) | | | | | | | | | - |
| **Project Costs (excl contingency)** | - | 700 | 335 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| General Contingency | | 150 | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Specific Contingency | | | | | | | | | - |
| **Project Costs (incl contingency)** | - | 850 | 385 | 520 | 7,675 | 7,905 | 400 | - | 17,735 |
| 2007-2011 Business Plan | | 300 | 100 | 500 | 7,100 | 7,100 | 300 | | 15,400 |
| **Variance to Business Plan** | - | 400 | 235 | (160) | 75 | 105 | - | - | [illegible],835 |
| Committed Cost | | | | | | | | | - |
| Inventory Write Off Required | | | | | | | | | - |
| Spare Parts / Inventory | | | | | | | | | - |
| **Total Release (excl contingency)** | - | 700 | 335 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Total Release (incl contingency)** | - | 850 | 385 | 520 | 7,675 | 7,905 | 400 | - | 17,735 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Ongoing OM&A (non-project)** | | | | | | | | | - |
| **Removal Costs (incl in above)** | | | | | | | | | - |

**Basis of Estimate**

| | | | | | |
|---|---|---|---|---|---|
| Design Complete | Up to - 40% | | Quality of Estimate | Conceptual + 60% to - 25% | |
| 3rd Party Estimate | N/A | OPEX used | Yes | Lessons Learned | Yes |
| Reviewed by Sponsor | Yes | Budgetary Quote(s) | No | Phase 1 Actual Used | N/A |
| Similar Projects | Yes | Contracts in place | N/A | Competitive Bid | N/A |

**Variance to Business Plan**

The estimated variance(s) to the 2006-2010 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by May 2007.

Reviewed By:

Pejman Asgaripour
Project Manager

APR/2[illegible]/2007
Date:

Approved By:

Jerry Keto
Jerry Keto
Eng & Mods Manager (Strat IV)

16 April 2007
Date:

## Pickering A Steam Generator Locking Tab Replacement 13 - 49248

## Developmental Release Business Case Summary NA44-BCS-33115-00001-R000

**Attachment "B"** **Project Variance Analysis**

| OM&A | LTD | Choose One |  | Variance | Comments |
|---|---|---|---|---|---|
|  | N/A<br>N/A | Last BCS<br>N/A<br>N/A | This BCS<br>Sep<br>N/A |  |  |
| Project Management (OPG) |  |  |  | 0 |  |
| Engineering & Drafting (OPG) |  |  |  | 0 |  |
| Material |  |  |  | 0 |  |
| Installation - PWU, BTU |  |  |  | 0 |  |
| Contract - Design |  |  |  | 0 |  |
| Contract - Installation |  |  |  | 0 |  |
| Contract - Other |  |  |  | 0 |  |
| Kinectrics |  |  |  | 0 |  |
|  |  |  |  | 0 |  |
| Interest (Capital Project Only) |  |  |  | 0 |  |
| **Project Costs (excl contingency)** | 0 | 0 | 0 | 0 |  |
| General Contingency |  |  |  | 0 |  |
| Specific Contingency |  |  |  | 0 |  |
| **Project Costs (incl contingency)** | 0 | 0 | 0 | 0 |  |
| Committed Cost |  |  |  | 0 |  |
| Inventory Write Off Required |  |  |  | 0 |  |
| Spare Parts / Inventory |  |  |  | 0 |  |
| **Total Release (incl contingency)** | 0 | 0 | 0 | 0 |  |
| **Total Release (excl contingency)** | 0 | 0 | 0 | 0 |  |

|  |  |  |  |  |  |
|---|---|---|---|---|---|
| **Ongoing OM&A (non-project)** |  |  |  | 0 |  |
| **Removal Costs (incl in above)** |  |  |  | 0 |  |

**Comments:**

This project was identified in June 2005. Currently, conceptual funding is being used to perform minimal design work and to generate the Developmental BCS.

**Attachment "C"** **Key Milestones**

| Completion Date | | | Description |
|---|---|---|---|
| Day | Mth | Yr | |
| 30 | Apr | 2007 | BCS: Developmental Release Approved |
| 30 | Jun | 2007 | PSM: Plan Start Milestone |
| 16 | Oct | 2007 | SOI: Start of mini Field Campgain (P711 Clamping Dog Removal/Re-install) |
| 30 | Apr | 2008 | FR1: Full Release BCS Approved |
| 15 | Apr | 2009 | FD1: Final Design Complete (Unit 1 and Unit 4) |
| 15 | May | 2009 | MCA: Major Contracts Awarded |
| 15 | Apr | 2010 | SOI: Start of Installation (Unit 4) |
| 30 | Jun | 2010 | AFS: Available for Service Meeting (Unit 4) |
| 31 | Dec | 2010 | ECC: EC Close-out (Unit 4) |
| 31 | Mar | 2011 | SOI: Start of Installation (Unit 1) |
| 15 | Jun | 2011 | AFS: Available for Service Meeting (Unit 1) |
| 27 | Jun | 2011 | PCS: Close-out Starts |
| 21 | Dec | 2011 | PCM: Plan Complete Milestone |

A Project Execution Plan (PEP) will be approved by Jul 2008

**Comments:**

All applicable milestones will be in accordance with N-PROC-MA-0013 (Planned Outage Management) as the locking tab replacement will be conducted during the 2010 and 2011 outages.

## Probabilistic Safety Assessment Upgrade 10 - 62440

## Partial Release Business Case Summary N-BCS-03500-10000-R000

## 1/ RECOMMENDATION:

Approval is requested for a partial release of $11.3 Million (including contingency) OM&A project funding to initiate the upgrading the Darlington, Pickering A and Pickering B Probabilistic Safety Assessments (PSA - also known as Probabilistic Risk Assessment or PRA).

The business objectives of this project are to:

- Upgrade the Darlington and Pickering B Probabilistic Safety Assessments to bring them into compliance with their current Power Reactor Operating Licenses. The respective operating Licenses for both stations (revised and reissued by the CNSC in 2008) mandate that by December 31, 2010, each station must have a PSA that is compliant with the requirements of CNSC Regulatory Standard S-294 "Probabilistic Safety Assessment (PSA) for Nuclear Power Plants". The development, maintenance and use of PSA is also mandated by the requirements of the Corporate Nuclear Safety Policy and by the requirements of the corporate Risk and Reliability Program N-PROG-RA-0016.
- Upgrade the Pickering A Probabilistic Safety Assessment to be compliant with Regulatory Standard S-294, which is anticipated to be required in the Pickering A Power Reactor Operating License renewal in 2010.
- Develop sustainable in-house PSA expertise which will support:
    - The regulatory trend towards risk-based decision making in relation to assessment of emergent plant issues
    - The industry trend towards use of PSA for business risk assessments and for business optimization decisions related to on-line and outage maintenance strategies and scheduling.

The cost estimate is based on a project execution plan provided by the primary contractor and input from potential secondary contractors. Costing is based on experience to date with recent risk model upgrades and projected costs for inclusion of evaluation of internal events such as fire and external events such as seismic incidents.

The funding estimate also includes the requirements for OPG staff for project management and station support staff (7 full time equivalents) up to the end of 2010 to provide expert detailed review of contractor product and to develop a sustaining in-house expertise in the PSA field.

| $000's (incl contingency) | Funding | LTD 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|
| Currently Released | None | - | - | - | - | - | - | - | - |
| Requested Now | Partial | - | 1,800 | 10,200 | - | - | - | - | 12,000 |
| Future Funding Req'd | Full | - | | | 10,400 | 4,400 | - | - | 14,800 |
| Total Project Costs | | - | 1,800 | 10,200 | 10,400 | 4,400 | - | - | 26,800 |
| Other Costs | | | | | | | | | - |
| Ongoing Costs | | | | | | | | | - |
| Grand Total | | - | 1,800 | 10,200 | 10,400 | 4,400 | - | - | 26,800 |
| Investment Type | | Class | | (IEV) Impact on Ec Value | | IRR | | Discounted Payback | |
| Regulatory | | OM&A | | (15,800) | | N/A | | N/A | |

Submitted By:

RCMorrison 8 Sep 08

R.C. Morrison Date:
Vice President & Chief Nuclear Engineer

Finance Approval:

D. Hanbidge Date:
Senior Vice President & Chief Financial Officer

Line Approval (Per OAR Element 1.2 Project not in Budget):

J. Hankinson Jan 9/09 Date:
President & Chief Executive Officer

## 2/ BACKGROUND & ISSUES

In April 2005 following industry consultation (including OPG through the CANDU Owners Group), the Canadian Nuclear Safety Commission published Regulatory Standard S-294 which mandates that each nuclear power plant licensee carry out plant specific Level 2 Probabilistic Safety Assessments. A probabilistic safety assessment (also known as a probabilistic risk assessment) is a comprehensive and integrated assessment of the safety of the plant or reactor. The safety assessment considers the probability, progression and consequences of equipment failures or transient conditions to derive numerical estimates that provide a consistent measure of the safety of the plant or reactor. The regulatory standard requires that Canadian utilities have probabilistic safety assessments consistent with international standards. During the review process, the industry questioned need for a probabilistic safety assessment when there was no regulatory context for their usage. The regulator decided on a step-wise process whereby the probabilistic safety assessments will be put in place first to be followed by risk limits and processes.

A Level 1 probabilistic safety assessment identifies and quantifies the sequence of events that may lead to the loss of core structural integrity and massive fuel failures. A Level 2 probabilistic safety assessment starts from the Level 1 results and provides an analysis of containment behaviour, the radionuclides released from the failed fuel and a quantification of releases to the environment.

The Darlington and Pickering B Power Reactor Operating Licenses, as revised and re-issued by the Canadian Nuclear Safety Commission in 2008, mandate that both stations must have a probabilistic safety assessment compliant with the requirements of Regulatory Standard S-294 by December 2010. (Discussions between OPG and regulatory staff prior to the Darlington license re-issue had suggested that the license condition would be to provide a plan to bring it into compliance with S-294 with 2012 as the planned completion.) It is anticipated that an S-294 compliant probabilistic safety assessment will be required for Pickering A in the next issuance of its Power Reactor Operating License in 2010.

The Corporate Nuclear Safety Policy and Corporate Risk and Reliability Program also mandate the development, maintenance and use of probabilistic safety assessments. Probabilistic safety assessments will support the regulatory trend towards risk-informed decision making. Industry experience in jurisdictions requiring Level 2 probabilistic safety assessments indicates that risk-informed decision making has resulted in relaxation of deterministic limits to continuing operation, thereby avoiding shutdowns that otherwise would have occurred. Probabilistic safety assessments will also be required to support regulatory approvals of plant life extensions.

The Darlington Probabilistic Safety Evaluation was issued in 1987 and a "draft" Darlington Risk Assessment was developed. This draft document, although in current use, requires a major revision in order to accurately reflect current plant operation and to comply with the specifications of Regulatory Standard S-294. Preliminary work on the Darlington upgrade is currently in progress.

The Pickering B Risk Assessment was updated and issued in 2007. This probabilistic safety assessment is essentially compliant with Level 1 and Level 2, but requires revision to address regulatory comments.

The current Pickering A Power Reactor Operating License does not require an S-294 compliant assessment. The Pickering A Probabilistic Risk Assessment requires updating of the Level 1 and Level 2 analyses to bring it into compliance with Regulatory Standard S-294.

The existing probabilistic risk assessments have already been used to improve public safety, as discussed in examples below, and the upgrades are expected to identify additional areas for improvement.

- The Pickering A probabilistic risk assessment was used to identify improvements and support restart following Unit 1 and Unit 4 refurbishment.
- The work completed on the Darlington upgrade has already identified gaps in operating documentation and surveillance programs as well as deficiencies that were addressed through operability evaluations.

Due to the increased complexity and cost imposed by the new license conditions and the compressed time frame for completion, it is proposed to manage the upgrade to license compliance as a project, with appropriate project management, augmentation of resources, vendor oversight and station support staffing.

## 3/ ALTERNATIVES AND ECONOMIC ANALYSIS

| $ 000's | Status Quo | Alt 1 (Recommended) | | Alt 2 | Alt 3 | Alt 4 | Alt 5 |
|---|---|---|---|---|---|---|---|
| | | Full Cost | Incremental Cost | Delay | | | |
| Revenue | | | | | | | |
| OM&A | | (26,800) | (26,800) | (18,800) | | | |
| Capital | | | | | | | |
| NPV (after tax) | | (15,896) | (15,896) | (14,951) | | | |
| Impact on Economic Value (IEV) | N/A | (15,896) | (15,896) | (14,951) | | | |
| IRR% | N/A | N/A | N/A | N/A | | | |
| Discounted Payback (Yrs) | N/A | N/A | N/A | N/A | | | |

### Status Quo - Not Recommended

Status quo is not recommended. The current Darlington and Pickering B PSAs currently do not comply with S-294 requirements. Darlington and Pickering B will be in non-compliance with their respective PROL license conditions as of Dec 31, 2010 and risk regulatory action. The CNSC will most probably impose the S-294 compliance on Pickering A in its next PROL. There is very low probability that the CNSC will rescind the regulatory document or license condition requiring a level 2 PSA.

### Alternative 1 - Complete PSA to Meet License Conditions - Recommended

Upgrade the Darlington and Pickering B Probabilistic Safety Assessments to bring them into compliance with Regulatory Standard S-294 by their respective compliance dates. Upgrade the Pickering A Probabilistic Safety Assessment to bring into compliance with anticipated regulatory requirement. Provide corporate project management and oversight, create separate station organization to execute the project, interface with the regulator and to provide vendor support through to completion.

### Alternative 2 - Delay Project - Not Recommended

Delay of project is not recommended as the schedule completion by the license date is already at risk. The probability of acquiring a license amendment extending the deadline for full compliance is very low unless significant progress can be shown.

### Alternative 3 – - Not Recommended

NA

### Alternative 4 – - Not Recommended

NA

### Alternative 5 – - Not Recommended

NA

## 4/ THE PROPOSAL

This release of the project will initiate the work to update the probabilistic safety assessments of Darlington and Pickering B to bring them into compliance with Regulatory Standard S-294 by Dec 31, 2010 as mandated by the respective current Power Reactor Operating Licenses, and begin work on the Pickering A probabilistic safety assessment as described below

**Develop S-294 Compliant Probabilistic Safety Assessment for Darlington**

The probabilistic safety assessment of Darlington will be upgraded in four interdependent phases, as listed below.

- Phase 1: Update Level 1 probabilistic safety assessments (excluding fire and seismic events).
- Phase 2: Develop Level 2 probabilistic safety assessment models (excluding fire and seismic events).
- Phase 3: Address remaining S-294 gap issues including disposition of other external events such as airplane crash, intense precipitation, tornadoes, rail line explosion, rail line toxic gas release, transportation accident, low lake level, meteorite strike, and geomagnetic storms.
- Phase 4: Develop Level 1 and Level 2 assessment models for fire and seismic events.

**Develop S-294 Compliant Probabilistic Safety Assessment for Pickering B**

This phase of the project will revise the existing probabilistic safety assessment to address regulatory comments and initiate work on Level 1 and Level 2 fire and seismic probabilistic safety assessment, along with disposition of other external events described above. The extent of the probabilistic safety assessment will depend on the end-of-life decision for Pickering B.

**Develop S-294 Compliant Probabilistic Safety Assessment for Pickering A**

This phase of the project will be to begin the update the Level 1 probabilistic safety assessment to incorporate identified issues, design changes such as permanent Inter-Station Transfer Bus design, incorporation of Unit 2 and Unit 3 Safe Storage end states and other design changes as well as development of the data file necessary for the Level 2 analysis.

**Develop Sustainable Internal Expertise for Probabilistic Safety Assessment**

Develop sustainable internal probabilistic safety assessment expertise which will support:

- Risk-informed decision making on regulatory issues and response to emergent plant conditions.
- Business risk assessments and optimization decisions.

The project will meet the following overall requirements:

1. A formal quality assurance process for completing a probabilistic safety assessment will be established and applied.
2. Models will reflect the plant as built and operated as closely as reasonably achievable within limitations of probabilistic safety assessment technology and consistent with risk impact.
   - Both internal and external events will be included.
   - At-power and shutdown modes will be included.
   - Sensitivity analysis, uncertainty analysis and importance measures will be included.
3. Models will be developed using assumptions and data that are realistic and practical.
4. The level of detail of the probabilistic safety assessment will be consistent with plant testing and configuration management programs.
5. Canadian Nuclear Safety Commission acceptance of the methodology and computer codes to be used for the probabilistic safety assessment will be obtained.

The project cost is based on vendor budgetary estimates, and experience with preliminary vendor work on PSA revision and considers the increased complexity imposed by the requirement for S-294 compliance and increased scope required to complete the fire and seismic portions of the PSA.

The estimate includes the cost to establish corporate oversight and to create dedicated PSA project teams at the stations to manage and execute the project, provide oversight of vendor activities and costs, provide expert review of vendor product, to provide regular interface with the regulator and for the development of a sustaining in house PSA capability.

Seven Full Time Equivalent employees (FTEs) are required on the station project teams for the duration of the project

## 5/ QUALITATIVE FACTORS

The existing probabilistic risk assessments have already been used to improve public safety, as discussed in examples below, and the upgrades are expected to identify additional areas for improvement.

- The Pickering A probabilistic risk assessment was used to identify improvements and support restart following Unit 1 and Unit 4 refurbishment.
- The work completed on the Darlington upgrade has already identified gaps in operating documentation and surveillance programs as well as deficiencies that were addressed through operability evaluations.

## 6/ RISKS

| Description of Risk | Description of Consequence | Risk Before Mitigation | Mitigating Activity | Risk After Mitigation |
|---|---|---|---|---|
| **Cost** | | | | |
| Complexity of analysis is greater than expected | Budgeted cost exceeded | **High** | Project team to determine acceptable level of complexity.<br>Contingency funding identified in this BCS | **Low** |
| **Scope** | | | | |
| Fire and Seismic PSA not required in previous regulation | Amount of work is more than anticipated resulting higher than budgeted costs | **High** | Initiate as soon as possible and use vendor with previous experience in seismic / fire assessments.<br>Contingency funding identified in this BCS. | **Low** |
| Analysis reveals situations that require shutdown of one or more units. | Loss of revenue and increased costs while solution to analysed condition is implemented. | **High** | Discovery Issue Resolution Process and Technical Operability Evaluation processes will be used to address issues identified during analysis.<br>Analysis will also support risk-informed decisions by the regulator on increasing the duration of shutdown clocks. | **Low** |
| Analysis reveals safety deficiencies that require plant modifications to address. | Increased costs as modifications are implemented | **Medium** | Analysis will be used to support risk-informed decisions on proceeding with plant modifications.<br>Proposed modifications will be assessed and prioritized by the AISC process to ensure spending ceilings are maintained. | **Low** |
| **Schedule** | | | | |
| Rework of submitted analyses | Delay in completing analysis work with potential to miss license condition. | **High** | Use staged reviews to minimize rework time. | **Low** |

| Description of Risk | Description of Consequence | Risk Before Mitigation | Mitigating Activity | Risk After Mitigation |
|---|---|---|---|---|
| **Resources** | | | | |
| There is a limited pool of experienced probabilistic risk analysts in Canada. | Completing the required analysis by the Darlington and Pickering B license condition date may be missed due to the volume of work. | **High** | Update of the Level 1 and 2 internal event analyses to be completed by the current vendor of probabilistic risk assessment services.<br>Development of the fire, seismic and other external event analyses to be sourced from vendors in Canada and the United States with experience in fire and seismic analysis.<br>Third party review of the analyses will be sourced from vendors in the United States. | **Low** |
| **Technical** | | | | |
| Quality / Methodology | Schedule delay | **High** | Vendor to use industry standard methodology. Station Team to review vendor product. Independent Third Party review. | **Low** |
| **Regulatory** | | | | |
| Regulator rejects analysis due to methodology, data and assumptions | Delay in completing analysis work with potential to miss license condition. | **High** | Staged review by regulator. Establish update process similar to Safety Report update. Vendor to use industry standard methodology. Third party review. Experienced vendors. | **Low** |

## 7/ POST IMPLEMENTATION REVIEW PLAN

| Type of PIR: | Targeted Final AFS Date: | Targeted PIR Approval Date: | PIR Responsibility (Sponsor Title) |
|---|---|---|---|
| TBD in Next Release | TBD in Next Release | TBD in Next Release | |

**Comments:**

| | Measurable Parameter | Current Baseline | Targeted Result | How will it be measured? | Who will measure it? (person / group) |
|---|---|---|---|---|---|
| 1. | | | | | |
| 2. | | | | | |
| 3. | | | | | |
| 4. | | | | | |
| 5. | | | | | |

## Appendix "A" Glossary (acronyms, codes, technical terms)

CNSC: Canadian Nuclear Safety Commission

DARA: Darlington A Risk Assessment

Level 1 PSA: Probabilistic Safety Assessment of Core Damage Frequency

Level 2 PSA; Probabilistic Safety Assessment of Large Release Frequency

NSS: Nuclear Safety Solutions

PRA: Probabilistic Risk Assessment

PSA: Probabilistic Safety Assessment

PROL: Power Reactor Operating License

S-294: CNSC Regulatory Standard – Probabilistic Safety Assessment for Nuclear Power Plants

## Appendix "B" Project Funding History

| $ 000's | | All Existing and Planned Releases (incl contingency) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Cumulative Values | | | | | | | | | |
| Release Type | Month | Year | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | Later | Total |
| Partial | Jul | 2008 | 1,800 | 10,200 | 10,400 | 4,400 | | | | | 26,800 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | 0 |
| | | | | | | | | | | | |
| LTD Spent | Jul | 2008 | 0 | | | | | | | | 0 |

**Comments:**

## Appendix "C" Financial Model – Assumptions

### Project Cost Assumptions:

- Schedule is mandated by licensing requirements
- 1 Project Manager (Corporate) and 6 FTE's (Station Based) to support project over duration of the project
- Contract value based on budgetary estimates provided by vendors

### Financial Assumptions:

- Annual cashflows dependant on resource availability, timeliness of contract award, vendor capability and mobilization.

### Project / Station End of Life Assumptions:

### Energy Price / Production Assumptions:

### Operating Cost Assumptions:

### Other Assumptions:

## Probabilistic Safety Assessment 10 - 62440

## Partial Release Business Case Summary N-BCS-03500-10000-R000

**Attachment "A"** **Project Cost Summary**

| $000's OM&A | LTD Prior Yr 2007 | This Release 2008 | This Release 2009 | Future Release 2010 | Future Release 2011 | | | Later | Total |
|---|---|---|---|---|---|---|---|---|---|
| Project Management (OPG) | - | 100 | 200 | 200 | 100 | | | | 600 |
| Engineering & Drafting (OPG) | - | 300 | 1,000 | 1,200 | 300 | | | | 2,800 |
| Material | | | | | | | | | - |
| Installation – PWU, BTU | | | | | | | | | - |
| Contract - Design | | | | | | | | | - |
| Contract - Installation | | | | | | | | | - |
| Contract - Analysis Services | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | | | | | | | | - |
| | | | | | | | | | - |
| Interest (Capital Project Only) | | | | | | | | | - |
| **Project Costs (excl contingency)** | - | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| General Contingency | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Specific Contingency | | | | | | | | | - |
| **Project Costs ( incl contingency)** | - | 1,800 | 10,200 | 10,400 | 4,400 | - | - | - | 26,800 |
| 2008-2012 Business Plan | | - | - | - | | | | | - |
| **Variance to Business Plan** | - | 1,500 | 9,200 | 9,400 | 3,900 | - | - | - | 24,000 |
| Committed Cost | | | | | | | | | - |
| Inventory Write Off Required | | | | | | | | | - |
| Spare Parts / Inventory | | | | | | | | | - |
| **Total Release (excl contingency)** | - | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Total Release (incl contingency)** | - | 1,800 | 10,200 | 10,400 | 4,400 | - | - | - | 26,800 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Ongoing OM&A (non-project)** | | | | | | | | | - |
| **Removal Costs (incl in above)** | | | | | | | | | - |

| **Basis of Estimate** | | | | | |
|---|---|---|---|---|---|
| Design Complete | Zero to Minimal | | Quality of Estimate | Conceptual + 60% to - 25% | |
| 3rd Party Estimate | Yes | OPEX used | Yes | Lessons Learned | Yes |
| Reviewed by Sponsor | | Budgetary Quote(s) | Yes | Phase 1 Actual Used | No |
| Similar Projects | | Contracts in place | | Competitive Bid | |

**Variance to Business Plan**

The estimated variance(s) to the 2008-2012 Business Plan will be addressed through the portfolio management process A PCRAF is not required

Reviewed By: Approved By:

P Lawrence
Project Manager Date:

Y. Sirota
Manager. Reactor Safety Date:

## Probabilistic Safety Assessment Upgrade 10 - 62440

## Partial Release Business Case Summary N-BCS-03500-10000-R000

**Attachment "B"** **Project Variance Analysis**

| OM&A | LTD | Partial Release | | Variance | Comments |
|---|---|---|---|---|---|
| | N/A<br>N/A | Last BCS<br>N/A<br>N/A | This BCS<br>Jul<br>2008 | | |
| Project Management (OPG) | | | | 0 | |
| Engineering & Drafting (OPG) | | | | 0 | |
| Material | | | | 0 | |
| Installation – PWU, BTU | | | | 0 | |
| Contract - Design | | | | 0 | |
| Contract - Installation | | | | 0 | |
| Contract - Other | | | | 0 | |
| | | | | 0 | |
| | | | | 0 | |
| Interest (Capital Project Only) | | | | 0 | |
| **Project Costs (excl contingency)** | 0 | 0 | 0 | 0 | |
| General Contingency | | | | 0 | |
| Specific Contingency | | | | 0 | |
| **Project Costs ( incl contingency)** | 0 | 0 | 0 | 0 | |
| Committed Cost | | | | 0 | |
| Inventory Write Off Required | | | | 0 | |
| Spare Parts / Inventory | | | | 0 | |
| **Total Release (incl contingency)** | 0 | 0 | 0 | 0 | |
| **Total Release (excl contingency)** | 0 | 0 | 0 | 0 | |
| | | | | | |
| **Ongoing OM&A (non-project)** | | | | 0 | |
| **Removal Costs (incl in above)** | | | | 0 | |

**Comments:**

As this is the first release for this project, the variance analysis is not applicable.

## Attachment "C" Key Milestones

| Completion Date | | | Description |
|---|---|---|---|
| Day | Mth | Yr | |
| 01 | 09 | 08 | Initiating Events identified and frequency calculated. |
| 30 | 09 | 08 | Detailed PEP issued. |
| 28 | 02 | 09 | Event Tree analysis completed. |
| 30 | 03 | 09 | Screening analysis for low frequency external events completed. |
| 31 | 06 | 09 | Fault Tree analysis completed. |
| 31 | 12 | 09 | Level 1 Integration completed. |
| 31 | 03 | 10 | Level 1 fire PRA completed. |
| 31 | 06 | 10 | Seismic margin assessment completed. |
| 31 | 06 | 10 | Containment fault trees completed. |
| 31 | 10 | 10 | Level 2 PRA completed. |
| | | | |
| | | | |
| | | | |

A Project Execution Plan (PEP) will be approved by September 2008.

**Comments:**

## Fuel Channel Life Management 10 - 62444

## Partial Release Business Case Summary N - BCS - 31100 - 10001 – R000

## 1/ RECOMMENDATION:

We recommend a Partial Release of $12.3 Million OM&A for the Fuel Channel Life Management Project. A request for the remainder of the project cost (estimated at $12.7M) will be submitted in August 2010 when more certainty of the full scope and cost of the total project will be developed. This project is jointly funded between OPG and Bruce Power.

Fuel channel pressure tubes in most OPG CANDU units are beginning to approach their nominal operating life of 210k Equivalent Full Power Hours (EFPH). Accordingly, the prospect of multi-unit stations requiring refurbishment within a few years of each other is a growing concern because that would lead to competition for scarce re-tubing resources to support concurrent refurbishment operations. As a result, OPG is considering alternatives to achieve greater value from operating units and provide greater planning flexibility.

Moreover, due to the various degradation mechanisms related to fuel channels, the exact criteria for end-of-life or when fitness-for-service limits will be reached are not well defined. The methodologies, models and their bases currently used to demonstrate fuel channel fitness-for-service may not be adequate for late life assessments. In addition, there is an insufficient amount of inspection data and test results from ex-service pressure tube material on which to base projections. For these reasons, OPG fuel channel experts currently do not have a high level of confidence that the Darlington units can exceed 187k EFPH.

At this time, fuel channel R&D to support fitness-for-service is conducted through COG work packages which address the needs of all COG partners. However, if the pace of these COG activities is not accelerated and tailored to satisfy the specific objectives of OPG, the possible refurbishment start date of Darlington may need to be advanced to 2014 from the current planning scenario start date of 2016. As it takes more than 5 years to plan such a major undertaking, adequate lead time for a possible start date of 2014 would already be an issue.

The objective of this project is to have high confidence that Darlington can operate to 210k EFPH or beyond and that Pickering B can operate to 240k EFPH or beyond. This partial release will allow the critical path/long lead items to be initiated with the appropriate contractors to provide the results by 2012 which will subsequently support development of technical basis documents for continued fitness-for-service.

This project will accelerate some work being conducted through the CANDU Owners Group (COG) Research & Development (R&D) program as well as resolve issues which are outside of the general COG scope. The activities which will be initiated with this Partial Release includes the following key elements (to the end of 2010):

1. The first 1-1.5 years of a four year COG Joint Project with AECL and Bruce Power (BP) to conduct burst tests on ex-service pressure tubes to determine their fracture toughness at end-of-life (EOL) conditions;
2. Additional fracture toughness tests to support EOL limits
3. Defining annulus spacer surveillance requirements for subsequent testing/examination activities when pressure tubes and spacers are removed;
4. The first 1-1.5 years of 2 and 3 year experimental programs on pressure tube crack initiation to improve the basis for modifying the fitness-for-service methodologies and demonstrate increased margin to crack initiation.

| $M (incl contingency) | Type | LTD 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|
| Currently Released | None | | | | | | | | - |
| Requested Now | Partial | | 2,533 | 9,728 | | | | | 12,261 |
| Future Funding Req'd | Full | | | | 7,741 | 4,010 | 908 | | 12,659 |
| Total Project Costs | | - | 2,533 | 9,728 | 7,741 | 4,010 | 908 | - | 24,920 |
| Non Project Costs | | | | | | | | | - |
| Grand Total | | - | 2,533 | 9,728 | 7,741 | 4,010 | 908 | - | 24,920 |

| Investment Type | Class | NPV | IRR | Discounted Payback |
|---|---|---|---|---|
| Value Enhancing | OM&A | 2,198 | N/A | N/A |

Submitted By:

for W. Robbins
Chief Nuclear Officer

Date: 27 July 09

Finance Approval:

D. Hanbidge
SVP & Chief Financial Officer

Date:

Line Approval (Per OAR Element 1.2 Project not in Budget):

T. Mitchell
President & Chief Executive Officer

10 Aug 2009
Date:

## 2/ BACKGROUND & ISSUES

Although the life limiting pressure tube degradation mechanisms vary slightly between stations (See Project Charter), this can change over time and the degradation mechanisms listed below have an impact on pressure tubes at both Pickering B and Darlington.

This type of R&D work is typically eligible for Scientific R&D tax credit, and one will be pursued to reduce the overall cost to OPG.

***Deuterium ingress and its impact on material properties***

During hot operation, fuel channel pressure tubes react with the heavy water coolant and, as a consequence of this, the concentration of hydrogen (deuterium and protium quoted in terms of the equivalent hydrogen concentration, $H_{eq}$) increases over time. As well, in the pressure tube/end fitting rolled joint region, there is an additional galvanic corrosion component which makes the process in this region much more rapid. Since pressure tube material has a limited solubility of hydrogen which increases with increasing temperature, the brittle hydride phase is present during unit heat-up and cool-down transients - which makes fuel channel pressure tubes susceptible to an active cracking mechanism, delayed hydride cracking (DHC). As well, it is unknown whether the $H_{eq}$ anticipated to be found later in fuel channel life will have an adverse impact on the mechanical properties of pressure tubes.

Due to the limited fracture toughness data available for high $H_{eq}$ conditions, CSA N285.8 limits the allowable $H_{eq}$ in the main body of a pressure tube (BOT) and in the tensile portion of the rolled joint (RJ) region to 70 ppm at the inlet and 100 ppm at the outlet. These values are therefore referred to as "End-of-Life" (EOL) limits. Although these are currently hard limits, operation below this value (but above the solubility limit) cannot be supported with the available data.

As a result, OPG fuel channel experts have only medium confidence (up to 70%) that the pressure tubes in Darlington will achieve its nominal operating life of 210k EFPH. This is due to a lack of scrape data from the Darlington Units to support model predictions, the fact that Darlington Unit 3 scrape samples in 2002 exhibited some very high uptake trends that exceeded the upper bound of the CANDU 6 model, and that Darlington pressure tubes have some of the highest initial impurity hydrogen ($H_{initial}$) values in any CANDU units. Other contributing factors include a scarcity of rolled joint $H_{eq}$ data and the lack of a predictive rolled joint model. If the currently defined EOL limits are reached in Darlington earlier than 210k EFPH, then it may be necessary to advance the refurbishment schedule from the current plan of 2016 to as early as 2014. As it takes more than 5 years to organize for such a major undertaking, adequate lead time to start in 2014 is already an issue (as illustrated in Attachment D). In addition, there is a significant loss in economic value if the Darlington units need to be refurbished earlier. Aside from issues concerning reaching this limit, it should be recognized that there little high hydrogen material property data from ex-service pressure tubes. Hence, there is insufficient data to provide the needed technical basis supporting operation of pressure tubes with $H_{eq}$ above the solubility limit and beyond.

Until recently, Pickering B was not expected to exceed the EOL limits during the pressure tube nominal operating life of 210k EFPH. This expectation was related to the lower operating temperatures in Pickering B. However, the hydrogen and deuterium profiles through the inlet and outlet rolled joint regions of surveillance tube P6 M14 have challenged this belief (report issued December 2008). It appears that P6 M14 has much higher deuterium uptake in the compressive regions of the pressure tube and the $H_{eq}$ exceeds the solubility limit at both inlet and outlet rolled joint burnish marks.

Although the fuel channel work conducted under COG is considerable, if it continues at its current pace, it will not address the following concerns in time for OPG to make confident predictions of fuel channel pressure tube life in order to optimally plan potential refurbishment activities:

a) Pressure tube material property changes with high $H_{eq}$;
b) Kinetics of deuterium ingress (increasing $H_{eq}$) in the rolled joint region - to project future values and predict when EOL values will be reached; and
c) The appropriateness of the current limits

If it is demonstrated that there remains an adequate margin on material properties with high $H_{eq}$, changing the limits may be justified, thereby increasing confidence that Darlington can operate to 210k EFPH or beyond and that Pickering B can operate to 240k EFPH or beyond.

***Crack Initiation***

Extensive flaw populations in Pickering B were generated in pressure tubes, largely during commissioning due to construction debris entrained in the Primary Heat Transport System (PHTS). Flaws that fail to satisfy the acceptance criteria provided in CSA N285.4-05 must be evaluated for acceptability and the condition must be dispositioned with the regulator. CSA N285.8-05 provides the recognized and accepted means of assessing flaws. One requirement is to demonstrate that crack initiation will not occur from DHC, fatigue and hydrided region overload. Pickering B currently has a number of flaws where crack initiation is predicted. This has resulted in the imposition of thermal cycle limits on operation and a requirement for re-inspection to assure that there has been no crack propagation. Although crack initiation has never been observed, these flaws continue to be monitored with a decreasing number of available cycles due to increasing deuterium concentration in the pressure tubes. Procedures currently used to assess flaws carry a significant degree of conservatism which is becoming increasingly limiting.

Test programs are underway to address the excessive conservatism involving the use of more realistic flaw geometries, $H_{eq}$ and sample conditioning. Initial results have shown much greater resistance to crack initiation in pressure tubes using these conditions. However, it is proceeding at a pace that will not produce the desired results by 2012 as required by OPG to better plan possible refurbishment activities.

A recent attempt to modify the evaluation procedure for fatigue crack initiation was not accepted by the CNSC because there was insufficient data to support the proposed changes. Following this, an 'interim approach' was adopted with a commitment to produce more data in the next few years to support the original request. This would include testing pressure tube material in air and reactor water (to capture any environmental effects).

Additional testing to support changes to all crack initiation mechanism evaluation procedures would increase the operating window (especially for Pickering B) by showing that pressure tubes currently in service have a higher resistance to crack initiation than they are currently given credit for in assessments.

### *Probabilistic Core Assessments and Leak-Before-Break*

CSA N285.8-05 requires that probabilistic core assessments be conducted to demonstrate that the probability of pressure tube rupture remains acceptably low, and that leak-before-break capability remains.

In addition to evaluating detected flaws found during inspections, the condition and acceptability of the pressure tubes in the reactor core as a whole must be evaluated using a Probabilistic Core Assessment (PCA). Among other input information, data from crack initiation experiments and the subsequent evaluation methodologies in the PCAs which impact on the probability of pressure tube rupture are to be evaluated against an acceptance criterion. The current state-of-the-art understanding of crack initiation is not captured in the current PCA code and, for this reason, the results are considered to be conservative. As well, the tool is not qualified to the industry standard of CSA N286.7. This exposes OPG to some regulatory risk.

Leak-before-break refers to the scenario where a through-wall crack in a pressure tube results in a leak into the Annulus Gas System which is detected and subsequent operator actions are taken to place the reactor in the cold and depressurized state prior to reaching the extent of crack propagation when pressure tube would catastrophically fail. Assurance of this capability is becoming increasingly difficult as the pressure tube properties degrade with time, and a change in methodology and/or input parameters can have a significant impact on the eroding margin between what is done at the stations and what needs to be done to demonstrate compliance.

### *Spacer Integrity and PT/CT Contact*

Annulus spacers perform the critical function of maintaining a gap between the pressure tube and calandria tube – to assure that contact between these components cannot occur. This contact led to the catastrophic failure of channel G16 of Pickering Unit 2 in 1983. As such, spacer integrity must be demonstrated over the full operating life of the reactor.

The spacers used in Darlington are a tight-fitting design made from Inconel X-750 design which is meant to remain in its as-left position for the duration of the operating life. Recent OPEX from the recent removal of the pressure tube and spacers from channel O18 in Darlington Unit 2 has indicated that the structural integrity of this spacer design may not be sufficient to achieve the current nominal operating life of 210k EFPH. This is because the removed spacers arrived at AECL-CRL (Chalk River Laboratories) in several pieces and testing indicated that some material properties had degraded. Although the flasking and transportation to AECL-CRL may have led to the ultimate failure of these spacers, their degraded properties are due to operation. It is unknown at this time whether the degradation in properties of spacers in service at Darlington has saturated or if degradation will continue. This issue is one that could result in premature shutdown of Darlington units, since failure of a spacer leading to pressure tube-calandria tube (PT-CT) contact in the outlet region of almost any pressure tube in Darlington would result in hydride blister formation and subsequent pressure tube rupture.

Although the material properties of the loose-fitting Zr-Nb-Cu spacers in Pickering B are considered to be adequate for a 240k EFPH pressure tube life, the root cause investigation of the failed calandria tube in Pickering Unit 7 channel A13 revealed significant spacer wear as well as wear on the adjacent pressure tube and calandria tube surfaces. This calls into question whether the spacers in Pickering B are capable of maintaining a PT-CT gap during a 240k EFPH pressure tube. The root cause investigation team has produced an interim report, but the current funding source will not support additional activities to determine the root cause of spacer wear, the extent/severity of spacer is in OPG reactors, or the impact of worn spacers on PT-CT contact predictions.

In addition, there is currently no program to periodically assess spacer integrity as they can only be examined when a fuel channel pressure tube is replaced. Moreover, they aren't part of the normal surveillance activities associated with fuel channel replacement. Therefore, a spacer program is needed to assure structural integrity over the full unit operating life. Elements of this program include: a comprehensive literature survey to determine the credible degradation mechanisms and subsequent assessment methods/procedure and acceptance criteria for the results.

## 3/ ALTERNATIVES AND ECONOMIC ANALYSIS

| $ Millions | Timing | Base Case | | | Recommendation | | |
|---|---|---|---|---|---|---|---|
| | | DNGS | PNGSB | Total | DNGS | PNGSB | Total |
| EFPH 000's | | 187K EFPH | 210K EFPH | | 210K EFPH | 240 EFPH | |
| Revenue | 2009 to EOL | 120,551 | 6,513 | 127,064 | 131,831 | 12,198 | 144,029 |
| OM&A Operations | 2009 to EOL | (54,964) | (4,341) | (59,305) | (59,321) | (7,672) | (66,993) |
| OM&A Project | 2009 to EOL | 0 | 0 | 0 | (12) | (12) | (25) |
| Refurb (Capital) | 2009 to EOL | (5,827) | 0 | (5,827) | (6,051) | 0 | (6,051) |
| Present Value (PV) | 2009 to EOL | 9,053 | 1,261 | 10,314 | 10,321 | 2,191 | 12,512 |
| **Net Present Value (NPV)** | | **N/A** | **N/A** | **N/A** | **1,268** | **930** | **2,198** |

### Base Case: Not Recommended - Continue with current COG R&D program to support Fuel Channel FFS (Do nothing)

At the pace with which fuel channel R&D is proceeding under COG, the results of testing and associated analyses will be not be completed in time to demonstrate high confidence (>70%) in fitness-for-service beyond 187k EFPH for Darlington and beyond 210k EFPH for Pickering B. This could result in Darlington units reaching their end-of-life as early as 187k EFPH with the possible refurbishment advanced from 2016 to 2014 - at substantial cost. For Pickering B, support for the technical basis for operation of fuel channel components to 240k EFPH will likely not have the required confidence by 2012 if the work is not accelerated.

### Alt. 1: Recommended - Follow proposed plan to acquire appropriate information for 2012 (Do this)

Completing the proposed experimental and analysis work within the required timeframe in conjunction with executing LCM planned inspections and maintenance will demonstrate whether there is high confidence (>70%) that Darlington units can operate to 201k EFPH or beyond and Pickering B can operate to 240k EFPH or beyond – allowing possible refurbishment activities to be planned effectively at Darlington. The operation of Pickering B to 240k EFPH would realize greater economic value from these units.

### Alt. 2: Not Recommended - Delay proposed work by one year

If the proposed work is delayed by one year, the required results to support high confidence nominal EOL predictions will not be realized until 2013. This is one year later than the target date and only one year before possible Darlington refurbishments would have to begin if operation beyond 187k EFPH cannot be supported with high confidence (>70%), leaving no adequate lead time to plan the refurbishment.

*Note: Regulatory conditions require that at least some of this work is funded and initiated in the short term (i.e. fatigue crack initiation experiments).*

### Alt. 3: Not Recommended - Conduct some of the work proposed (Do less)

This alternative is a 20% cost reduction in scope over the recommended Alternative 1 where the work with the least impact on satisfying the project objective was removed from the scope. It is anticipated that the impact of reducing the scope would result in a reduction to the confidence to below 70% in EOL predictions required to support operation of Darlington to 210k EFPH and Pickering B to 240k EFPH.

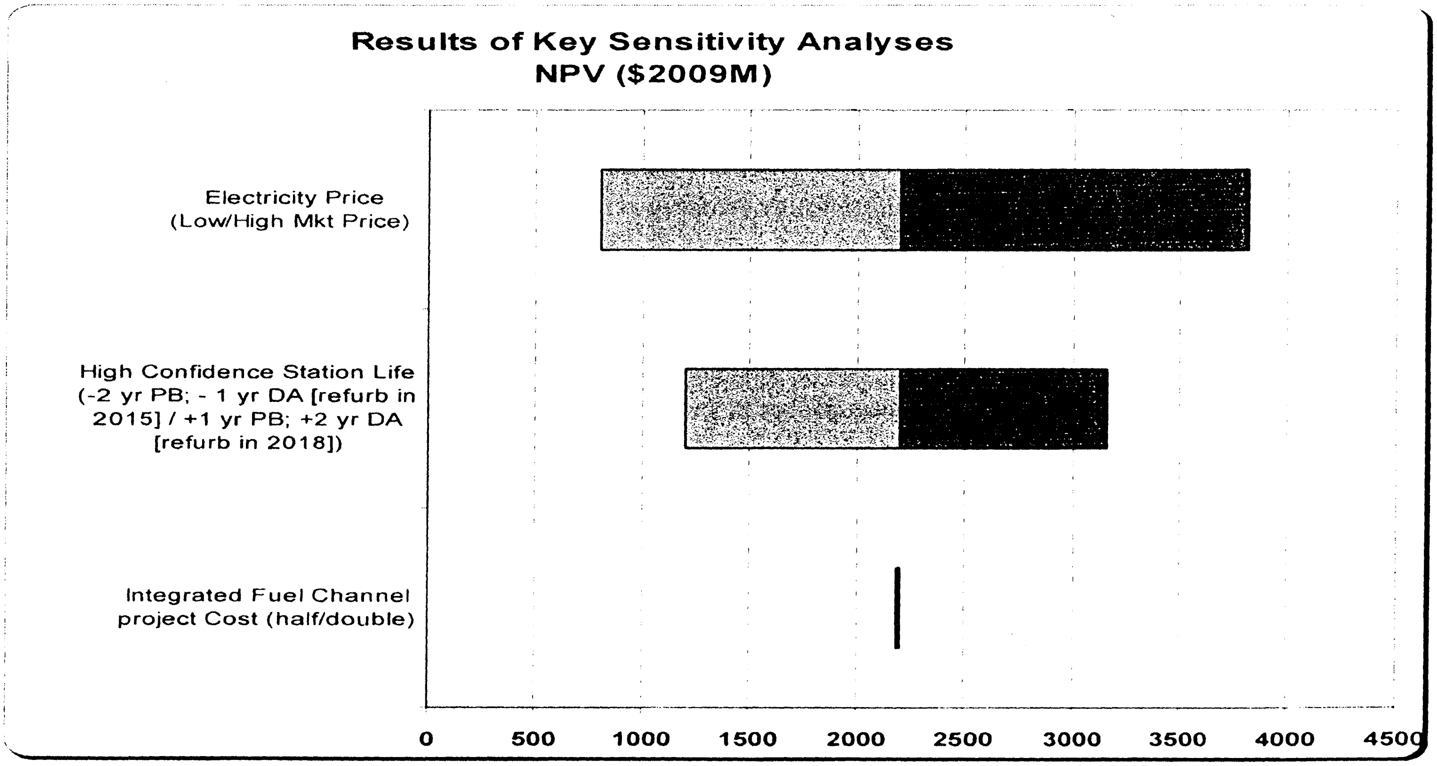
This alternative is not recommended based on supporting high confidence (>70%) projections of operating Darlington units to 210k EFPH or beyond (from 187k EFPH) and Pickering B units to 240k EFPH or beyond (from 210k EFPH), the calculated value of this work exceeds the estimated cost and any reductions to the scope could impose an unacceptably large risk on the project and impede achievement of objectives.

### Alt 4: Not Recommended - Request regulatory relief on life limiting issues

In the area of fuel channel fitness-for-service, several submissions to revise the fitness-for-service methodologies (or inputs tc these methodologies) have not been completely accepted by the regulator and 'interim approaches' have been utilized whicr include commitments to conduct additional work to justify the original submissions. By requesting relief in areas wherε commitments have been given (including some cases with formal plans) to justify previous submissions, the regulator may lose confidence in OPG since the regulator may already consider the 'interim approaches' to be a form of relief. Moreover, technical experts in the industry share most of the concerns of the regulator, and it would be prudent to get the appropriate answers rather than requesting relief.

### Alt. 5: Not Recommended - Accelerate program further to get answers in 2011 (Do more)

Although having answers sooner (i.e. 2011) would be very beneficial, it is unlikely that additional funds would make this possible. The current limitation in this work is resources – specifically technical experts, technicians and facilities. Even if the funding could be made available immediately, facilities similar to those at AECL-CRL, capable of conducting work on pressure tubes, cannot be built in the time required.



Results of the economic assessment were tested for sensitivity to key inputs such as (i) assumed electricity price, (ii) length of additonal station life achieved, and (iii) integrated fuel channel project costs, and indicate the following:
(i) The value is extremely sensitive to the assumed electricity price. In a high price regime, the value would be $3.8 B and in a low price regime, the value would be $800 M. A low price regime would result from low electricity demand and low gas prices, such as during a prolonged economic slowdown or high conservation.
(ii) The value is sensitive to the station life that can be achieved with high confidence. If Pickering B units achieve only 225k EFPH and Darlington units achieve only 200k EFPH with Darlington refurbishment starting in 2015, then the value would be $1.2 B. If the Pickering B units achieve 248k EFPH and the Darlington units achieve 225k EFPH with Darlington refurbishment starting in 2018, then the value would be $3.1 B.
(iii) The value is insensitive to project costs even if they are doubled.

## 4/ THE PROPOSAL

This Partial Release is to start critical path/long lead time work required to increase confidence that Darlington units will operate to 210k EFPH or beyond and that Pickering B units will operate to 240k EFPH or beyond. It is intended that this program will provide the results by 2012 thereby allowing development of the appropriate bases to support fitness-for-service. The partial release will fund the project work to be conducted until the end of 2010.

The scope of work for the complete project includes activities to address:

1. Deuterium ingress and its impact on material properties
2. Crack initiation
3. Leak Before Break and Core Assessments
4. Spacer Integrity and PT/CT contact

Tasks under each category are designed to create a more comprehensive, overall understanding of fuel channel degradation and fitness-for-service limits. This work will support regulatory submissions to modify fitness-for-service methodologies, acceptance criteria, etc. related to fuel channels. This would essentially shift the fitness-for-service limits and (ideally) support the operation of Pickering B units to 240k EFPH or beyond and the operation of Darlington to 210k EFPH or beyond.

The following work includes the total current project work scope to be conducted over the next 3 years as a joint project between OPG and Bruce Power with cost sharing at a ratio of 5.5:3.5 (OPG:BP).

**Deuterium Ingress and its Impact on Material Properties**
A method will be developed to add hydrogen/deuterium to ex-service pressure tube material in a manner which does not affect the irradiation damage*. After this technique is qualified, tests to determine the fracture toughness at proposed end-of-life conditions will be conducted as proposed in the COG Joint Project 4299. Since it is anticipated that the engineering/qualification of a new method/technique will require approximately one year of effort and to mitigate the risk of a new technique not being capable of achieving the desired results, a parallel task involving the current technique will be pursued with a plan for its implementation as a non-ideal solution. Other, supplementary fracture toughness tests on both ex-service and un-irradiated pressure tube material will be conducted to support the development of fracture toughness curves at end-of-life $H_{eq}$ levels.

Other activities to support deuterium ingress projections will be conducted including: developing detailed requirements for rolled joint $H_{eq}$ model to ensure that the modification of current code addresses concerns over the lack of predictability; updating the body-of-tube deuterium ingress model to improve the accuracy of long term predictions; and using existing and new data/models to calculate the time reach end-of-life $H_{eq}$ values for all units.

** This work currently carries the greatest degree of uncertainty/risk because the vendor(s) have not stated conclusively whether or not they can conduct some of the proposed work in their hot cells. Because of this, a parallel path of doing the engineering and initial qualification in other hot cell facility will be followed.*

**Spacer Integrity and PT/CT contact**
To address concerns over tight-fitting (Darlington) spacer integrity, the major scope of work includes: determination of the mechanism of degradation of I-X750 spacer material, development of a comprehensive program of condition monitoring including evaluation methods and acceptance criteria for examination of ex-service spacers and pursuing the implementation of PT-CT gap measurements to assure spacer integrity and capability to maintain an appropriate gap. As well, an experimental program to irradiate I-X750 may be warranted to determine the rate of degradation in early life for extrapolation and projection to late life operation.

To address the concerns over loose-fitting (Pickering B) spacer wear, the major scope of work includes: completing the root cause investigation for P7 A13, determination of the impact of spacer wear on PT-CT predictions, and examination of other available ex-service spacers to determine the possible extent of spacer wear in OPG reactors.

**Crack initiation**
Tests using more realistic sample geometries and conditioning cycles will be conducted to quantify increased crack initiation resistance. This will allow flaws in Pickering to pass fitness-for-service evaluations in the future as well as support Probabilistic Core Assessments.

The work includes: quantifying the positive benefit of reduced pressure shut down on crack initiation, increasing the variability and $H_{eq}$ validity range on the non-ratcheting factor, determining the effect of having surface flaws and angled flaws versus full-length/axial flaws. Preliminary assessments of this type of work has indicated that pressure tubes are more resistant to crack initiation than current methodologies credit and, with the data to be acquired from these tests, the technical basis to modify fitness-for-service methodologies can be made.

Fatigue crack initiation experiments will be conducted in air on both ex-service material and un-irradiated material, as well as in a reactor water environment on un-irradiated material to support regulatory commitments to use the current 'interim approach' and make subsequent changes to the evaluation procedures. This will enable Pickering B to pass flaw evaluations and remove cycle limitations imposed by fatigue crack initiation.

**Probabilistic Core Assessments and Leak-Before-Break**
The Probabilistic Core Assessment tool will be updated to reflect the current understanding of fuel channel degradation, as determined by other parts of this project, to offer a more realistic assessment of reactor core integrity. In addition, the tool will be qualified to the requirements of CSA N286.7 as an Industry Standard Tool (IST).

A new approach to the leak-before-break methodology will be explored which follows what is done in US plants to move away from the overly conservative treatment currently used. This will enable increased margin to be demonstrated in assessments. This increased margin will allow further material degradation and equipment availability issues to be accommodated more easily.

The project work will also include ensuring that condition monitoring prescribed in the OPG Fuel Channel Aging and Life Cycle Management Strategy and Plan is executed. The resultant data is essential to determine when fitness-for-service limits will be reached. In addition, it is essential that experimental results be analyzed and technical basis documents developed to support improved methodologies meeting technical and regulatory requirements.

## 5/ QUALITATIVE FACTORS

This work is intended to be part of an industry-wide initiative to gain greater certainty on the fitness-for-service limits for fuel channels. If this is executed as a COG Joint Project, it gives Bruce Power important information concerning the timing of possible OPG refurbishment activities. This will help the industry to optimize refurbishment plans, and may reduce the strain on resources to conduct refurbishment of many units in parallel.

Even if it is determined that the current base case is accurate, and refurbishment activities must be brought forward in time from 2016 to 2014, this will be much more advantageous than unplanned shutdown of the units.

This work is part of a comprehensive Fuel Channel Life Management Plan which has been developed to drive to higher levels of confidence in longer pressure tube lives for the OPG nuclear units. Achieving higher levels of confidence has many benefits which are not easy to quantify including providing enhanced flexibility to OPG to:

(i) Manage the lead time constraints, and other preparatory issues (e.g. resource constraints, long lead time material, project mobilization) associated with the Pickering B refurbishment, should it proceed;
(ii) Manage the overall refurbishment schedule for the nuclear units, particularly the uncertainty around the refurbishment schedule for the Darlington units given current uncertainties in unit end-of-life dates, should it proceed;
(iii) Manage the uncertainties created by any potential delays to new nuclear in-service dates; and
(iv) Manage the potential significant capital and resource requirements and financial sustainability of OPG associated with multiple simultaneous refurbishments and new build nuclear campaigns;
(v) Manage regulatory risks associated with fitness-for-service limits.

## 6/ RISKS (see Attachment D for details)

| Low = 1 to 3 | Medium = 4 to 9 | High = 10 to 25 |
|---|---|---|

| | | Impact | | | | |
|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 |
| Probability | 5 | 5 | 10 | 15 | 20 | 25 |
| | 4 | 4 | 8 | 12 | 16 | 20 |
| | 3 | 3 | 6 | 9 | 12 | 15 |
| | 2 | 2 | 4 | 6 | 8 | 10 |
| | 1 | 1 | 2 | 3 | 4 | 5 |

| Risk Description | Mitigating Activities | Before Mitigation | | | | | | | | | After Mitigation | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Probability x Impact | | | | | | | | | Probability x Impact | | | | | | | | |
| | | Finance | Schedule | Quality | Corporate Reputation | Regulatory | Health & Safety | Environment | Nuclear Safety | Risk Rating (1 to 25) | Finance | Schedule | Quality | Corporate Reputation | Regulatory | Health & Safety | Environment | Nuclear Safety | Risk Rating (1 to 25) |
| Resources unavailable to do the work in the required timeframe | Get estimates and resource commitments from vendors before full release.<br>Close collaboration with the COG fuel channel work program to ensure optimum utilization of existing resources.<br>Pursue alternate facility for engineering work associated with new hydrogen addition technique.<br>Spread work over multiple facilities with ability to scale up work at alternate facility. | | 12 | | | | | | | **12** | | 8 | | | | | | | **8** |
| Results indicate degraded properties which impact on continued operations (including other stations) | Pre-establish performance criteria and evaluate impact<br>Monitor results progressively with hold points to ensure that expected performance attained and potential impact.<br>Establish more comprehensive fitness-for-service assessments | 10 | | | 10 | 10 | | | | **10** | 4 | | | 4 | 4 | | | | **4** |
| Funding not available in time to complete work | Establish schedule based on release of funds and accelerate work if necessary and possible | | 15 | | | | | | | **15** | | 8 | | | | | | | **8** |
| Other EOL work not funded - negating large benefit of this work | Hold challenge meeting with OPG and industry partners to minimize probability of unfunded work. | | 10 | | | | | | | **10** | | 5 | | | | | | | **5** |
| Regulator disallows use of the results in determination of end-of-life limits. | Obtain buy-in from regulator on project plan and approach to be undertaken | | | | 6 | 12 | | | | **12** | | | | 2 | 3 | | | | **3** |

| Low = 1 to 3 | Medium = 4 to 9 | High = 10 to 25 |
|---|---|---|

| | | Impact | | | | |
|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 |
| Probability | 5 | 5 | 10 | 15 | 20 | 25 |
| | 4 | 4 | 8 | 12 | 16 | 20 |
| | 3 | 3 | 6 | 9 | 12 | 15 |
| | 2 | 2 | 4 | 6 | 8 | 10 |
| | 1 | 1 | 2 | 3 | 4 | 5 |

| | | Probability x Impact | | | | | | | | | Probability x Impact | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Finance | Schedule | Quality | Corporate Reputation | Regulatory | Health & Safety | Environment | Nuclear Safety | Risk Rating (1 to 25) | Finance | Schedule | Quality | Corporate Reputation | Regulatory | Health & Safety | Environment | Nuclear Safety | Risk Rating (1 to 25) |
| **Risk Description** | **Mitigating Activities** | **Before Mitigation** | | | | | | | | | **After Mitigation** | | | | | | | | |
| | Keep the regulator informed of results as project progresses. | | | | | | | | | | | | | | | | | | |
| Unable to hydride material to appropriate levels with new technique | Parallel work to use current technique to get necessary data | | 8 | | | | | | | **8** | | 4 | | | | | | | **8** |
| FC LCM planned work not completed during outages to obtain necessary data | Ensure stations are aware of the impact of not conducting inspection work in LCM | | | | 12 | 12 | | | | **12** | | | | 4 | 4 | | | | **4** |
| Results from inspections show increased D-uptake rate in RJ | Use this work as basis, if possible, for increasing EOL limits | 10 | | | | 8 | | | | **10** | 6 | | | | 4 | | | | **6** |
| Vendor resists using new hydriding technique in hot cells | Pursue alternate facility for engineering work associated with new hydriding technique | | 9 | | | | | | | **9** | | 4 | | | | | | | **4** |
| Irradiated spacer properties indicate that properties are continuing to degrade | More comprehensive assessments will be conducted to demonstrate fitness-for-service | 9 | | | | | 12 | | | **12** | 6 | | | | 6 | | | | **6** |
| Unanticipated event causes hot cell unavailability | Allow enough lead time in work to absorb some delay | | 8 | | | | | | | **8** | | 4 | | | | | | | **4** |
| Bruce Power and/or Atomic Energy of Canada chooses not to co-fund this work in subsequent years | Contingency added in out years to accommodate any reductions in funding by other participants<br>Additional OPG funding may be necessary to complete defined scope | 8 | | | | 8 | | | | **8** | 4 | | | | 4 | | | | **4** |

## 7/ POST IMPLEMENTATION REVIEW PLAN

| Type of PIR: | Targeted Final AFS Date: | Targeted PIR Approval Date: | PIR Responsibility (Sponsor Title) |
|---|---|---|---|
| Simplified | Dec 2013 | Jun 2014 | VP, Science and Technology Development Division |

| | Measurable Parameter | Current Baseline | Targeted Result | How will it be measured? | Who will measure it? (person / group) |
|---|---|---|---|---|---|
| 1. | Results received from experiments and analyses | 2016 assuming COG funding remains at current level, and appropriate task funded. | August 2012 | Date final results are received to support next parameter | Manager, MCED |
| 2. | Submission of technical basis to modify FFS to regulator | 2016 based on appropriate results (see Item 1) | December 2012 | Date of submission of documents to the regulator | Project Sponsor |
| 3. | High confidence EOL predictions for Pickering B Fuel Channels | 210K EFPH | 240K EFPH | Fuel Channel experts concur with high confidence | Manager, MCED |
| 4. | High confidence EOL predictions for Darlington Fuel Channels | 187K EFPH | 210K EFPH | Fuel Channel experts concur with high confidence | Manager, MCED |

## Appendix "A" Glossary (acronyms, codes, technical terms)

EOL – End-of-life – Based on design life of 210k EFPH
$H_{eq}$ – equivalent hydrogen concentration if all deuterium [D] were replaced with protium [H] ($H_{eq}$ = [H] + [D]/2)
D-ingress – with hot operation, deuterium enters pressure tube material
Hydriding – the process of adding hydrogen (deuterium or protium) to pressure tube material to simulate later life conditions
RJ – rolled joint between the pressure tube and end fitting
PT – Pressure tube
CT – Calandria tube
PHTS – Primary Heat Transport System
COG – CANDU Owners Group
PCA – Probabilistic Core Assessment, used to evaluate degradation of all fuel channels based on established methodologies and inspection results
CNSC – Canadian Nuclear Safety Commission, Canadian regulator under the Nuclear Safety and Control Act
AECL – Atomic Energy of Canada Limited
AECL–CRL – Chalk River Laboratories of AECL where ex-service fuel channel examination and testing is typically conducted

## Appendix "B" Project Funding History

| $ 000's |  | All Existing and Planned Releases (incl contingency) Cumulative Values |  |  |  |  |  |  |  |  |  |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Release Type | Month | Year | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | Later | Total |
| Partial | Jun | 2009 | 2,533 | 9,728 |  |  |  |  |  |  | 12,261 |
| Full | Aug | 2010 |  |  | 7,741 | 4,009 | 908 |  |  |  | 12,658 |
|  |  |  |  |  |  |  |  |  |  |  | 0 |
|  |  |  |  |  |  |  |  |  |  |  | 0 |
|  |  |  |  |  |  |  |  |  |  |  | 0 |
|  |  |  |  |  |  |  |  |  |  |  | 0 |

**Comments:**

## Appendix "C" Financial Model – Assumptions

### Financial Assumptions:

| | | | | | |
|---|---|---|---|---|---|
| Discount Rate | 7% | Cost Escalation (yr) | 2% | SR & D Opportunity | See Comments |
| Progress Payments | N/A | Foreign Currency | ??? | Retainer Fee | ??? |
| Income Tax Rate | | PST | ??? | Interest Rate (Capital) | ??? |
| Depreciation Rate (Capital) | N/A | Leasing | ??? | Indexed Priced Contract | ??? |

**Comments:**
SR&D opportunity to be explored. It is likely that at least some of this work would qualify.

### Project Cost Estimate:

| | | | | | |
|---|---|---|---|---|---|
| Design Complete | N/A | Quality of Estimate | Budget + 30% to - 15% | 3rd Party Estimate | N/A |
| Reviewed by Sponsor | Yes | OPEX used | N/A | Lessons Learned | none available |
| Similar Projects | Yes | Budgetary Quote(s) | No | First Unit Actual Used | Not unitized |
| Cost Sharing | TBD | Contracts in place | Some in place | Competitive Bid | None requested |
| Fixed Price Contract | | Fee for Service | N/A | Firm Vendor Proposal | No |

**Comments**:
Partner through COG and the CANDU industry will be sought to reduce costs to OPG.

### Rationale for Cost Classification:

N/A

### Generation Plan Assumptions:

| Station | Unit | EOL | | MW | Capacity | Planned Outages for Project Work (eg P1071) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Pickering A | 1 | N/A | N/A | | N/A | | | | | | | |
| | 4 | N/A | N/A | | | | | | | | | |
| Pickering B | 5 | N/A | N/A | N/A | N/A | | | | | | | |
| | 6 | N/A | N/A | | | | | | | | | |
| | 7 | N/A | N/A | | | | | | | | | |
| | 8 | N/A | N/A | | | | | | | | | |
| Darlington | 1 | Jun | 2018 | 935 | 88% | | | | | | | |
| | 2 | Sep | 2016 | | | | | | | | | |
| | 3 | Mar | 2020 | | | | | | | | | |
| | 4 | Dec | 2021 | | | | | | | | | |

**Comments:**
N/A

## Fuel Channel Life Management 10 - 62444
## Partial Release Business Case Summary N - BCS - 31100 - 10001 – R000

**Attachment "A"** **Project Cost Summary**

| | $000's<br>OM&A | LTD<br>2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Scores Basis | Project Mgmnt & Support | 302 | 416 | 416 | 416 | 208 | | | | 1,758 |
| | Engineering | 300 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Procurement | | | | | | | | | - |
| | Construction | | | | | | | | | - |
| | Other | | | | | | | | | - |
| | Project R&D | 1,866 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Issue Management System | 65 | | | | | | | | 65 |
| | | | | | | | | | | - |
| | | | | | | | | | | - |
| | Interest (Capital Project Only) | | | | | | | | | - |
| | **Project Costs** | **2,533** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | General Contingency | - | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Specific Contingency | | | | | | | | | - |
| | **Project Costs** | **2,533** | **9,728** | **7,741** | **4,010** | **908** | **-** | **-** | **-** | **24,920** |
| Cash | **Adjust to Cash Basis +/-** | | | | | | | | - | - |
| | **Project Costs** | **2,533** | **9,728** | **7,741** | **4,010** | **908** | **-** | **-** | **-** | **24,920** |
| Funding | **Currently Released** | | | | | | | | | - |
| | **This Release** | 2,533 | 9,728 | | | | | | | 12,261 |
| | **Future Release** | | | 7,741 | 4,010 | 908 | | | - | 12,659 |
| | **Project Funding** | **2,533** | **9,728** | **7,741** | **4,010** | **908** | **-** | **-** | **-** | **24,920** |

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Budget | | | | | | | | | | - |
| | **Variance to Business Plan** | **2,533** | **7,553** | **6,336** | **3,351** | **783** | **-** | **-** | **-** | **20,556** |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Other | Removal Costs included above | | | | | | | | | - |
| | Inventory to be written off | | | | | | | | | - |
| | Spare Parts in Inventory | | | | | | | | | - |

The estimated variance(s) to the **2009-2013 Business Plan** will be addressed through the portfolio management process.
A PCRAF **will be approved by Oct 2009.**

Reviewed By: June 11/09
Norman Webb
Project Manager
Date:

Approved By: 2009-06-17
Don Wilson
Strat IV Manager
Date:

## Attachment "B" Milestones and In Service Declarations

## Key Milestones

| Completion Date | | | Description |
|---|---|---|---|
| Day | Mth | Yr | |
| 31 | May | 2009 | List of prioritized work with cost and schedule estimates developed |
| 30 | June | 2009 | BCS approval from AISC |
| 31 | Aug | 2009 | Funding secured for Long Lead items from Partial Release |
| 31 | Aug | 2009 | Issue RFP/RFQs for long lead work identified in plan |
| 15 | Sep | 2009 | Kick-off Meeting |
| 30 | Oct | 2009 | PEP issued for use |
| 30 | Jun | 2010 | BCS finalized with more accurate scope and cost estimates |
| 31 | Aug | 2010 | Approval of funding for project (BCS approved) |
| 31 | Aug | 2010 | Issue RFP/RFQs for balance of work identified in plan |
| 31 | Aug | 2012 | Results obtained from analysis and experiments |
| 31 | Dec | 2012 | Regulatory acceptance of the fitness-for-service basis for continued operation |
| | | | |
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A Project Execution Plan (PEP) **will be approved by Oct 2009**

## In Service Declarations: (Capital Only)

| Month | Year | Description | $ 000's | % |
|---|---|---|---|---|
| | | | | |
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## Attachment "C"

## Risk Probabilities Chart

| **Likelihood** | Improbable | Unlikely | Possible | Likely | Probable |
|---|---|---|---|---|---|
| **Probability** | <= 1 in 1000 | About 1 in 100 | About 1 in 10 | About 1 in 5 | >= 3 in 4 |
| **Rank** | 1 | 2 | 3 | 4 | 5 |

## Risk Impact Chart

| **Impact Rating** | **Financial** | **Project Schedule (12 months)** | **Quality** | **Corporate Reputation** | **Regulatory / Legal** | **Health & Safety** | **Environment** | **Nuclear Safety** |
|---|---|---|---|---|---|---|---|---|
| 5 | >80% of Total Project $ | > 90 day delay | Significant, unacceptable non-conformance requiring extensive rework | National and international adverse coverage or impacts | Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges **OR** Potential loss of operating licenses | Potential for fatality(s) | Spill or release causing immediate and extended impact with off-site impacts, e.g.:<br>Clean-up costs > $15M<br>Cat. A spill (>55 pts) | Loss or serious degradation of a safety system |
| 4 | 30% - 80% of Total Project $ | 30 - 90 day delay | Unacceptable non-conformance requiring some rework, but not major | Long-term local or national impact | Legislative non-compliance with potential for fines, charges, and damages **OR** Major degradation of reputation with regulatory bodies | Potential for life-threatening critical injury or permanent total disability, including occupational disease | Exceedances resulting in charges or Director's Order<br>Cat. A spill (45 - 55 pts)<br>Public complaints with OPG implications<br>Explosion and/or major fire | Reduced effectiveness of a safety system |
| 3 | 15% - 30% of Total Project $ | 10 - 30 day delay | Non-conformance bordering design tolerances, potential to require rework | Major local impact or minor national impact.<br>Minor local damage | Systematic non-compliance with potential for fines<br>OR<br>Potential to cause strained relationship with regulator, increased surveillance and/or regulations | Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature | Cat. B spills<br>Emission in exceedance of regulatory or legal limits<br>Field orders or AMP's<br>Public complaints with OPG implications<br>Danger to health, life, or property | Reduced effectiveness of redundant safety system components |
| 2 | 5% - 15% of Total Project $ | 3 - 10 day delay | Acceptable non-conformance, within design tolerances, no rework required | Complaints from local officials / politicians | Systematic non-compliance with impacts to project schedule<br>OR<br>Possibility of regulatory / legal implications | Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker. | Cat. C spills - reportable<br>Administrative infractions<br>Public Complaints with plant level implications | Impact on a safety support or safety related system |
| 1 | <5% of Total Project $ | < 3 day delay | Minimal impact on quality<br>Routine non-conformance, can be easily dispositioned | Complaints from local public | Isolated non-compliance<br>OR<br>Routine approval / notification | No medical attention beyond first aid, no impairment to worker or complete recovery of worker. | Administrative, non-reportable events<br>Cat. C spills non-reportable and spills resulting from Acts of God | |

## Business Case Summary

# Fuel Channel Life Management Project 10 - 62444 (OM&A)
# & Spacer Retrieval Tool Project 28 - 66567 (Capital)
# Partial Release Business Case Summary N - BCS - 31100 - 10006 - R000

| Name / Title / Phone | Location | Action | Signature | Date |
|---|---|---|---|---|
| EXECUTING ORGANIZATION - FCLMP | | | | |
| Imtiaz Malek<br>Director, Fuel Channel Life Management Project | P82-6 | Review BCS | | July 4, 2011 |
| Mark Elliot<br>SVP, Nuclear Engineering & Chief Nuclear Engineer | P82-5 | Review BCS | | 2011/07/12. |
| PROJECT SPONSORS | | | | |
| Wayne Robbins<br>Chief Nuclear Officer | P82-6 | Submit BCS | | 2011-07-20 |
| Albert Sweetnam<br>EVP, Nuclear Projects | H17-G25 | Submit BCS | | 20 July 11 |
| BCS APPROVAL | | | | |
| Don Power<br>Vice President, Corporate Investment & Asset Planning | H07-G05 | Approve BCS | | Aug 3/11 |
| Donn Hanbidge<br>SVP & Chief Financial Officer | H19-F27 | Approve BCS | | Aug 12/11 |
| Tom Mitchell<br>President & Chief Executive Officer | H19-A24 | Approve BCS | | |
| Carolyn Sicard<br>Nuclear Investment Management<br>702-4082 | P82-3B6.2 | Return for Distribution | | |
| Jamie Lawrie<br>Director, Investment Management<br>Nuclear Finance | P82-3 | Review BCS | | July 22/2011 |
| Randy Leavitt<br>VP, Nuclear Finance | P82-3 | Review BCS | | July 22, 2011. |

# Fuel Channel Life Management Project 10 - 62444 (OM&A)
# & Spacer Retrieval Tool Project 28 - 66567 (Capital)
# Partial Release Business Case Summary N - BCS - 31100 - 10006 - R000

## 1/ RECOMMENDATION:

We recommend a third **Partial** Release of an **additional $18.6** Million **Capital and OM&A** (including a contingency of [redacted] Million) to fund the following work:

1) $16.4 Million **OM&A** to fund **additional research & development (R&D) activities, plus new scope of oversight of supporting activities and increased regulatory interface activities** for the Fuel Channel Life Management Project (10-62444).
2) $2.2 Million **Capital** to fund **design, procurement, and commissioning activities** for the Spacer Retrieval Tool Project (28-66567), which started in 2011.

Approval of this request will bring the total funding released to date to **$37.5** Million, including a contingency of [redacted]. This work is jointly funding by OPG and industry partners, and only OPG's share of the project costs is presented in this business case. This release will fund work activities through to the end of 2012. R&D activities will be completed and a high confidence statement of the service life of pressure tubes at Darlington and Pickering B will be made at the end of 2012, as per the original schedule.

The OM&A project completion date has been extended to June 30, 2015 to accommodate the **new** additional scope of interfacing with the Regulator, providing licensing support, incorporation of R&D results into business and generation plans, as well as project close out activities.

The total project is estimated to cost **$43.1** Million. This represents an overall increase of $12.9 Million for the OM&A work with the breakdown as below:

a) $5.0 Million for new funding to allow OPG to enter into negotiations with Bruce Power to obtain critical spacer degradation data for Darlington FFS (Fitness-for-Service) demonstration through a Bruce Power SFCR project in 2012.
b) $4.5 Million for the added R&D to obtain CNSC concurrence based on 18 technical submissions per agreed CNSC Protocol.
c) $3.4 Million for added new scope to oversee supporting projects (e.g. Gap and Spacer Retrieval Tooling), supporting activities, and to confirm integration of R&D work into surveillance programs.

The final release of the remaining funding on this estimate will be requested in August 2012.

The Business Objectives of these **Sustaining** projects are:

***10-62444 Fuel Channel Life Management Project (OM&A):***
OPG plans to refurbish the Darlington units starting in October 2016. Following this schedule, the last two units to be refurbished will reach or exceed their original planned life of 210k EFPH (Unit 3 in 2019; Unit 4 in 2021). However, due to Darlington's higher operating temperatures and pressure, OPG can only demonstrate with high confidence that the Darlington units can operate to 187k EFPH using current available methodologies. The recently observed new Inconel X-750 spacer degradation mechanism (embrittlement due to nickel transmutation under irradiation) may threaten current operations. Thus, critical information is required from the COG R&D project. OPG will work with Bruce Power to establish the material property degradation rate sooner by using spacers retrieved from a Bruce Unit in 2012 in addition to spacers retrieved from Darlington in 2013.

Pickering B units are not to be refurbished. However, to manage the power supply during the Darlington Refurbishment project, OPG plans to operate the Pickering B units to mid 2020 (~247k EFPH). High confidence that these units will achieve this new planned life needs to be demonstrated prior to the final business planning decision, to be made at the end of 2012.

To demonstrate that both Darlington and Pickering B will reach these operational targets, research in the following technical areas are underway:

1. Deuterium Ingress and its Impact on Material Properties
2. Spacer Integrity and Pressure Tube - Calandria Tube (PT-CT) Contact

3. Crack Initiation
4. Probabilistic Core Assessments (PCA) and Leak-Before-Break (LBB)

There are 2 critical objectives for the short term R&D work:

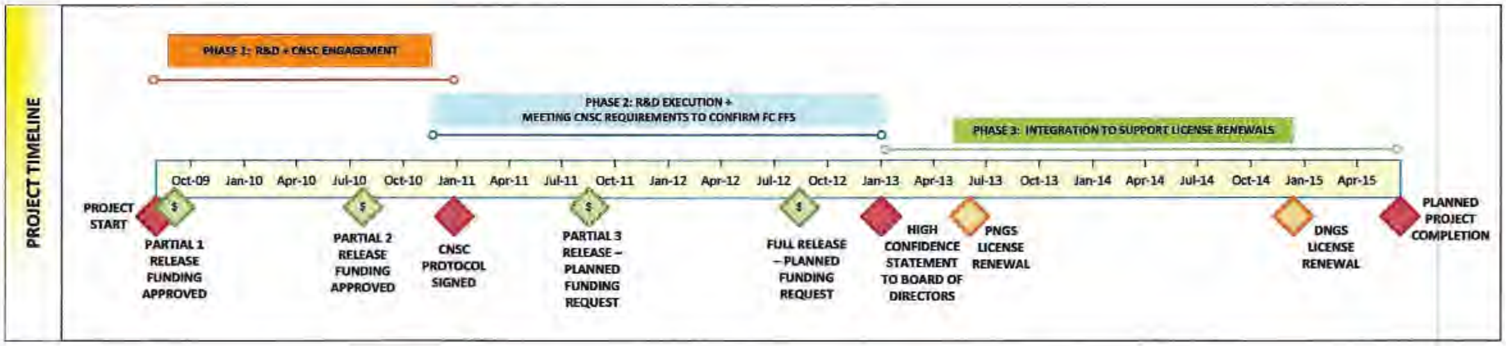
1. Enable a high confidence statement of the targeted service life of Pickering and Darlington fuel channels to be made to the Board of Directors by the end of 2012 in order to make business decisions on the continued operations of Pickering B and the refurbishment schedule for Darlington.
2. Obtain Regulator acceptance of OPG initiatives to operate Pickering B to 2020 and to provide Darlington Refurbishment schedule flexibility. The requirements for the two initiatives, specific to fuel channel technical issues, have been agreed upon and documented in N-CORR-00531-05133 ("the CNSC Protocol").

To ensure success of the two initiatives, post R&D activities need to be managed and transitioned into the base organization. This includes the following activities:

a. Manage regulatory submissions for the application of new or improved methodologies developed from the R&D programs. These submissions are required seperately for Pickering B and Darlington.
b. Manage outstanding CNSC follow-up requirements, such as additional confirmatory R&D work and new inspection requirements to be integrated into life cycle management plans (LCMPs).
c. Develop a long term tight-fitting spacer surveillance and management plan for Darlington.
d. Assist in the license renewal process for Pickering B (2013) and Darlington (2014).

The project can be divided into three major phases (see diagram below):

1. The initial scope of R&D work was identified and refined through early engagement with the CNSC during the first phase (2009-2010).
2. The CNSC Protocol, which specifies the critical R&D scope that must be accomplished by December 2012, was agreed to and signed by OPG and the CNSC in February 2011 as part of the second phase activities (2011-2012). This phase will now concentrate on execution of the defined R&D program to support the delivery of a high confidence statement to the OPG Board of Directors on pressure tube end-of-life for both Darlington and Pickering.
3. The third phase, beginning in January 2013, will focus on the post R&D activities described above. Additional support to integrate R&D results into Life Cycle Management Plans (LCMPs) will be provided to 2015. The planned completion date of the project is June 30, 2015.



# Fuel Channel Life Management Project 10 - 62444 (OM&A)
# & Spacer Retrieval Tool Project 28 - 66567 (Capital)
# Partial Release Business Case Summary N - BCS - 31100 - 10006 - R000

***28-66567 Spacer Retrieval Tool Sub-Project (Capital) – Rationale of Recommendation:***

All Darlington and some Pickering B replacement fuel channels are made of Inconel X-750, a material which will degrade under irradiation. In June 2009, tight-fitting spacers retrieved during a Darlington single fuel channel replacement (D3Q13) were damaged during transportation. Consequently, testing of these ex-service spacers to demonstrate on-going fitness-for-service has added challenges. To support this testing, specialized tooling that will not cause damage to the component is needed for future spacer retrieval and transportation.

The estimated total cost for the tooling development is $3.2M. An initial release of $0.87M was approved in 2010 and is currently being used to carry out project initiation efforts and to fund a vendor contract for the design and development of a manual-operated tool. This phase will finish at the end of 2011. A second release of $2.2M is requested at this point to fund tool production and commissioning activities to the end of 2012. If the manual tooling is unable to deploy across the length of the channel, then an alternative new design involving automation will be developed. If this second concept is utilized, the incremental cost would be [redacted] (already included as a specific contingency item). Regardless of design approach, this new spacer retrieval tool will be commissioned and readied for first use in 2012. Potential increase to outage duration is estimated at 24 hours per single fuel channel replacement. This duration will be optimized during outage pre-planning. The results from testing retrieved spacers will be utilized for validating the fuel channel fitness-for-service predictive model.

| $000's (incl contingency) | Funding | Type | LTD Dec 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Currently Released | Partial | OM&A | 8,991 | 8,978 | | | | | | **17,969** |
| | | Capital | | 867 | | | | | | **867** |
| Adjustments to Current Release | Adjustments | OM&A | (819) | | | | | | | **(819)** |
| | | Capital | | | | | | | | |
| Requested Now | Partial | OM&A | | 3,852 | 13,403 | | | | | **17,255** |
| | | Capital | | 72 | 2,145 | | | | | **2,217** |
| Future Funding Req'd | Full | OM&A | | | | 3,332 | 1,861 | 332 | | **5,525** |
| | | Capital | | | | 82 | | | | **82** |
| Total Project Costs | | OM&A | **8,172** | **12,830** | **13,403** | **3,332** | **1,861** | **332** | **-** | **39,930** |
| Total Project Costs | | Capital | **-** | **939** | **2,145** | **82** | **-** | **-** | **-** | **3,166** |
| Total Project Costs | | Total | **8,172** | **13,769** | **15,548** | **3,414** | **1,861** | **332** | **-** | **43,096** |
| Other Costs | | | | | | | | | | **-** |

| Investment Type | Class | NPV | IRR | Discounted Payback |
|---|---|---|---|---|
| **Sustaining** | **Multi Class** | **2,000,000** | **N/A** | **N/A** |

Submitted By: (Date)
2011-07-20
W. Robbins
Chief Nuclear Officer

Submitted By: (Date)
20 July 11
A. Sweetnam
**EVP, Nuclear Refurbishment Projects & Support**

Financial Approval By: (Date)
Aug 12/11
D. Hanbidge
SVP & Chief Financial Officer

**(OAR Element 1.1 Project in Budget)**
Line Approval By: (Date)
18 Aug 2011
T. Mitchell
President &Chief Executive Officer

**Fuel Channel Life Management Project 10 - 62444 (OM&A)**
**& Spacer Retrieval Tool Project 28 - 66567 (Capital)**
**Partial Release Business Case Summary N - BCS - 31100 - 10006 - R000**

## 2/ BACKGROUND & ISSUES:

The degradation mechanisms impacting pressure tube fitness-for-service described below affect all CANDU units, including Pickering A, Pickering B and Darlington units. However, they have varying degrees of impact on different stations due to station design and operating conditions.

***Deuterium ingress and its impact on material properties***

During hot operation, pressure tubes react with the heavy water coolant and, as a consequence of this, the concentration of hydrogen (deuterium and protium, quoted in terms of the equivalent hydrogen concentration, $H_{eq}$) increases over time. As well, in the pressure tube/end fitting rolled joint region, there is an additional galvanic corrosion component which makes the process in this region much more rapid. Since pressure tube material has a limited solubility of hydrogen which increases with increasing temperature, a brittle hydride phase can form - which makes fuel channel pressure tubes susceptible to an active cracking mechanism, delayed hydride cracking (DHC).

Because of the limited fracture toughness data available for high $H_{eq}$ conditions, CSA (Canadian Standards Association) N285.8 limits the allowable $H_{eq}$ in the main body of a pressure tube (BOT) and in the tensile portion of the rolled joint (RJ) region to 70 ppm at the inlet and 100 ppm at the outlet. These values in CSA N285.8 impose a hard limit for operation. Moreover, with limited fracture toughness data at high $H_{eq}$ values, it is challenging to demonstrate the safe operation at $H_{eq}$ values approaching N285.8 limits.

As a result, OPG fuel channel experts have only medium confidence (up to 70%) that the pressure tubes in Darlington will achieve the target service life of 210k EFPH or beyond. This is due to the fact that Darlington Unit 3 scrape samples in 2002 exhibited some very high uptake trends that exceeded the upper bound of the CANDU 6 model, and that Darlington pressure tubes have some of the highest initial impurity hydrogen ($H_{initial}$) values in any CANDU units. Other contributing factors include a scarcity of rolled joint $H_{eq}$ data, a lack of scrape data from the Darlington units to support model predictions and the lack of a validated predictive rolled joint model. If the current CSA N285.8 limits are reached in Darlington earlier than 210k EFPH, then it may be necessary to advance the refurbishment schedule from the current plan of 2016. As it takes more than 5 years to properly prepare for refurbishment, the Darlington Refurbishment project, as a risk mitigation strategy, is planning to be ready to commence the refurbishment as of October 2015. It should be noted that a start earlier than October 2015 would significantly increase the risk of adequate project performance of the Refurbishment project. Additionally, there will be a significant loss in economic value if the Darlington units need to be refurbished earlier and/or if units are idled pending refurbishment. Aside from issues concerning reaching this $H_{eq}$ limit, it should be recognized that there are little high hydrogen material property data from ex-service pressure tubes. Hence, there is insufficient data to provide the needed technical basis supporting operation of pressure tubes with $H_{eq}$ above the current CSA N285.8 limit.

Until recently, Pickering B was not expected to exceed the CSA N285.8 limits during the pressure tube original planned life of 210k EFPH. This expectation was related to the lower operating temperatures and pressures in Pickering B. However, the hydrogen and deuterium profiles through the inlet and outlet rolled joint regions of surveillance tube P6 M14 have challenged this expectation. It appears that P6 M14 has much higher deuterium uptake in the compressive regions of the pressure tube.

In summary, the following concerns regarding deuterium ingress need to be addressed in a timely manner for OPG to make confident predictions of pressure tube life in order to optimally plan potential refurbishment activities and achieve continued operations:

a) Pressure tube material property changes with high $H_{eq}$;
b) Kinetics of deuterium ingress (increasing $H_{eq}$) in the rolled joint region - to project future values and predict when fitness-for-service values will be reached; and
c) The appropriateness of the current limits.

If it is demonstrated that there remains an adequate margin on material properties with high $H_{eq}$, changing the limits may be justified. Refined deuterium uptake rate prediction capability may also increase confidence that Darlington can operate to 210k EFPH or beyond and that Pickering B can operate to 240k EFPH or beyond.

### *Spacer Integrity and PT/CT Contact*

Annulus spacers perform the critical function of maintaining a gap between the pressure tube and calandria tube – to assure that contact between these components cannot occur. Pressure Tube to Calandria Tube contact (PT/CT contact) led to the failure of the pressure tube in channel G16 of Pickering Unit 2 in 1983. As such, spacer integrity and the maintenance of a PT/CT gap must be demonstrated over the full operating life of the reactor.

The spacers used in Darlington are a tight-fitting design made from Inconel X-750. Removal of pressure tubes and spacers from Darlington Unit 2 Channel O18 in 2005 and from Darlington Unit 3 Q13 in 2009 has indicated that the structural integrity of this spacer design may be degrading. Although visual inspection evidence obtained during pressure tube removal indicates that the spacers were intact, after transport they arrived at testing laboratories in several pieces, which is an indication that some material properties had been degraded. Although the flasking and transportation may have led to the ultimate failure of these spacers, their degraded properties are due to operation. It is unknown at this time whether the in-service degradation in properties of spacers at Darlington has saturated or if degradation will continue. This issue is one that could result in premature shutdown of Darlington units, since failure of a spacer would lead to increased risk of PT/CT contact in the outlet region of the pressure tubes in Darlington, which could result in hydride blister formation and subsequent pressure tube rupture.

OPG technical staff and the CNSC have raised questions regarding the validity of data obtained from the damaged spacers. Testing an undamaged tight fitting spacer allows the actual properties of the irradiated spacers to be established. The next planned Darlington spacer retrieval is in the fall of 2013. However, OPG has an opportunity to obtain early X-750 material degradation data from Bruce Power spacers. Bruce B uses non-optimized Inconel X-750 spacers and may choose to conduct a single fuel channel replacement in 2012. Bruce B Unit 8 spacer properties were first examined in 1999 (82,225 EFPH), and comparing this data to the test results of Bruce B spacers retrieved in 2012 would provide OPG with the Inconel X-750 material property degradation rate.

Although the material properties of the loose-fitting Zr-Nb-Cu spacers in Pickering B are considered to be adequate for a 240k EFPH pressure tube life, the root cause investigation of the failed calandria tube in Pickering Unit 7 channel A13 revealed significant spacer wear as well as wear on the pressure tube and calandria tube surfaces. This finding calls into question whether the spacers in Pickering B are capable of maintaining an adequate PT/CT gap for a 240k EFPH pressure tube life. The root cause investigation team has produced an interim report, but additional activities are required to determine the root cause of spacer wear, the extent and severity of spacer wear in OPG reactors, and the impact of worn spacers on PT/CT contact predictions.

Currently, there is no program to periodically assess spacer integrity as they can only be examined when a fuel channel pressure tube is replaced. Moreover, spacers are not part of the normal surveillance activities associated with fuel channel replacement. Therefore, a spacer surveillance program will be developed to assure structural integrity over the full operating life of the units. Elements of this program include: a comprehensive literature survey to determine the credible degradation mechanisms and subsequent assessment methods, procedures and acceptance criteria for the results.

The CNSC has clearly indicated that actual in reactor measurements of the gap between a pressure tube and a calandria tube is required for validation of the assessment methodology. OPG has launched Project 28-66255 (Gap Measurement tooling development) to enable actual data collection. The gap data are needed to validate results of this project.

### *Crack Initiation*

Flaws in Pickering B pressure tubes were generated during commissioning due to construction debris entrained in the Primary Heat Transport System (PHTS). These flaws can initiate cracks and lead to failure of the pressure tube. The risk level depends on the type, size, and location of a flaw. The mechanisms which may allow initiation of a crack from an existing flaw include delayed hydride cracking (DHC), transient stresses (overload), and fatigue. The CSA standard N285.4 and N285.8 specifies acceptance criteria of flaws.

Flaws that fail to satisfy the acceptance criteria provided in CSA N285.4 must be evaluated for acceptability and the condition must be dispositioned with the regulator. CSA N285.8 provides the recognized and accepted means of assessing flaws. One requirement is to demonstrate that crack initiation will not occur from DHC, fatigue and hydrided region overload. Pickering B currently has a number of flaws where crack initiation criteria are not satisfied. This has resulted in the imposition of limits on the number of heat up/cool down cycles on operation and a requirement for re-inspection to assure that there has been no crack initiation and propagation. Although crack initiation has never been observed, these flaws continue to be monitored with a decreasing number of available cycles due to increasing deuterium concentration in the pressure tubes. Procedures currently used to assess flaws carry a significant degree of conservatism which is becoming increasingly limiting.

Test programs are underway to address the conservatism in modeling flaw behavior involving the use of more realistic flaw geometries, $H_{eq}$ and sample conditioning. Initial results have shown much greater resistance to crack initiation in pressure tubes using these conditions than the assumptions used in the original model. However, test programs are proceeding at a pace that would not produce the desired results by 2012 as required by OPG to better plan possible refurbishment activities.

A recent attempt to modify the evaluation procedure for fatigue crack initiation was not accepted by the CNSC based on limited data to support the proposed changes. Following this, an 'interim approach' was adopted with a commitment to produce more data in the next few years to support the original request. This would include work to capture any environmental (reactor water) effects.

Additional testing to support changes to all crack initiation mechanism evaluation procedures would increase the acceptable flaw size envelope (especially for Pickering B) by showing that pressure tubes currently in service have a higher resistance to crack initiation than they are currently given credit for in assessments.

### *Probabilistic Core Assessments and Leak-Before-Break*

CSA N285.8 requires that probabilistic core assessments be conducted to demonstrate that the probability of pressure tube rupture remains acceptably low, and that leak-before-break capability remains.

In addition to evaluating flaws found during inspections, the condition and acceptability of the pressure tubes in the reactor core as a whole must be evaluated using a Probabilistic Core Assessment (PCA). Among other input information, data from crack initiation experiments and the subsequent evaluation methodologies in the PCAs which impact on the probability of pressure tube rupture are to be evaluated against an acceptance criterion. The current state-of-the-art understanding of crack initiation is not captured in the current PCA code and, for this reason, the results are considered to be conservative. As well, the tool is not qualified to the industry standard of CSA N286.7. This exposes OPG to some regulatory risk.

Leak-before-break refers to the scenario where a postulated through-wall crack in a pressure tube results in a leak into the Annulus Gas System which is detected and subsequent operator actions are taken to place the reactor in the cold and depressurized safe state prior to reaching the extent of crack propagation when a pressure tube would fail catastrophically. Assurance of this capability is becoming increasingly difficult as the pressure tube properties degrade with time, and a change in methodology and/or input parameters can have a significant impact on the margin.

### *Regulatory Engagement*

To facilitate the upcoming license renewal activities, a protocol was signed between OPG (in partnership with Bruce Power) and the CNSC in February 2011 (N-CORR-00531-05133). The CNSC and the FCLM project have agreed to two critical issues ("Propositions"), for which OPG requires a positive response from the Regulator by the end of 2012 to facilitate license renewal for Pickering and Darlington sites. License renewal is the first critical step to allow continued operation of Pickering B and to provide schedule flexibility for the Darlington Refurbishment Project. These Propositions are as follows:

1. Establish a fracture toughness model of upper/transition/lower shelf behaviour for Heq >100 ppm.
2. Demonstrate that PT/CT gap is maintained to 2014 for each station.

The CNSC Protocol specifies eighteen documents to be submitted by the FCLM project to the Regulator. Acceptance of these submissions will support the resolution of the two Propositions listed above. Additionally, the FCLM project is providing regular updates to the CNSC regarding technical issues.

The CNSC recognizes that OPG has adequate capabilities in the Crack Initiation Assessment and Probabilistic Core Assessment areas at present and hence did not include these issues in the Protocol. The CNSC also indicated that they will not have the resources before 2012 to review submissions on these two areas. However, the FCLM project anticipates that the improved methodologies for Crack Initiation Assessment and Probabilistic Core Assessment will be required toward the end of planned operations. Hence, it is proposed that the FCLM project timeline be extended to allow the project staff to submit the technical basis for these improved methodologies starting in 2013.

While the CNSC Protocol addresses the license renewal process, the application of new methodologies must follow the established Regulator process. Thus, starting in 2013, submissions to the CNSC for application of new methodologies at specific sites must be done to ensure these approaches can be used in the later years of planned continued operations.

### *Oversight of Supporting Activities*

In early 2011, OPG Internal Audit made recommendations to FCLM project to include or strengthen the following activities to ensure success of Continued Operations at Pickering B and the Refurbishment Project at Darlington:

1. Finalize the Regulatory Strategy
2. Identify risks of the supporting activities and oversee management of these risk items
3. Identify and oversee critical OPG supporting activities and ensure that controls are established to effectively manage the interdependencies
4. Develop a standard suite of project reports to ensure alignment of all business units and up to date briefing of senior management
5. Appoint a senior manager to oversee the "broader picture"

Corrective action plans were developed and accepted by Internal Audit. All corrective actions were completed by May 2011, and the audit has since been closed. However, the implementation of the plan has added scope to the FCLMP for the duration of the project. This additional scope includes the following on-going activities:

1. Development and maintenance of a project risk management plan (N-PLAN-31100-10007) and risk register
2. Engagement of OPG stakeholders
3. Engagement of CNSC – technical and licensing personnel
4. Communication of project and/or activity progress between supporting departments and the FCLM project
5. Integration of R&D results into long term strategic planning to support Pickering Continued Operations and Darlington Refurbishment

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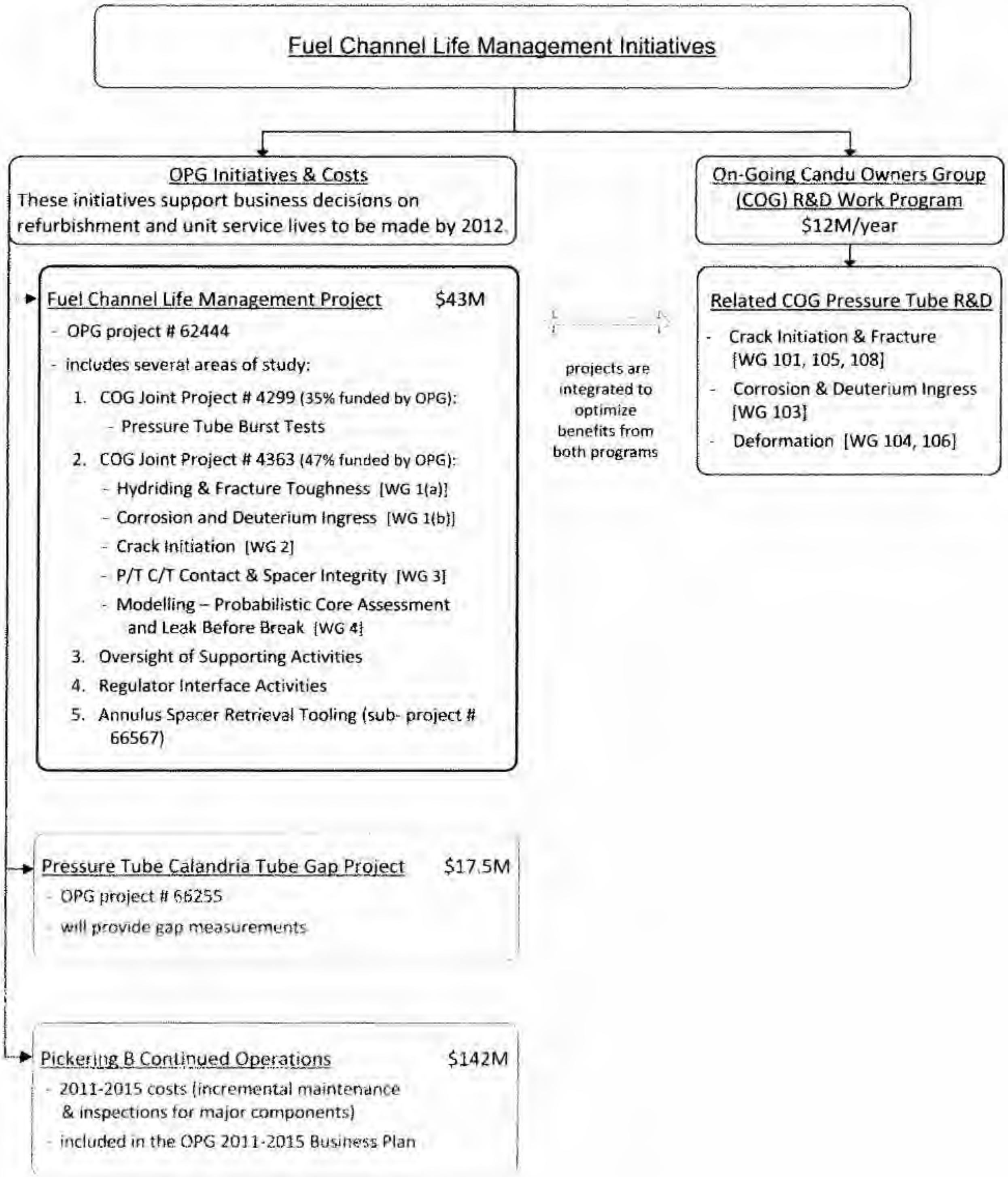
OPG's Fuel Channel Life Management Initiatives can be summarized by the following figure:



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## 3/ ALTERNATIVES & ECONOMIC ANALYSIS:

| Major Assumptions | Base Case | Alternative 1 (Recommended) |
|---|---|---|
| FCLM Project costs (includes spacer retrieval program) | None | $43.1M |
| PT/CT Gap Measurement Project costs | None | $17.5M |
| Pickering B Continued Operations Project costs | None | $142M |
| Pickering A Unit End of Life (EOL) Date | Shutdown with 2nd last PB unit | Shutdown with 2nd last PB unit |
| Pickering B Unit EOL Date | 210k EFPH assumed (2014–2016); P7 life managed | 240k EFPH assumed (2018–2020; P7 life managed |
| Darlington Unit EOL Date before refurbishment: unit EOL date based on 92% capacity factor | 187k EFPH assumed or Refurb Outage Start Date if earlier | 210k EFPH assumed or Refurb Outage Start Date if earlier |
| Darlington Refurbishment Outage Schedule with 36 month unit outages and 16/19 month overlaps | First unit outage begins Oct 2015 | First unit outage begins Oct 2016 |
| Station Operating Costs | Based on 2011–2015 Business Plan and extrapolated | Based on 2011-2015 Business Plan and extrapolated |

**Base Case:** ✗ *Not Recommended* - **Continue with current COG R&D program to support Fuel Channel FFS (Do nothing)**

At the pace with which fuel channel R&D was proceeding under COG, the results of testing and associated analyses would be not be completed in time to demonstrate high confidence (>70%) in fitness-for-service beyond 210k EFPH for Darlington and beyond 240k EFPH for Pickering B by 2012. This could result in Darlington units reaching their end-of-life as early as 187k EFPH with the refurbishment advanced from 2016 to 2015 with a substantial increase of refurbishment project risks and a substantial reduction in economic value due to shorter life and/or idle time pending refurbishment. For Pickering B, support for the technical basis for operation of fuel channel components to 240k EFPH will likely not have the required confidence by 2012 if the work were not accelerated.

**Alternative 1:** ✓ *Recommended* - **Prioritize R&D and provide oversight to supporting activities**

Completing the key R&D activities, as specified and committed to in the CNSC Protocol, in conjunction with executing planned inspections and maintenance under OPG's fuel channel inspection program before the end of 2012 will help demonstrate whether there is high confidence (>70%) that Darlington units can operate to 210k EFPH or beyond and Pickering B can operate to 240k EFPH or beyond.

It is anticipated that a significantly reduced but continued effort will be required in 2013 and beyond to complete non-critical and discovery R&D work. Support for regulatory interface activities, including license renewal and delivery of outstanding CNSC commitments, will be provided to the end of 2014. Oversight of supporting activities, including the integration of R&D results into Life Cycle Management Plans, will be provided by FCLMP to mid-2015. Completion of the proposed work will allow refurbishment activities to be planned effectively at Darlington. The operation of Pickering B to 2020 would realize greater economic value from these units.

**Alternative 2:** × *Not Recommended -* **Conduct a portion of the work proposed (Do Less)**

This alternative is a reduction in scope over the recommended Alternative 1. R&D work that is not committed to in the CNSC Protocol would be removed from the scope. However, the capability to provide a high confidence statement by the end of 2012 would be impaired. In addition, methodologies required to validate fitness for service in later years would not be available.

This alternative is not recommended based on the need to support high confidence (>70%) projections of operating Darlington units to 210k EFPH or beyond (from 187k EFPH) and Pickering B units to 240k EFPH or beyond (from 210k EFPH). OPG will not be able to make a business decision on continued operations based on critical technical information.

**Alternative 3:** × *Not Recommended -* **Request Regulatory Relief on Life Limiting Issues**

In the area of pressure tube fitness-for-service, several submissions to revise the fitness-for-service methodologies (or inputs to these methodologies) have not been completely accepted by the regulator and 'interim approaches' have been utilized which include commitments to conduct additional work to justify the original submissions. By requesting relief in areas where commitments have been given (including some cases with formal plans) to justify previous submissions, the regulator may lose confidence in OPG since the regulator may already consider the 'interim approaches' to be a form of relief. Moreover, technical experts in the industry share most of the concerns of the regulator, and it would be prudent to get the appropriate answers rather than requesting relief.

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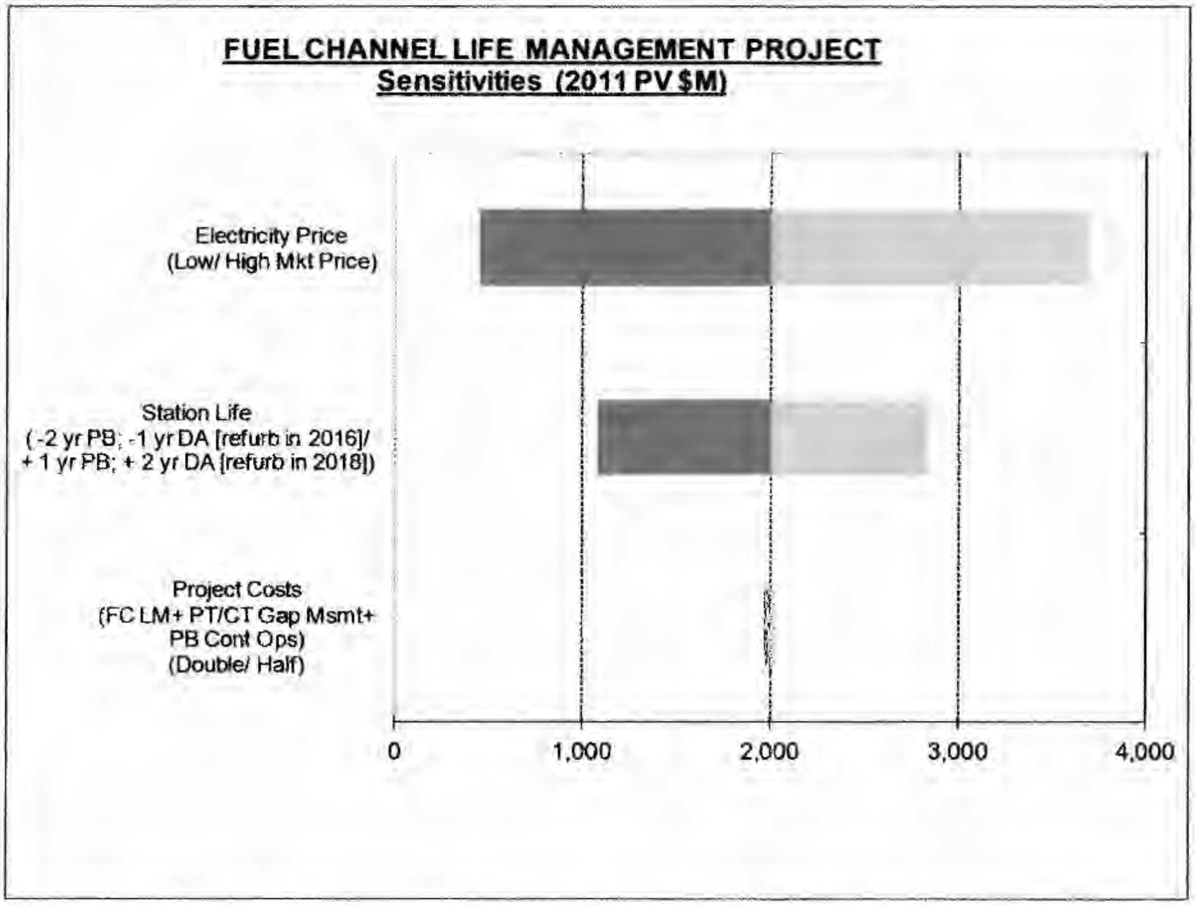
## Economic Analysis

Alternatives 2 and 3 were not analyzed economically as they are not considered to be feasible in achieving the desired objectives. The value to the provincial electricity customers of Alternative 1 compared to the Base Case is estimated at $2 Billion. The following graph shows the key sensitivities of the results.



Results of the economic assessment were tested for sensitivity to key inputs such as assumed electricity price, length of additional station life achieved, and project costs, and indicate the following:

i. Assumed Electricity Price: The value is extremely sensitive to the assumed electricity price. In a high price regime, the value would be approximately $3.7 Billion and in a low price regime, the value would be approximately $0.45 Billion. A low price regime would result from low electricity demand and low gas prices (such as during a prolonged economic slowdown) and/or high conservation.

ii. Length of Additional Station Life Achieved: The value is sensitive to the station life that can be achieved with high confidence. If Pickering B units achieve only 225k EFPH and Darlington units achieve only 202k EFPH with Darlington refurbishment starting in 2016, then the value would be $1.1 Billion. If the Pickering B units achieve 248k EFPH and the Darlington units achieve 225k EFPH with Darlington refurbishment starting in 2018, then the value would be $2.8 Billion.

iii. Project Costs: The value is insensitive to project costs. Project costs include the costs of the integrated fuel channel life management project, the PT/CT gap measurement project and the Pickering B Continued Operations costs. The sensitivity analysis shows that a doubling of these costs has a minimal impact on the expected PV.

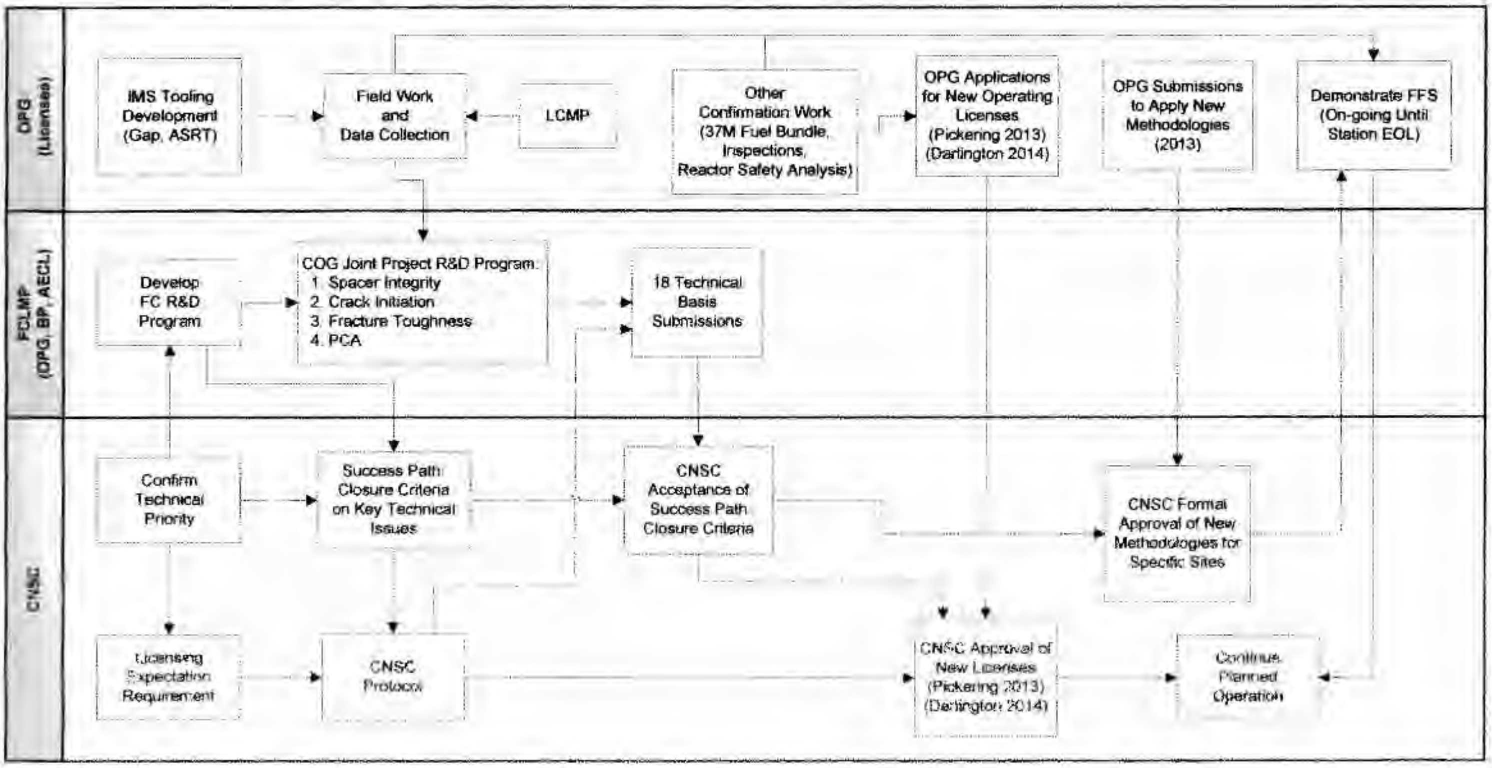
## 4/ THE PROPOSAL

### *Overall Approach*

It is proposed that funding be made available to continue to execute a fuel channel life management project. This project will be characterized primarily by an accelerated research program, to be substantially completed by end of 2012, which allows integration of information from existing programs (COG R&D programs and OPG fuel channel inspection programs) to formulate a new technical basis and refined methodologies to allow justification of continued operations. By this approach, the refined methodologies and new acceptance criteria will be incorporated into current inspection techniques to support the confirmation of extended fuel channel life predictions. The development of specialized tooling (Gap Measurement and Spacer Retrieval) is required to enable the collection of data mandated under the inspection program as input or validation data for the new technical basis and methodologies.

The research program deliverables are guided by the CNSC Protocol. Expectations for each R&D activity will be measured against defined closure criteria, which have been identified and agreed to by OPG and the CNSC. Additional research work will be conducted in order to support the update of the fuel channel fitness-for-service assessment model and methodologies. Formal submissions will be made to the CNSC to request regulatory acceptance to apply the new technical basis and to use the refined methodologies and new acceptance criteria.

The relationships of the programs/project mentioned are shown in the diagram below.



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***Project Objectives and Scope***

The objectives of this project are listed below. The original project objective, as described in the previous BCS Partial Release, has been expanded in order to satisfy the recommendations of Internal Audit.

1. Provide a high confidence statement of the targeted service life of Pickering and Darlington fuel channels to the Board of Directors by the end of 2012.
2. Complete and submit to the CNSC the R&D deliverables that are critical to CNSC's licensing decisions for Pickering and Darlington stations by December 2012.
3. Manage post R&D activities for transition into the base organization.

To accomplish these objectives, the project scope includes the activities listed below. Additional scope has been added to this release to satisfy the recommendations of Internal Audit and is denoted by an asterisk (*).

1. Monitor and control project cost and schedule
2. Liaise between COG project manager and OPG management on technical progress and risk management
3. Maintain continuous engagement with the CNSC
4. Support license renewal process at Pickering B and Darlington
5. * Execute the project risk management plan, including risk monitoring and performing risk mitigation actions
6. * Provide oversight to the development of the Annulus Spacer Retrieval Tooling (ASRT)
7. * Support the integration of new technical basis and refined methodologies into LCMPs

The project will be executed in three major phases, which are outlined as follows:

- **Phase 1 (Sept 2009 – Dec 2010):** R&D Definition and CNSC Engagement ***(Completed)***

  The initial scope of R&D work was identified and refined through early engagement with the Regulator. The CNSC Protocol, which specifies the critical R&D scope that must be accomplished by December 2012, was agreed to and signed by OPG and the CNSC in February 2011.

- **Phase 2 (Jan 2011 – Dec 2012):** R&D Execution and Meeting CNSC Requirements to Confirm FC FFS

  Execution of R&D scope is in progress and the project is currently providing oversight to the development of the ASRT. The closure criteria for critical R&D activities have been agreed to by the CNSC and OPG. The project will deliver R&D submissions to the Regulator according to the CNSC Protocol and a high confidence statement to the OPG Board of Directors on pressure tube end-of-life for both Darlington and Pickering by December 2012. The project will begin to prepare specific license submissions to support Pickering B continued operations in 2012.

- **Phase 3 (Jan 2013 – Jun 2015):** Integration of R&D to Support License Renewals

  All R&D results will be integrated into Life Cycle Management Plans (LCMPs) in order to confirm fuel channel Fitness for Service (FFS). Specific license submissions will be prepared ahead of Pickering B license renewal in July 2013, and a long term spacer management plan will be developed ahead of the Darlington license renewal in 2015. The planned completion date of the project is June 30, 2015. Continuous engagement of the CNSC and stakeholders will be maintained throughout this stage.

***Technical Program Plans***

The following work includes the total current project work scope to be conducted between 2011 and 2012 as a joint project between OPG and industry partners. The first two areas of work (Deuterium Ingress and its Impact on Material Properties & Spacer Integrity and PT/CT Contact) have been identified as critical by the CNSC in the Protocol.

**Deuterium Ingress and its Impact on Material Properties (Critical R&D)**
Two methods of adding hydrogen (called "hydriding") to irradiated pressure tubes in a manner that does not affect existing irradiation damage are currently being tested. In September 2011, one method will be selected to produce hydrided pressure tube samples which will be tested to determine facture toughness at proposed end-of-life conditions. These tests will be conducted as proposed in the COG Joint Project 4299. Information from full scale tests will be integrated with data from the standardized small sample tests to produce engineering fracture curves.

Other activities to support deuterium ingress projections will be conducted including: developing detailed requirements for rolled joint $H_{eq}$ model to ensure that the modification of current code addresses concerns over the lack of predictability; updating the body-of-tube deuterium ingress model to improve the accuracy of long term predictions; and using existing and new data/models to calculate the time to reach specified $H_{eq}$ values for all units.

**Spacer Integrity and PT/CT Contact (Critical R&D)**
The properties of tight fitting spacers used in Darlington fuel channels and Pickering replacement fuel channels (made of Inconel X-750), may degrade under a radiation field. The irradiated properties need to be established from retrieved spacers that did not suffer from damage in the retrieval process or the subsequent transportation. Testing of broken spacer casts doubt on whether the actual properties have been captured and the CNSC has raised similar questions. It is critical to have confidence that these spacers will carry out their designed functions for their target service life. As such, this work has been identified by the CNSC as critical R&D which must be completed by December 2012. Development of tooling capable of retrieving spacers without inducing any damage is an important step to establish spacer properties for continued operations at Darlington.

To address concerns over tight-fitting spacer integrity, the major scope of work includes: determination of the mechanism of degradation of Inconel X-750 spacer material, development of a comprehensive program of condition monitoring, including evaluation methods and acceptance criteria for examination of ex-service spacers, and pursuing the implementation of PT-CT gap measurements to assure spacer integrity and capability to maintain an appropriate gap. A literature review to identify the knowledge has been a key input to the work program just described. Also, the feasibility of an experimental program to irradiate Inconel X-750 to determine the rate of degradation in early life for extrapolation and projection to late life operation is being undertaken.

To address the concerns over loose-fitting spacer wear, the major scope of work includes: completing the actions identified by the root cause investigation for P7A13 calandria tube leak, determination of the impact of spacer wear on PT-CT predictions, and examination of other available ex-service spacers to determine the possible extent of spacer wear in OPG reactors.

The key deliverable from this work program is to provide assessment on spacer integrity and mobility, and to identify spacer surveillance requirements. Also, the predictive capabilities for PT/CT contact will be assessed, and upgraded by comparing gap predictions from contact models with PT/CT gap measurements obtained from reactors.

**Crack initiation**
Tests using more realistic sample geometries and conditioning cycles will be conducted to quantify increased crack initiation resistance. This will allow most known flaws in Pickering pressure tubes to pass fitness-for-service evaluations in the future as well as support Probabilistic Core Assessments.

The work includes: quantifying the positive benefit of reduced pressure shut down on crack initiation, increasing the variability and $H_{eq}$ validity range on the non-ratcheting factor, and crediting the benefits of finite length flaws and angled volumetric flaws. Preliminary assessments of this type of work has indicated that pressure tubes are more resistant to crack initiation than current methodologies credit and, with the data to be acquired from these tests, the technical basis to modify fitness-for-service methodologies can be achieved.

Fatigue crack initiation experiments will be conducted in air on both ex-service material and unirradiated material, as well as in a reactor water environment on unirradiated material to support regulatory commitments to use the current 'interim approach' and make subsequent changes to the evaluation procedures. A task group is currently evaluating the benefit of testing ex-service irradiated material in a reactor water environment. Pickering B will be able to demonstrate acceptability of more flaws, remove cycle limitations imposed by fatigue crack initiation, and minimize inspection requirements. Third Party external experts have confirmed acceptability of proposed program for evaluation of fatigue for irradiated material in reactor environment.

**Probabilistic Core Assessments and Leak-Before-Break**
The Probabilistic Core Assessment tool will be updated to reflect the current understanding of fuel channel degradation, as determined by other parts of this project, to offer a more realistic assessment of reactor core integrity. In addition, the tool will be qualified to the requirements of CSA N286.7, as an Industry Standard Tool (IST).

Improvement of the current Leak-Before-Break methodology to include a probabilistic approach of selected parameters is also being explored.

The project work will also include ensuring that condition monitoring prescribed in the OPG Fuel Channel Aging and Life Cycle Management Strategy and Plan is executed. The resultant data is essential to determine when fitness-for-service limits will be reached. In addition, it is essential that experimental results be analyzed and technical basis documents developed to support improved methodologies meeting technical and regulatory requirements.

## 5/ QUALITATIVE FACTORS

This work is part of an industry-wide initiative to gain greater certainty on the fitness-for-service limits for fuel channels. As this is being executed as a COG Joint project, it gives all industry partners important information concerning the timing of possible refurbishment activities. This will help the industry to optimize refurbishment plans, and may reduce the strain on resources to conduct refurbishment of many units in parallel. It would also help to manage a significant impact on the availability of base load nuclear generation in the Province.

Even if it is determined that the current base case is accurate, and Darlington refurbishment activities must be brought forward in time from 2016, this project provides valuable knowledge to enable an orderly approach to Darlington unit refurbishments and to the management of remaining service life of Pickering B units.

This work is part of a comprehensive Fuel Channel Life Management Plan which has been developed to drive to higher levels of confidence in longer pressure tube lives for the OPG nuclear units. Achieving higher levels of confidence has many benefits which are not easy to quantify including providing enhanced flexibility to OPG to:

(i) Manage the lead time constraints, and other preparatory issues (e.g. resource constraints, long lead time material, project mobilization) and manage the overall refurbishment schedule for the nuclear units, particularly the uncertainty around the refurbishment schedule for the Darlington units given current uncertainties in unit service life;
(ii) Manage the uncertainties created by any potential delays to new nuclear in-service dates; and
(iii) Manage the potential significant capital and resource requirements and financial sustainability of OPG associated with multiple simultaneous refurbishments and new build nuclear campaigns;
(iv) Enhance OPG credibility with CNSC
(v) Manage the Provincial power supply

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## 6/ RISKS ANALYSIS (See Attachment D for details)

Risk Associated with the Fuel Channel Life Management Portion (OM&A)

| Low<br>1 to 3 | Medium<br>4 to 9 | High<br>10 to 25 | | | |
|---|---|---|---|---|---|
| | **Impact** | | | | |
| | 1 | 2 | 3 | 4 | 5 |
| **Probability** 5 | 5 | 10 | 15 | 20 | 25 |
| 4 | 4 | 8 | 12 | 16 | 20 |
| 3 | 3 | 6 | 9 | 12 | 15 |
| 2 | 2 | 4 | 6 | 8 | 10 |
| 1 | 1 | 2 | 3 | 4 | 5 |

| Risk Description | Mitigating Activities | Mitigation | Finance | Schedule | Quality | Corporate Reputation | Regulatory | Health & Safety | Environmental | Nuclear Safety | Risk Rating (1 to 25) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Specialized resources may be unavailable to do the work in the required timeframe. | Close collaboration with the COG fuel channel work program to ensure optimum utilization of existing resources.<br>OPG Senior Management involvement to ensure vendor commitments is met. | **Before** | | 16 | | | | | | | **16** |
| | | **After** | | 12 | | | | | | | **12** |
| Schedule delay due to incomplete planning of the following areas:<br>a) Discovery issue resolution process<br>b) Commissioning of new process and facility<br>c) CNSC review of submission documents | a) COG Project Manager to issue instructions and communicate on need to report promptly issues/ unusual results for resolution<br>b) Prepare equipment commissioning plan. Involve more technical experts. Obtain external consultant services from internationally established experts.<br>c) Agree on closure criteria ahead of review process to establish clear acceptance requirements. | **Before** | 15 | 20 | | | | | | | **20** |
| | | **After** | 10 | 10 | | | | | | | **10** |
| Results indicate degraded properties which impact on continued operations (including other stations). Specific examples are as the following:<br>a) Results from inspections show increased D-uptake rate in RJ<br>b) Irradiated spacer properties indicate that properties are continuing to degrade | Pre-establish performance criteria and evaluate impact<br>Monitor results progressively with hold points to ensure that expected performance attained and potential impact<br>Establish more comprehensive fitness-for-service assessments<br>a) Use this work as basis, if possible, for increasing EOL limits<br>b) More comprehensive assessments will be conducted to demonstrate fitness-for-service | **Before** | 10 | | | 10 | 10 | | | | **10** |
| | | **After** | 4 | | | 4 | 4 | | | | **4** |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Ability to construct a validated predictive model based on limited data | Complete planned test identified in COG joint projects. Use data from COG R&D programs.<br>Develop best model available and recommend confirmatory inspection program to support model developed. | **Before** | | | 12 | | | | | | **12** |
| | | **After** | | | 10 | | | | | | **10** |
| Delay in OPG supporting activities:<br>a) Planned inspection work not completed during outages to obtain necessary data<br>b) Delay in supporting activities such as the Gap and Spacer retrieval tooling development, and Outage inspections to provide required data may impact on viability or quality of the Fuel Channel Life Management Project deliverables. | Develop and understand scenarios where not all work is completed and devise alternate paths<br>a) Ensure stations are aware of the impact of not conducting inspection work in outages.<br>b) Develop OPG Stakeholder communication and decision making process at senior management level. | **Before** | | 10 | | 12 | | | | | **12** |
| | | **After** | | 5 | | 8 | | | | | **8** |
| Regulator may require changes of the project work scope or disallow use of the results in determination of fitness for service limits. | Obtain buy-in from regulator on project plan and approach to be undertaken<br>Keep the regulator informed of results as project progresses. Participate in the 'Success Path' process proposed by the Regulator | **Before** | | | | 6 | 12 | | | | **12** |
| | | **After** | | | | 2 | 3 | | | | **3** |

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Risk Associated with the Annulus Spacer Retrieval Tooling Project (Capital)

| Low<br>1 to 3 | | Medium<br>4 to 9 | | High<br>10 to 25 | |
|---|---|---|---|---|---|
| | Impact | | | | |
| | 1 | 2 | 3 | 4 | 5 |
| Probability 5 | 5 | 10 | 15 | 20 | 25 |
| Probability 4 | 4 | 8 | 12 | 16 | 20 |
| Probability 3 | 3 | 6 | 9 | 12 | 15 |
| Probability 2 | 2 | 4 | 6 | 8 | 10 |
| Probability 1 | 1 | 2 | 3 | 4 | 5 |

| | | | Probability X Impact | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Risk Description | Mitigating Activities | Mitigation | Finance | Schedule | Quality | Corporate Reputation | Regulatory | Health & Safety | Environmental | Nuclear Safety | Risk Rating (1 to 25) |
| High force may be required to push all 4 springs the length of the channel, which could impact the integrity of the annulus spacers and compromise the in-reactor condition. | This task evolution will have to be examined and tested on a mock-up. | Before | 6 | 4 | 3 | | | | | | 6 |
| | | After | 3 | 2 | 2 | | | | | | 3 |
| Without any modifications to the Roadrunner flask design or to transportation procedures, there is a risk that spacers will continue to be damaged in transit. | Tool design requirements document specifies the need for modifications to the flask. | Before | 6 | 8 | 12 | | | | | | 12 |
| | | After | 2 | 3 | 3 | | | | | | 3 |
| The sequence of how a Single Fuel Channel Replacement (SFCR) is normally performed will have to be reconfigured and could cause an increase in outage time greater than 24 hours. | The new procedure will have to be examined and tested on a mock-up. Obtain a letter of understanding from Darlington Outage Management in regard to the potential/ expected increase to the SFCR outage schedule associated with Annulus Spacer Retrieval. | Before | 8 | 10 | | | | | | | 10 |
| | | After | 4 | 2 | | | | | | | 4 |
| Pressure Tube Push could be more difficult as the springs lessen the friction experienced during the push. | New springs may have to be installed to assist with the push. | Before | 4 | 2 | | | | | | | 4 |
| | | After | 4 | 2 | | | | | | | 2 |
| Long lead items might affect schedule adherence. | Determine design requirements to tooling, with input from all stakeholders, early in the project and submit requests for proposals from vendors. Identify materials early in the project. | Before | 10 | 20 | | | | | | | 20 |
| | | After | 2 | 2 | | | | | | | 2 |
| After spacers are removed, there is a risk that the calandria tube could be damaged during pressure tube removal. | Detailed design requirements established early on. Develop devices (e.g. "dummy" spacers) to insert onto the pressure tube in place of the removed annulus spacers to minimize risk of damage to the calandria tube. Commission ASRT tooling on mock-up prior to first use. Consider having Calandria Tube Replacement (CTR) capability available before the Annulus Spacer Retrieval Tooling is deployed. | Before | 20 | 20 | 20 | | | | | | 20 |
| | | After | 4 | 4 | 4 | | | | | | 4 |

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## 7/ POST IMPLEMENTATION REVIEW

| Type of PIR: | Targeted Final AFS Date: | Targeted PIR Approval Date | PIR Responsibility (Sponsor Title) |
|---|---|---|---|
| **Simplified** | | 30-Jun-15 | **VP, Science and Technology Development Department** |

| | Measurable Parameter | Current Baseline | Targeted Result | How will it be measured? | Who will measure Person / Group? |
|---|---|---|---|---|---|
| 1. | Results received from experiments and analyses | 2016 assuming COG funding remains at current level, and appropriate task funded. | August 2012 | Date final results are received to support next parameter | Director, FCLMP |
| 2. | Issue memo regarding confidence (high confidence is >70%) on Pickering B FC service life to 240k EFPH based on experiment results and analysis | High confidence to 210k EFPH<br>Confidence level on FC service life to 240k EFPH is 50% | December 2012 | Fuel Channel experts concur with high confidence | Director, FCLMP |
| 3. | Issue memo regarding confidence (high confidence is >70%) on Darlington FC service life to 210k EFPH based on experiment results and analysis | High confidence to 185K EFPH<br>Confidence level on FC service life to 210k EFPH is 50% | December 2012 | Fuel Channel experts concur with high confidence | Director, FCLMP |
| 4. | Complete submission of technical basis to modify FFS to regulator | 2016 based on appropriate results (see Item 1) | December 2013 | Date of acceptance/ rejection by regulator on submission | Project Sponsor |
| 5 | Transfer of CNSC action (for new inspection requirements) to MCED | CNSC will grant only short-term licenses (i.e. 6 months) if new program is not implemented. | June 2015 | New inspection program is included in 2015 LCMP | Project Sponsor |

## APPENDIX "A' GLOSSARY (acronyms, codes, technical terms)

| | |
|---|---|
| ASRT | Annulus Spacer Retrieval Tool |
| BOT | Body of Tube |
| CNSC | Canadian Nuclear Safety Commission, Canadian regulator under the Nuclear Safety and Control Act |
| COG | CANDU Owners Group |
| CT | Calandria tube |
| D-ingress | With hot operation, deuterium enters pressure tube material |
| EOL | End-of-life, based on a target service life |
| FFS | Fitness-for-Service |
| $H_{eq}$ | Equivalent hydrogen concentration if all deuterium [D] were replaced with protium [H] ($H_{eq} = [H] + [D]/2$) |
| Hydriding | The process of adding hydrogen (deuterium or protium) to pressure tube material to simulate later life conditions |
| PCA | Probabilistic Core Assessment, used to evaluate degradation of all fuel channels based on established methodologies and inspection results |
| PHTS | Primary Heat Transport System |
| PT | Pressure tube |
| RJ | Rolled joint between the pressure tube and end fitting |
| CSA N285.4 | "Periodic inspection of CANDU nuclear power plant components"<br>This Standard specifies the inspection requirements for nuclear power plant components. Clause 12 outlined the inspection and evaluation requirements of fuel channel. This Standard is the basis of the OPG periodic inspection plant which is submitted to the CNSC. |
| CSA N285.8 | "Technical requirements for in-service evaluation of zirconium alloy pressure tubes in CANDU reactors"<br>The specific fitness-for --service evaluation requirements are listed in this Standard. |
| CSA N286.7 | "Quality Assurance of Analytical, Scientific and Design Computer Programs for Nuclear Power Plants"<br>This Standard specifies the requirements for the quality assurance program applicable to the design development, maintenance, modification, and use of analytical, scientific, and design computer programs that are used in nuclear power plant applications. |

## APPENDIX "B" Comparison of Total Project Estimates

| $ 000's | | This Appendix compares the Total Project Estimate for each BCS | | | | | | | | | | Total Project |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | ***Total Project Estimate*** (by Year incl Contingency) | | | | | | | | | |
| **BCS Type** | **Class** | **Mth** | **Yr** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **Later** | **Est** |
| Partial | OM&A | Aug | 2009 | 2,533 | 9,728 | 7,741 | 4,010 | 908 | | | | 24,920 |
| Partial | OM&A | Aug | 2010 | 2,489 | 6,502 | 8,978 | 6,841 | 2,188 | | | | 26,998 |
| Partial | OM&A | Aug | 2011 | 2,489 | 5,683 | 12,830 | 13,403 | 3,332 | 1,861 | 332 | | 39,930 |
| Partial | Capital | Aug | 2010 | 0 | 0 | 867 | 2,217 | 82 | | | | 3,166 |
| Partial | Capital | Aug | 2011 | 0 | 0 | 939 | 2,145 | 82 | | | | 3,166 |
| | | | | | | | | | | | | 0 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LTD Spent | OM&A | Dec | 2010 | 2,489 | 5,683 | | | | | | | 8,172 |
| LTD Spent | Capital | Dec | 2010 | 0 | 0 | | | | | | | 0 |
| LTD Spent | | | | | | | | | | | | 0 |

**Comments:**

The overall increase in the total project estimate by $12.9 Million is due to the OM&A portion of the project only.

## Fuel Channel Life Management Project 10 - 62444 (OM&A)
## & Spacer Retrieval Tool Project 28 - 66567 (Capital)
## Partial Release Business Case Summary N - BCS - 31100 - 10006 - R000

## APPENDIX "C" FINANCIAL MODEL – ASSUMPTIONS

### Financial Assumptions:

| | | | | | |
|---|---|---|---|---|---|
| Discount Rate: | **7%** | Cost Escalation (Yr) | **2%** | SR&D Opportunity | **Choose** |
| Progress Payments | **Choose** | Foreign Currency | **Choose** | Retainer Fee | **Choose** |
| Depreciation Rate (Capital) | **Choose** | PST | **Choose** | Interest Rate (Capital) | **Choose** |
| Revenue Rate | **Choose** | Leasing | **Choose** | Indexed Priced Contract | **Choose** |

**Comments:**

Please refer to the Major Assumptions table provided in section 3 of the BCS.

### Project Cost Estimate:

| | | | | | |
|---|---|---|---|---|---|
| Design Complete: | **Choose** | Fixed Price Contract | **Choose** | 3rd Party Estimate | **Choose** |
| Quality of Estimate | **Release +15% to -10%** | OPEX used | **Choose** | Lessons Learned | **Choose** |
| Similar Projects | **Yes** | Budgetary Quote | **Choose** | First Unit Actual Used | **N/A** |
| Firm Vendor Proposal | **No** | Cost Sharing | **Yes** | Competitive Bid | **Choose** |
| Reviewed by Sponsor | **Yes** | Fee for Service | **Choose** | Contracts in place | **Yes** |

**Comments:**

Please note that Variance to Business Plans includes contingency. (See Attachment A and B) (i.e. Variance to Budget is calculated by subtracting Project Funding and Contingency Funding from 2011-2015 Business Plan.)

### Rationale for Capital Cost Classification:

### Generation Plan Assumptions:

| Station | Unit | EOL or Refurb | MW | Planned Outages for Project Work | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Pickering A** | **1** | Jun-20 | 515 | | | | | | | |
| | **4** | Jun-20 | 515 | | | | | | | |
| **Pickering B** | **5** | Nov-18 | 516 | | | | | | | |
| | **6** | Nov-18 | 516 | | | | | | | |
| | **7** | Jun-20 | 516 | | | | | | | |
| | **8** | Jun-20 | 516 | | | | | | | |
| **Darlington** | **1** | Feb-18 | 878 | | | | | | | |
| | **2** | Oct-16 | 878 | | | | | | | |
| | **3** | Sep-19 | 878 | | | | | | | |
| | **4** | Jan-21 | 878 | | | | | | | |

**Comments:**

Fuel Channel Life Management Project 10 - 62444 (OM&A)
& Spacer Retrieval Tool Project 28 - 66567 (Capital)
Partial Release Business Case Summary N - BCS - 31100 - 10006 - R000

## APPENDIX "D"

## FINANCIAL MODEL – ASSUMPTIONS
### Impact on Operations

Please see Section 3 (Alternatives & Economic Analysis)

**Fuel Channel Life Management Project 10 - 62444 (OM&A)**
**& Spacer Retrieval Tool Project 28 - 66567 (Capital)**
**Partial Release Business Case Summary N - BCS - 31100 - 10006 - R000**

**ATTACHMENT "A"**

## PROJECT COST SUMMARY

Fuel Channel Life Management Project – OM&A Portion

| | $ 000's OM&A | LTD Dec 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Accounting Basis | Project Mgmnt & Support | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | | | [redacted] |
| | Engineering | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | | | | [redacted] |
| | Procurement | | | | | | | | | - |
| | Construction | | | | | | | | | - |
| | Other | | | | | | | | | - |
| | | | | | | | | | | - |
| | | | | | | | | | | - |
| | | | | | | | | | | - |
| | Interest (Capital Project) | | | | | | | | | |
| | **Project Costs** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | General Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Specific Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | - |
| | **Project Costs** | 8,172 | ~~12,890~~ 12,830 | ~~13,343~~ 13,403 | 3,332 | 1,861 | 333 | - | - | 39,930 |

| | $ 000's OM&A | | LTD Dec 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Funding Basis | **Current Release** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Adj to Current Release** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **This Release** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **TTD Released** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Future Releases** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Project Funding** | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Contingency Funding** | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Total Funding** | | 8,172 | 12,830 | 13,403 | 3,332 | 1,861 | 332 | - | (0) | 39,930 |
| Budget | **2011 - 2015 Business Plan** | | 8,991 | 7,807 | 8,012 | 2,188 | 0 | 0 | | | 26,998 |
| | **Variance to Budget** | | (819) | 5,023 | 5,391 | 1,144 | 1,861 | 332 | 0 | (0) | 12,932 |
| Other | **Removal Costs (above)** | | | | | | | | | | - |
| | **Inventory W / O** | | | | | | | | | | - |
| | **Spare Parts in Invent** | | | | | | | | | | - |

| **Reviewed by:** | **(Date)** | **Approved by:** | **(Date)** |
|---|---|---|---|
| Nicholas van den Brekel<br>Tom Lau N. C. VAN DEN BREKEL<br>Project Manager, FCLMP FOR T. LAU | 21 JULY 2011 | Imtiaz Malek<br>Director, FCLMP | 21 July 2011 |

# Fuel Channel Life Management Project 10 - 62444 (OM&A)
# & Spacer Retrieval Tool Project 28 - 66567 (Capital)
# Partial Release Business Case Summary N - BCS - 31100 - 10006 - R000

## ATTACHMENT "A"

## PROJECT COST SUMMARY

Annulus Spacer Retrieval Project – Capital Portion

| | $ 000's Capital | LTD Dec 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Accounting Basis | Project Mgmnt & Support | | 100 | 28 | | | | | | 128 |
| | Engineering | | 50 | | | | | | | 50 |
| | Procurement | | 625 | 100 | | | | | | 725 |
| | Construction | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Other | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | SAVH | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | | | | | | | | | - |
| | | | | | | | | | | - |
| | Interest (Capital Project) | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Project Costs** | - | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | General Contingency | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Specific Contingency | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Project Costs** | - | 939 | 2,145 | 82 | - | - | - | - | 3,166 |

| | | $ 000's Capital | LTD Dec 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Funding Basis | **Current Release** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Adj to Current Release** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **This Release** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **TTD Released** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Future Releases** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Project Funding** | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Contingency Funding** | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Total Funding** | | - | 939 | 2,145 | 82 | - | - | - | - | 3,166 |
| Budget | 2011 - 2015 Business Plan | | 0 | 867 | 2,217 | 82 | | | | | 3,166 |
| | **Variance to Budget** | | 0 | 72 | (72) | 0 | 0 | 0 | 0 | 0 | 0 |
| Other | **Removal Costs (above)** | | | | | | | | | | - |
| | **Inventory W / O** | | | | | | | | | | - |
| | **Spare Parts in Invent** | | | | | | | | | | - |

| **Reviewed by:** | **(Date)** | **Approved by:** | **(Date)** |
|---|---|---|---|
| ROB HARNESS | July 21, 2011 | | 21-July 2011 |
| Perry Bowles<br>Project Manager | | John Stopar<br>Manager, IMS | |

## Fuel Channel Life Management Project 10 - 62444 (OM&A)
## & Spacer Retrieval Tool Project 28 - 66567 (Capital)
## Partial Release Business Case Summary N - BCS - 31100 - 10006 - R000

## ATTACHMENT "B" PROJECT VARIANCE ANALYSIS

Fuel Channel Life Management Project – OM&A Portion

| | $ 000's OM&A | LTD Dec 2010 | Total Project | | Variance | Comments |
|---|---|---|---|---|---|---|
| | | | Last BCS Aug 2010 | This BCS Aug 2011 | | |
| Scores Basis | Project Mgmnt & Support | [redacted] | [redacted] | [redacted] | [redacted] | See Note 1 |
| | Engineering | [redacted] | [redacted] | [redacted] | [redacted] | See Note 2 |
| | Procurement | | | | - | |
| | Construction | | | | - | |
| | Other | | | | - | |
| | | | | | - | |
| | Interest (Capital Project Only) | | | | - | |
| | **Project Costs (Scores Basis)** | [redacted] | [redacted] | [redacted] | [redacted] | |
| | General Contingency | [redacted] | [redacted] | [redacted] | [redacted] | |
| | Specific Contingency | [redacted] | [redacted] | [redacted] | [redacted] | |
| | **Project Costs ( Scores Basis)** | **8,172** | **26,998** | **39,930** | **12,932** | |

| | | | | | | |
|---|---|---|---|---|---|---|
| Other | **Removal Costs included above** | | | | - | |
| | **Inventory to be written off** | | | | - | |
| | **Spare Parts in Inventory** | | | | - | |

## Comments:

- Note 1:
  Additional Project Management funding required:
  - $3.4 Million for added new scope to oversee supporting projects (e.g. Gap and Spacer Retrieval Tooling), supporting activities, and to confirm integration of R&D work into surveillance programs.

- Note 2:
  Additional Engineering funding required:
  - $[redacted]Million for new funding to allow OPG to enter into negotiations with Bruce Power to obtain critical spacer degradation data for Darlington FFS demonstration through the Bruce Power SFCR project in 2012.
  - $4.5 Million for the added R&D to obtain CNSC concurrence based on 18 technical submissions per agreed CNSC Protocol.

## Annulus Spacer Retrieval Project – Capital Portion

| | $ 000's<br>OM&A | LTD<br>Dec<br>2010 | Total Project | | Variance | Comments |
|---|---|---|---|---|---|---|
| | | | Last BCS<br>Aug<br>2010 | This BCS<br>Aug<br>2011 | | |
| Scores Basis | Project Mgmnt & Support | | 278 | 128 | (150) | |
| | Engineering | | 400 | 50 | (350) | |
| | Procurement | | 300 | 725 | 425 | |
| | Construction | [redacted] | [redacted] | [redacted] | [redacted] | |
| | Other | [redacted] | [redacted] | [redacted] | [redacted] | Assigned for project close-out |
| | SAVH | [redacted] | [redacted] | [redacted] | [redacted] | |
| | | [redacted] | [redacted] | [redacted] | [redacted] | |
| | Interest (Capital Project Only) | [redacted] | [redacted] | [redacted] | [redacted] | |
| | **Project Costs (Scores Basis)** | [redacted] | [redacted] | [redacted] | [redacted] | |
| | General Contingency | [redacted] | [redacted] | [redacted] | [redacted] | |
| | Specific Contingency | [redacted] | [redacted] | [redacted] | [redacted] | |
| | **Project Costs ( Scores Basis)** | **-** | **3,166** | **3,166** | **-** | |

| | | | | | | |
|---|---|---|---|---|---|---|
| Other | **Removal Costs included above** | | | | - | |
| | **Inventory to be written off** | | | | - | |
| | **Spare Parts in Inventory** | | | | - | |

**Comments:**

The total project estimate has not changed since the last partial release. However, the funding allocation has been adjusted to allow for the procurement of the tool from an external vendor.

**Fuel Channel Life Management Project 10 - 62444 (OM&A)**
**& Spacer Retrieval Tool Project 28 - 66567 (Capital)**
**Partial Release Business Case Summary N - BCS - 31100 - 10006 - R000**

## ATTACHMENT "C" SCHEDULE

### Key Milestones

| Completion Date | Description |
|---|---|
| 31-Aug-12 | Full Release BCS submitted |
| 31-Aug-12 | COG Fuel Channel Joint Projects 4363 and 4299 (Experimental Work)Complete |
| 31-Dec-12 | High Confidence Statement based on improved technical basis reported |
| 31-Dec-12 | CNSC Protocol requirements are met |
| 31-Jun-13 | Support for Pickering license renewal process completed |
| 31-Dec-13 | Confirmation of IMS ASRT project completion |
| 31-Dec-14 | Support for Darlington license renewal process completed |
| 31-Dec-14 | Regulatory submission for application of new methodologies at Pickering and Darlington submitted to CNSC |
| 30-Jun-15 | Confirmation that LCMPs have been updated according to COG R&D results |
| 30-Jun-15 | Project Complete |
| | |

A Project Execution Plan (PEP) will be approved by 31-Oct-11

### In Service Declarations: (Capital only)

| Date | Description | $000's (Total = Project Cost incl contg) | % In Service (= 100%) |
|---|---|---|---|
| 15-Oct-12 | Spacer Retrieval Tool Report of Equipment in Service Issued | 3,166 | 100 |
| | | | |
| | | | |
| | | | |

### Comments:

## Risk Probabilities Chart

| Likelihood | Improbable | Unlikely | Possible | Likely | Probable |
|---|---|---|---|---|---|
| **Probability** | **<= 1 in 100** | **About 1 in 100** | **About 1 in 10** | **About 1 in 5** | **>= 3 in 4** |
| **Rank** | **1** | **2** | **3** | **4** | **5** |

## Risk Impact Chart

| Impact Rating | Financial | Project Schedule 12 month | Quality | Corporate Reputation | Regulatory / Legal | Health & Safety | Environment | Nuclear Safety |
|---|---|---|---|---|---|---|---|---|
| **5** | >80% of Total Project $ | > 90 day delay | Significant, unacceptable non-conformance requiring extensive rework | National and international adverse coverage or impacts | Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges OR Potential loss of operating licenses | Potential for fatality(s) | Spill or release causing immediate and extended impact with off-site impacts, e.g.:Clean-up costs > $15MCat. A spill (>55 pts) | Loss or serious degradation of a safety system |
| **4** | 30% - 80% of Total Project $ | 30 - 90 day delay | Unacceptable non-conformance requiring some rework, but not major | Long-term local or national impact | Legislative non-compliance with potential for fines, charges, and damages ORMajor degradation of reputation with regulatory bodies | Potential for life-threatening critical injury or permanent total disability, including occupational disease | Exceedances resulting in charges or Director's OrderCat. A spill (45 - 55 pts)Public complaints with OPG implications Explosion and/or major fire | Reduced effectiveness of a safety system |
| **3** | 15% - 30% of Total Project $ | 10 - 30 day delay | Non-conformance bordering design tolerances, potential to require rework | Major local impact or minor national impact.Minor local damage | Systematic non-compliance with potential for finesORPotential to cause strained relationship with regulator, increased surveillance and/or regulations | Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature | Cat. B spills Emission in exceedance of regulatory or legal limits Field orders or Amp's Public complaints with OPG implications Danger to health, life, or property | Reduced effectiveness of redundant safety system components |
| **2** | 5% - 15% of Total Project $ | 3 - 10 day delay | Acceptable non-conformance, within design tolerances, no rework required | Complaints from local officials / politicians | Systematic non-compliance with impacts to project scheduleORPossibility of regulatory / legal implications | Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker. | Cat. C spills - reportableAdministrative infractionsPublic Complaints with plant level implications | Impact on a safety support or safety related system |
| **1** | <5% of Total Project $ | < 3 day delay | Minimal impact on qualityRoutine non-conformance, can be easily dispositioned | Complaints from local public | Isolated non-complianceORRoutine approval / notification | No medical attention beyond first aid, no impairment to worker or complete recovery of worker | Administrative, non reportable eventsCat. C spills non-reportable and spills resulting from Acts of God | |

Filed: 2013-09-27
EB-2013-0321
Ex. F2-3-3
Attachment 1 Tab 9

**Business Case Summary**

# Liquid Relief Valve Modifications to Reduce Waterhammer 16 - 38933 (OM&A)
# Partial Release Business Case Summary D - BCS - 63310 - 10003 - R000

| Name / Title / Phone | Location | Action | Signature | Date |
|---|---|---|---|---|
| Dianne Gaine<br>Director, Darlington Projects<br>703-1330 | D08ES3 | Prepare BCS | Dianne Gaine | May 30/11 |
| Sandy Stock<br>Director, Station Engineering<br>703-7584 | D08ES3 | Review BCS | S.D. Stock | 31 May 2011 |
| Phil Smith<br>Director, Projects Design<br>702-5430 | P82-2 | Review BCS | | Jun 1/2011. |
| Randy Leavitt \ JAMIE LAWRIE DIRECTOR INVESTMENT MGT<br>VP, Nuclear Finance<br>702-5177 | P82-3-318 | Review BCS | R Leavitt | JUN 13/2011<br>June 13, 2011 |
| Stu Seedhouse<br>SVP, Darlington<br>703-7499 | D08ES3 | Submit BCS | | June 21/2011 |
| Wayne Robbins<br>Chief Nuclear Officer<br>702-5294 | P82-6A | Review BCS | Wayne Robbins | 2011-06-17 |
| Donn Hanbidge<br>SVP & Chief Financial Officer<br>400-2395 | TCH19F27 | Approve BCS | | 2011-07-05 |
| Tom Mitchell<br>President & CEO<br>400-2121 | TCH19A24 | Approve BCS | | 2011-07-08 |
| | | | | |
| Carolyn Sicard<br>Nuclear Investment Management<br>702-4082 | P82-3B6.2 | Return for Distribution | | |

# Liquid Relief Valve Modifications to Reduce Waterhammer 16 - 38933 (OM&A)
# Partial Release Business Case Summary D - BCS - 63310 - 10003 - R000

## 1/ RECOMMENDATION:

We recommend a Partial Release of an additional $8.282 Million OM&A to fund Detailed Engineering and facilitate a long lead material procurement contract for the design, testing, and fabrication of five (5) new Nuclear Class 1 LRV valves for the Darlington Liquid Relief Valve (LRV) Modification project. Approval of this request will bring the total to date funding to $10.876 Million including a contingency of [redacted] Million. The total project is estimated to cost $ 21.609 Million (including [redacted] Million contingency) with an estimated completion date of 12/31/2025

The Business Objective of this Regulatory project is to address long term valve and piping degradation due to valve induced waterhammer, and ensure valve, piping and pipe support stresses are within allowable limits for design basis transients in which the LRVs operate. Replacement of the LRVs will mitigate rapid opening and closing times and eliminate waterhammer effects, while maintaining overpressure protection requirements. Continued operation has been justified via the Discovery Issue Resolution Process (DIRP) and subsequent Discovery Issue Assessment NK38-DIA-00531-10002 issued in 2006, which defined the nuclear safety risk associated with pipe failure as a result of LRV induced water hammer. Routine LRV piping and support inspections during planned outages (supporting the DIRP) have been implemented to confirm structural integrity remains intact for continued operation of the Heat Transport System (HTS) until the replacement valves are installed. Additionally the Engineering Decision Making (EDM) process was invoked in 2010 to reconfirm the conclusions of the DIRP for continued safe operation to further quantify the DNGS Site Management Board (SMB) decision to defer the installation of the LRVs concurrent with refurbishment due to economic, nuclear safety, and personnel dose concerns. The EDM Committee concluded it is technically acceptable to defer LRV replacement until the Darlington refurbishment outages with the issuance of a decision memorandum, NK38-CORR-33100-0362965 and technical memorandum, NK38-CORR-33100-0363511. The OPG decision to defer the installation phase concurrent with refurbishment is contingent upon obtaining CNSC acceptance of this proposed strategy, which is expected before end of Q2 2011.

The following deliverables will be completed during this release:

1. Design, test, and procure the new LRVs,
2. Complete the Detailed Design by April 2014, and
3. Place the project in deferment until refurbishment detailed planning for the first unit is complete, and then remove the project from deferment in ~ 2015 to prepare the next Partial Release BCS for first unit installation.

Installation of the new LRVs will begin in first unit refurbishment outage (~2017) with project completion concurrent with completion of last unit refurbishment outage (~2024).

| $000's (incl contingency) | Type | LTD Dec 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Currently Released | Partial | 1,301 | | 1,056 | 264 | | | | | 2,621 |
| Adj to Current Release | Adjustments | (242) | 1,535 | (1,056) | (264) | | | | | (27) |
| Requested Now | Partial | | (565) | 3,008 | 2,873 | | 333 | | 2,633 | **8,282** |
| Future Funding Req'd | Full | | | | | | | | 10,733 | **10,733** |
| Total Project Costs | | **1,059** | **970** | **3,008** | **2,873** | **-** | **333** | **-** | **13,366** | **21,609** |
| Non Project Costs | | | | | | | | | | - |
| Grand Total | | **1,059** | **970** | **3,008** | **2,873** | **-** | **333** | **-** | **13,366** | **21,609** |
| **Investment Type**<br>**Regulatory** | | **Class**<br>**OM&A** | | **NPV**<br>**-$9.67M** | | | **IRR**<br>**N/A** | | **Discounted Payback**<br>**N/A** | |

Submitted By: (Date)

June 21/2011

Stu Seedhouse
SVP, Darlington

Financial Approval By: (Date)

July 5/2011

Donn Hanbidge
SVP and Chief Financial Officer

**(OAR Element 1.1 Project in Budget)**

Line Approval By: (Date)

2011-07-11

Tom Mitchell
President and CEO

## 2/ BACKGROUND & ISSUES:

To ensure overpressure protection of the Heat Transport System (HTS) Darlington NGS contains four 100% power actuated Liquid Relief Valves (LRVs) in each unit, two per loop sharing common piping. Each loop has been designed and instrumented for both valves to open simultaneously on high loop pressure.

During commissioning of Darlington, performance of the LRVs was identified as less than adequate. It was discovered that the opening force of the valve was only designed for zero power hot conditions, which was not adequate to overcome the operating conditions of the PHT system at full power nor was the high flow rates due to the large differential pressure across the valve accounted for. Modifications were completed in two stages. This first stage involved installing larger tubing to allow more rapid depressurization of the air operated actuator to increase the valve opening speed. The second stage involved modification to the pilot plug and the pilot holes to provide larger flow capability and faster depressurization of the top of the main plug under hot conditions. The LRVs were also instrumented with displacement and force transducers to measure the valve stem movement and the actuator force. Following the changes, LRV performance was monitored to demonstrate availability and acceptable operation. Based on data recorded, Darlington LRVs are opening and closing faster than that assumed in the original design basis. This condition of fast opening/closing of the LRVs has the potential for higher than designed waterhammer load on the HTS piping.

In the event of an extremely rare set of circumstances occurring (i.e. design basis transients in which LRVs operate simultaneously), OPG is unable to definitively demonstrate that pipe and support stresses are within ASME code allowable limits, as is required by the Operating License, and is therefore unable to prepare and certify an Analysis of Record. However, on-going inspection of the HTS piping system has found no sign of pipe or support degradation. Additionally, as required by N-PROC-RA-0094, a DIRP was used to define the nuclear safety risk associated with pipe failure as the result of LRV induced waterhammer. The DIRP assessment (NK38-DIA-00531-10002) concludes that continued operation of the units until the modifications are installed is acceptable because the risk of pipe failure remains very low and the consequences are bounded by the existing safety report.

In addition, the Engineering Decision Making (EDM) process was invoked in 2010 to reconfirm the conclusions of the DIRP for continued safe operation to further quantify the DNGS Site Management Board (SMB) decision to defer the installation of the LRVs concurrent with refurbishment due to economic, nuclear safety, and personnel dose concerns. The EDM Committee concluded it is technically acceptable to defer LRV replacement until the Darlington refurbishment outages with the issuance of a decision memorandum, NK38-CORR-33100-0362965 and technical memorandum, NK38-CORR-33100-0363511. The economic, nuclear safety, and personnel dose concerns are reduced significantly by completing installation and commissioning during refurbishment since the HTS will be drained. Specifically, the economic impact is in the range of \$64M - \$93M if this project was installed and commissioned during regular unit outages due to the estimated critical path extension impact, which is 46 (up to 66) days total. Furthermore, the SMB and EDM Committee agreed that design and procurement of the LRVs must be completed now (and not delayed any further) to mitigate the risk of potentially needing to advance the installation schedule if signs of pipe or support degradation is found during regularly scheduled inspections.

The adopted solution is to replace the existing LRVs with new LRVs which will address the valve opening and closing times to mitigate undesirable waterhammer effects while maintaining overpressure protection requirements. Based on operating experience (OPEX), demonstrated through modifications at Cernavoda B, Wolsung, and Quinshan, this will resolve the existing potential waterhammer problem associated with LRV operation. Additionally, the LRV warming line will be relocated. The present location of the warming line for the current LRV is too far away to maintain the fluid temperature upstream of the valve. Field measurement has indicated the fluid temperature at the inlet to the LRV is substantially lower than the design basis and as such the stainless steel to carbon steel weld upstream of the valve will be subjected to a much higher thermal transient when the LRV is lifted. This could lead to premature fatigue failure at the transition weld. The purpose of the relocation of the warming line is to reduce (as far as practicable) the local thermal fatiguing that is occurring near the LRV inlet due to geometry of the current warming line connection point, and the presence of the resulting cooler water dead leg. Qualification/performance testing of the new valve by an external vendor will be performed to confirm elimination of waterhammer due to valve operation.

In February 2009, OPG submitted the proposed two-part strategy to resolve the LRV waterhammer issue (NK38-CORR-0053-14465) to the CNSC, thus closing out REGM AR 28082043. Part 1 includes removal of the existing LRVs and local piping to the LRVs and replacement with new “flow to open” LRVs. Part 2 involves implementing an inspection process appropriately suited for on-going validation of the pressure boundary integrity of the existing HTS piping and supports. After two rounds of correspondence requesting additional information and clarifications the CNSC responded in June 2010 that the CNSC agrees, in principle, to the proposed strategy however a new Action Item 28116373 was opened to track the completion of OPG undertakings as described in NK38-CORR-00531-15055. Quarterly meetings with the CNSC have been implemented and will continue on a regular basis until all issues are resolved.

A Value Engineering session was conducted during the Conceptual Phase to identify a short list of key project strategies and associated risks. These strategies were later explored in greater detail to define the Preferred Alternative.

A total of sixteen (16) Nuclear Class 1 valve / actuator sets and commissioning spares will be purchased, and an additional one (1) Non-Nuclear Class valve will be purchased and subjected to full qualification testing. Since the removed valves will be highly contaminated and their remaining life difficult to quantify, the valves have no salvage value.

Funding released by this BCS will be used to complete detailed design, perform an independent review of detailed design, perform extensive modeling, hydraulic, and stress analysis by a Design Agency, procure long lead materials (5 LRVs), qualification/seismic/performance testing of one (1) non-nuclear class valve, and preparation of the next Partial Release BCS.

## 3/ ALTERNATIVES & ECONOMIC ANALYSIS:

| $ 000's | Base Case | Alt 1 (Recommended) |  | Alt 2 | Alt 3 | Alt 4 | Alt 5 |
|---|---|---|---|---|---|---|---|
|  |  | Full Cost | Incremental Cost |  |  |  |  |
| **Revenue** |  |  |  |  |  |  |  |
| Base OM&A |  |  |  |  |  |  |  |
| Outage OM&A |  |  |  |  |  |  |  |
| Project OM&A |  | (21,610) | (20,334) |  |  |  |  |
| **Total OM&A** | 0 | (21,610) | (20,334) | 0 | 0 | 0 | 0 |
| **Capital** |  |  |  |  |  |  |  |
| **Present Value (PV)** |  | (10,567) | (9,674) |  |  |  |  |
| **Net Present Value (NPV)** | **N/A** | **(10,567)** | **(9,674)** |  |  |  |  |
| Internal Rate of Return (IRR) % | N/A |  |  |  |  |  |  |
| Discounted Payback (Yrs) | N/A |  |  |  |  |  |  |

### Base Case: × *Not Recommended -* Status Quo

This alternative is not recommended as OPG is unable to definitively demonstrate that pipe and support stresses are within ASME code allowable limits, as is required by the Operating License, and is therefore unable to prepare and certify an Analysis of Record. This does not satisfy the requirement for a long term solution to address operating outside of ASME code, as required by Discovery Issue Resolution Process N-PROC-RA-0094 Table 3, per the assessed conclusions of DIRP NK38-DIA-00531-10002. Thus this option has not been financially evaluated.

### Alternative 1: ✓ *Recommended* - LRV Replacement

Based on OPEX (operating experience), valve replacement (with flow to open design) will reduce the waterhammer problem associated with the LRV operation to an acceptable level. This has been demonstrated through modification at Cernavoda B and installation of new valves at Wolsung and Quinshan. In addition to the OPEX on flow to open design, replacing the valve will also allow relocation of the warming line to keep the valve warm as postulated in the original design basis. The new valves/actuators will be ordered with reducers and piping spools attached to minimize installation time.

### Alternative 2: × *Not Recommended -* Delay Project

Installation is presently scheduled to start in Refurbishment (~2017). Delaying any further is not recommended since the possibility of a HT piping failure could increase, and the CNSC may direct OPG to take action to mitigate the water hammer problem if a further delay is imposed. Thus this option has not been financially evaluated.

**Alternative 3:** × *Not Recommended -* **Minor Modifications to the LRV/Actuator**

This alternative is not recommended considering the minor modification will not completely eliminate the waterhammer problem. This is due to the fact that the present set up of the LRVs makes it difficult to control or to predict the valve behavior. Thus this option has not been financially evaluated.

**Alternative 4:** × *Not Recommended -* **Reversal of Existing Valve Body and Replacement of Trim, Valve, Internals, and Actuator**

This alternative is not recommended. Similar to the Recommended Option, OPEX indicates that reversal of the valve could correct the waterhammer problem. However, the existing valve internals, trim, and actuators would require replacement if the valves were reversed. Valve testing prior to installation is not possible. As a result, there are numerous uncertainties, reliability issues and a lack of confidence surrounding this option. Additionally, the remaining life of the valve bodies is difficult to quantify as they may have been subjected to waterhammer loads in the past. Thus this option has not been financially evaluated.

**Alternative 5:** × *Not Recommended -* **Perform Analysis to Demonstrate Piping Integrity**

After more than two years of analysis using both standard and non-standard methods of analysis, the piping designers concluded that the magnitude of waterhammer load in the event of an extremely rare set of circumstances occurring (under worst case scenario) would be unacceptably high and that stresses cannot be brought within ASME code allowable limits. Further analysis alone would not be beneficial. Therefore this is not a viable option. Thus this option has not been financially evaluated.

**Alternative 6:** × *Not Recommended -* **Replace all Potentially Over-Stressed Piping in Conjunction with Valve Alternative 1, 3, or 4**

Replacement of all affected HTS piping has not been demonstrated to be necessary at this time. This option is not recommended since the cost of undertaking such a large replacement of the HTS piping would be extremely high and require extensive time to install. Thus this option has not been financially evaluated.

## 4/ THE PROPOSAL

Major activities completed under the previous Developmental and Partial BCS Releases included the following:

1) Valve tendering specification was submitted and a budgetary estimate for valve procurement was received,
2) Preliminary design was completed and preliminary LRV opening/closing limits were established,
3) Valve design technical specification was issued,
4) Modeling, hydraulic/stress analysis Scope of Work was issued,
5) Two (2) Request For Proposals (RFPs) were issued and successful proponents selected for:
    a. Valve procurement, and
    b. Modeling, hydraulic and stress analysis.
6) 3rd Party Independent Technical Review of “Darlington Technical Position on Primary Heat Transport Liquid Relief Valve Piping was completed and report NK38-REP-33100-10028 issued,
7) Measurements of the HTS piping associated with the waterhammer issues were collected from each unit during the DNGS VBO,
8) Front End Planning was completed, and
9) PEP NK38-PEP-63310-03364450 was approved.

The Scope of Work proposed under this Partial Release BCS release is summarized below:

1) Project Management:
    *a.* Project Administration
    *b.* Project Reporting – Schedule, Cost, Risk
    *c.* Design Agency & Valve vendor Contract Management
    *d.* CNSC Updates

2) Project Management Office:
    *a.* Project Reporting – Schedule, Cost, Risk

3) Partial Release (for 1st Unit Installation):
    *a.* Business Case Summary
    *b.* Basis of Estimate
    *c.* Risk Management Plan
    *d.* Project Execution Plan

4) Installation Contract:
    a. SOW
    b. Issue RFP
    c. Bid Evaluation

5) OPG Design:
    *a.* Design Agency deliverables review and acceptance
    *b.* Valve Vendor review and acceptance
    *c.* Mechanical Design EC
    *d.* Civil Design EC
    *e.* I&C Design EC
    *f.* Over Pressure Report
    *g.* Final Thrust Calculation
    *h.* ASME Section XI Fatigue Analysis
    *i.* Independent Design Review
    *j.* CNSC Acceptance
    *k.* TSSA Registration/Reconciliation

6) Design Agency Contract – Certified Hydraulic & Stress Analysis Report

7) Valve Manufacturer Contract – Design & delivery of 5 Class 1 LRV Valves and 1 Commercial Test Valve for OPG Training Department

***Future BCS Releases will facilitate installation activities in Darlington four (4) units concurrent with refurbishment outages***.

## 5/ QUALITATIVE FACTORS

The successful completion of this project will address the following:

1) Establish acceptable limits for LRV opening and closing operation.
2) Confirm that valve operation effectively reduces waterhammer to acceptable levels.
3) Maintain Station Operating License.
4) Satisfy regulatory issues.
5) Decrease risk of piping failure.
6) Decrease the rate of equipment aging due to fatigue which could potentially impact on plant life extension.

## 6/ RISKS ANALYSIS (See Attachment D for details)

| Low<br>1 to 3 | Medium<br>4 to 9 | High<br>10 to 25 |
|---|---|---|

| | | Impact | | | | |
|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 |
| Probability | 5 | 5 | 10 | 15 | 20 | 25 |
| | 4 | 4 | 8 | 12 | 16 | 20 |
| | 3 | 3 | 6 | 9 | 12 | 15 |
| | 2 | 2 | 4 | 6 | 8 | 10 |
| | 1 | 1 | 2 | 3 | 4 | 5 |

| Risk Description | Mitigating Activities | Mitigation | Probability X Impact<br>Finance | Schedule | Quality | Corporate Reputation | Regulatory | Health & Safety | Environmental | Nuclear Safety | Risk Rating (1 to 25) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Original valve manufacturer selected withdrew their proposal and is no longer willing to supply the valves due to the Fukushima event. Second preferred valve vendor is being pursued. Long Lead Material PO may not be awarded as per Project Schedule due to second preferred valve vendor not possessing proper C of A for Class G valves. New RFP may be required due to C of A issue. | Projects, Design and Supply Chain is working with the second preferred valve vendor to resolve the C of A issue to avoid the need for another RFP which would delay the project by approx. 4 months. | Before | 5 | 20 | | | | | | | 20 |
| | | After | 4 | 10 | | | | | | | 10 |
| Cost for Performance and Certification valve testing is higher than anticipated. (i.e. Test Facility may have to be rescheduled due to delays) | 1. Design to clarify testing requirements with vendor as actioned in PO pre-award meeting. (complete)<br>2. Design to issue Valve Tech Spec R01. (complete)<br>3. Issue new RFP to proponents and obtain updated, confirmed pricing from vendors.<br>4. Update BCS to change funding required.<br>5. Build some contingency time into the schedule to allow for delays. | Before | 9 | | | | | | | | 9 |
| | | After | 1 | | | | | | | | 1 |
| Long Lead Material - Valve procurement cost exceeds contract due to:<br>1) specification changes required as a result of factory testing<br>2) OPG Model Analysis results<br>3) Cost of C of A equivalency exceeds estimate | 1. Extensive technical meetings held with preferred vendor to establish minimal required testing, which was incorporated into the Design Specification. (Complete)<br>2. Selected proponent proposal costs incorporated into this release estimate.<br>3. Risk identified and contingency funding allotted in Risk Management Plan. | Before | 12 | | | | | | | | 12 |
| | | After | 4 | | | | | | | | 4 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Long Lead Material Contract & LRV Procurement Canadian cost goes up due to US exchange rate fluctuation | Add contingency for US exchange rate fluctuations. | **Before** | 12 | | | | | | | | 12 |
| | | **After** | 6 | | | | | | | | 6 |
| Risk of CNSC not accepting OPG adopted strategy to complete design but defer installation concurrent with refurbishment. | 1. EDM quorum to provide concurrence on DNGS SMB recommendation for installation deferral to Refurbishment before submission to CNSC. (Complete)<br>2. Strategy to be communicated to CNSC informally via quarterly update to obtain initial feedback.<br>3. Solid Technical justification to be submitted to CNSC. | **Before** | 6 | 12 | | | 6 | | | | 12 |
| | | **After** | 4 | 8 | | | 4 | | | | 8 |
| Project Installation schedule advanced due to CNSC direction or pipe failure in DN units. | 1. Formal letter submitted to CNSC for concurrence with installation in Refurbishment.<br>2. EDM quorum validated the DIRP through Refurbishment period and agreed that it is safe to operate until Refurbishment with a very low risk of pipe failure. | **Before** | 9 | | | | 8 | | | 5 | 9 |
| | | **After** | 3 | | | | 2 | | | 3 | 3 |
| Final Analysis on models identifies valve opening/closing time to be unacceptable after performance testing of commercial test valve is already complete. | 1. Engineering Services to perform scoping modeling runs to assess reduction in waterhammer loads with preliminary valve design provided by Vendor. Confirm new valve design is acceptable. (Complete)<br>2. Confirmation of valve weight and computer generated Cv curve to be requested from vendor on PO issue. | **Before** | 4 | 16 | | | | | | | 16 |
| | | **After** | 2 | 8 | | | | | | | 8 |

## Liquid Relief Valve Modifications to Reduce Waterhammer 16 - 38933 (OM&A)
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|---|---|---|---|---|---|---|---|---|---|---|---|
| Delay in material fabrication and/or delivery by vendors. (New valve lead time may be excessive or delayed) | 1. Maintain communication/coordination with vendor and expedite when necessary.<br>2. Place long lead material PO's early, and expedite as required. Place order for valves well in advance of required delivery date. (Vendor has identified 52 weeks lead time)<br>3. Examine Flow Diagram changes - materials, elbow tap vs. valve tap.<br>4. CNSC agreement required - obtain during Detailed Design.<br>5. Allow adequate time for Design to implement any changes.<br>6. Monthly update meetings with Vendor.<br>7. Obtain vendor Schedule for deliverables.<br>8. Expedite OPG turnaround time. | **Before** | | 20 | | | | | | | 20 |
| | | **After** | | 6 | | | | | | | 6 |
| Long Lead Material PO or Design Agency PO not awarded as per Project Schedule. (i.e. New RFP is required due to NV/C of A issues) | 1. Work with Supply Chain & Design to expedite.<br>2. Obtain Testing requirements and revise Tech Spec and SOW. (Complete)<br>3. Finalize Terms & Conditions. | **Before** | | 12 | | | | | | | 12 |
| | | **After** | | 4 | | | | | | | 4 |
| OPG Detailed Design/Analysis takes longer than anticipated to complete. Specific factors which may contribute to this are additional failure modes identified during model runs and/or changes to the piping technical specification.<br>Note: Residual risk was still rated high due to the potential possibility of more than one modeling run iteration being required during the detailed hydraulic and stress analysis to mitigate emergent model identified issues. | 1. Ensure resourcing and schedule durations are provided and agreed to by support groups, vendor, and design agency.<br>2. Expedite required vendor and design agency information.<br>3. Coordinate schedule between OPG, vendor, and design agency to meet Design milestones. | **Before** | 10 | 20 | | | | | | | 20 |
| | | **After** | 8 | 12 | | | | | | | 12 |

## Liquid Relief Valve Modifications to Reduce Waterhammer 16 - 38933 (OM&A)
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|---|---|---|---|---|---|---|---|---|---|---|---|
| Design EC's not issued per schedule | 1. Expedite valve manufacturing and testing.<br>2. Coordination with all workgroups to ensure schedule and milestones are met.<br>3. CNSC concurrence of project scope to expedite design concessions at end of Detailed Design Phase. | **Before** | 4 | 16 | | | | | | | 16 |
| | | **After** | 2 | 8 | | | | | | | 8 |
| Mitigation of any concerns identified by Independent Design review takes longer than originally anticipated. | Design to engage Independent Reviewer early in Detailed Design and submit documentation/models for review as it is available. | **Before** | 3 | 12 | | | | | | | 12 |
| | | **After** | 2 | 8 | | | | | | | 8 |
| Valve testing or contract deliverables are not submitted/completed as per schedule and/or initial test results may not meet standards or technical requirements.<br>Note: Residual risk was still rated high based on OPEX identified by Supply Chain on selected valve vendor timeliness issues on several recent contracts. | 1. Testing is to be completed as part of PO for valves.<br>2. Expedite valve testing.<br>3. Expedite OPG drawing & Inspection & Test Plan (ITP) acceptance turnaround time.<br>4. Confirm testing schedule with vendor. | **Before** | 8 | 20 | 20 | | | | | | 20 |
| | | **After** | 6 | 15 | 15 | | | | | | 15 |
| External stakeholders (TSSA, CNSC) require re-registration of HTS to maintain operating license.<br>Note: Re-registration of the HTS may be required if CNSC/TSSA invokes ASME Section III analysis requirements on this project. However, ASME Section III analysis cannot be completed unless the entire HTS is replaced (including all piping). | Communications with CNSC have resulted in a formal agreement in principle of invoking ASME Section XI analysis instead of ASME Section III analysis to finalize the detailed design. (Ref: NK38-CORR-00531-15146) | **Before** | 12 | 15 | | | 9 | | | | 15 |
| | | **After** | 2 | 4 | | | 2 | | | | 4 |
| Modifications to LRVs exceed seismic weight limitations - piping analysis requires downstream pipe/support changes. | Complete analysis during Detailed Design Phase to ensure weights acceptable. | **Before** | 2 | 10 | 6 | | | | | | 10 |
| | | **After** | 1 | 2 | 1 | | | | | | 2 |
| Valves and actuators may not physically fit | 1. Conduct detailed walkdown (including drawing confirmation) during D1041 / D1021. Field measurements will be taken. (Complete)<br>2. Vendor will supply final dimensions of new valve and actuator Q3 2011.<br>3. Potential use of mock-up (included in contingency). | **Before** | | 12 | 9 | | | | | | 12 |
| | | **After** | | 4 | 4 | | | | | | 4 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Risk of additional failure modes | 1. Examine Darlington Probability Risk Assessment in Detailed Design.<br>2. Collect additional OPEX from other stations and vendor. (Complete)<br>3. Complete modeling during detailed design phase. | **Before** | 2 | 5 | 5 | | | | | | 5 |
| | | **After** | 1 | 2 | 2 | | | | | | 2 |
| Lack of Senior Designers with extensive Nuclear Class 1 experience and/or Engineering Mechanics Modeling Experience to review Design Agency deliverables.<br>- Review of stress analysis takes longer than originally anticipated by ES.<br>Note: Residual risk is still rated as high because:<br>- Review will stop on models/analysis by ES if forced outage occurs in Darlington/Pickering.<br>- Valve test results are not what is expected. Large impact on modeling may occur during last modeling runs. | 1. Contract out Modeling and Stress/Hydraulic Analysis to an External Design Agency with extensive knowledge to support Design and Modeling Runs throughout Detailed Design. (RFP sent to two qualified External Design Agencies.)<br>2. Get commitment from ES for review of Design Agency Deliverables. | **Before** | 3 | 15 | | | | | | | 15 |
| | | **After** | 2 | 10 | | | | | | | 10 |
| Code Effective Date (CED) to allow installation through last unit in Refurb (~ 2023) using design completed in April 2014 not approved by CNSC.<br><br>Ability to invoke N-PROC-MP-0090 rev 006 for LRV execution thru 2023 not approved by site DA. | 1. After refurbishment CED is established and accepted by the CNSC, our project will request formal CNSC concurrence for CED.<br><br>2. Request DA approval for use of N-PROC-MP-0090 rev 006 thru to 2023 following CED acceptance by CNSC. | **Before** | 5 | 5 | | | 5 | | | | 5 |
| | | **After** | 2 | 2 | | | 2 | | | | 2 |
| Reconciliation of Design from 2007/2008 Code Effective Date (CED) to Refurbishment CNSC accepted CED may be required. | 1. Follow-up with Refurbishment organization to stay informed on CED issue.<br>2. After refurbishment CED is established and accepted by the CNSC, request the Design Agency to reconcile the hydraulic and stress analysis from 2007/2008 to said CNSC accepted CED. | **Before** | 5 | 12 | | | | | | | 12 |
| | | **After** | 5 | 9 | | | | | | | 9 |
| Darlington Plant Design SME cannot support the review of project deliverables on time. | Get commitment from Plant Design to meet the scheduled completion dates for project deliverables | **Before** | | 12 | | | | | | | 12 |
| | | **After** | | 4 | | | | | | | 4 |

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EB-2013-0321
Ex. F2-3-3
Attachment 1 Tab 9

## Liquid Relief Valve Modifications to Reduce Waterhammer 16 - 38933 (OM&A)
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|---|---|---|---|---|---|---|---|---|---|---|---|
| The LRV warming lines stress analysis fail in the initial detailed runs.<br>Note: Residual risk was still rated high based on the warming line stress analysis failing during the scoping runs completed by OPG Engineering Services. | The SOW and Piping TS is written such that the Design Agency is responsible for re-designing these lines, if required. | **Before** | 10 | 15 | | | | | | | 15 |
| | | **After** | 8 | 12 | | | | | | | 12 |
| Qualification of software required to complete modeling analysis. | Project will give preference to Design Agency with already qualified STANPIPES and PTRAN software programs, per evaluation criteria. | **Before** | | | 10 | | | | | | 10 |
| | | **After** | | | 2 | | | | | | 2 |
| Valve vendor does not have a design with a ~linear Cv vs Flow curve (as acceptable by OPG) for both valve opening and valve closing. | OPG Design to verify that Cv vs Flow curve provided by valve vendor is acceptable. | **Before** | | | 12 | | | | | | 12 |
| | | **After** | | | 4 | | | | | | 4 |
| Installed and Approved ECs and other data are missing from piping models for either Unit 1, 2, 3, or 4. i.e. Discrepancies between drawings and models. | SOW and Piping Design Specification is written in such a way that the Design Agency is responsible to disposition these discrepancies without delaying to the completion of the deliverables. (Complete)<br>Three memos were approved by Design outlining the discrepancies in the systems (PHT, PI&C, SDC). (Complete) | **Before** | | | 9 | | | | | | 9 |
| | | **After** | | | 3 | | | | | | 3 |
| No Engineering Services resources available for Nozzle re-qualification (analysis). | Projects and Design to get commitment from ES to complete nozzle qualification. | **Before** | 12 | 9 | | | | | | | 12 |
| | | **After** | 4 | 4 | | | | | | | 4 |
| **Future Releases** | | | | | | | | | | | |
| Material procurement cost exceed initial material estimates (including NC1 pipe and elbow costs, and bungs) | 1. Expedite DBOM into earlier phase of design.<br>2. Order materials in 2012 (for D1321) or 2015 (for Refurb). | **Before** | 6 | | | | | | | | 6 |
| | | **After** | 4 | | | | | | | | 4 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Risk of increased inventory costs | 1. Get spare parts list from vendor.<br>2. Finalize inventory with maintenance SPOC.<br>3. Spare parts will be procured and reorder point specified to ensure adequate stock on site. | **Before** | 6 | | | | | | | | 6 |
| | | **After** | 4 | | | | | | | | 4 |
| Discovery work and/or rework is required during installation | 1. Conduct detailed walkdown (including drawing confirmation) during VBO & D1041. (complete)<br>2. Ensure scope adequately captured to mitigate possibility, and allot contingency for discovery work.<br>3. Work closely with CMO and station support to capture potential surprises in advance.<br>4. Examine possibility of constructing mock-up for rehearsal.<br>5. Qualified workers will be hired for the job and adequate training will be conducted. | **Before** | 6 | 9 | | | | | | | 9 |
| | | **After** | 4 | 6 | | | | | | | 6 |
| Replacement parts may not be readily available | 1. Tech Specs require vendor to identify spare parts.<br>2. Procure replacement parts with valves and ensure reorder points are identified in advance.<br>3. Design to prepare EBOM. | **Before** | | 9 | | | | | | | 9 |
| | | **After** | | 6 | | | | | | | 6 |
| Execution window exceeds Outage window | 1. Conduct detailed walkdown (including drawing confirmation) during D1041. (complete)<br>2. Adequate preparations and pre-fabrication to meet outage window.<br>3. Present to SMB recommended solution - deferral to Refurbishment (2016~2023) (complete)<br>4. Get CNSC concurrence with path forward strategy (deferral to Refurbishment) | **Before** | 15 | 20 | | | | | | | 20 |
| | | **After** | 3 | 3 | | | | | | | 3 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Delay in material fabrication and/or delivery by vendors. (New valve lead time may be excessive or delayed)<br>Note: Residual risk was still rated high based on OPEX identified by Supply Chain on selected valve vendor timeliness issues on several recent contracts. | 1. Maintain communication/coordination with vendor and expedite when necessary.<br>2. Place long lead material PO's early, and expedite as required.<br>3. Examine Flow Diagram changes - materials, elbow tap vs. valve tap.<br>4. CNSC agreement required - obtain during Detailed Design. | **Before** | | 16 | | | | | | | 16 |
| | | **After** | | 12 | | | | | | | 12 |
| Station delays may impact installation progress via:<br>- station resources are not available,<br>- poor communication and hand offs,<br>- potential delays if permits are not issued on time. | 1. Identify requirements and interfaces with Station well in advance. Work plan will identify interface requirements. Station will review and sign. Tasks will be scheduled.<br>2. Notify Station of upcoming work and proposed Outage/Refurb windows in advanced to ensure adequate support available.<br>3. Obtain commitments in advance.<br>4. Prepare commissioning plan, prepare logic with handoffs identified.<br>5. Hold project meetings with all work groups.<br>6. Follow Outage/Refurb schedule processes (prepare permits in advance).<br>7. Follow up with stakeholders, as required. | **Before** | | 8 | | | | | | | 8 |
| | | **After** | | 4 | | | | | | | 4 |
| The unique valve design may strain existing resources:<br>- additional training and qualifications,<br>- new valve may require additional maintenance. | 1. Give conventional valve to OPG Maintenance for training purposes.<br>2. Complete a training assessment to identify requirements for training and qualifications.<br>3. Prepare documents and align resources to conduct training.<br>4. Design to minimize maintenance. | **Before** | 3 | 6 | | | | | | | 6 |
| | | **After** | 2 | 4 | | | | | | | 4 |
| Qualified contractor personnel are not available to perform the work | Contractor should be in contact with Union Hall well in advance. Identify critical nature of this job in the contract. | **Before** | | 9 | | | | | | | 9 |
| | | **After** | | 3 | | | | | | | 3 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High dose rates require additional contractor staff to complete the work | 1. Conduct detailed walkdown with H&S Rep during VBO to discuss potential issues. (complete)<br>2. ALARA principle will be used. Training will ensure minimum unplanned dose.<br>3. Potential use of mock up.<br>4. Obtain historic dose rates from RP.<br>5. Ensure adequate workers hired. | **Before** | 4 | | | | | | | | 4 |
| | | **After** | 3 | | | | | | | | 3 |
| LRV's are located in congested space. Therefore, during installation, there is a potential for Health and Safety issues to arise as employees are exposed to hazards. Accessibility around the valves may be more limited. | 1. Conduct detailed walkdown (including drawing confirmation) during D1041. (complete)<br>2. Prepare Human Factors forms to identify and address concerns<br>3. Current processes and procedures will be followed (event free tools, etc.)<br>4. Potential use of mock up. | **Before** | | | | | | 9 | | | 9 |
| | | **After** | | | | | | 3 | | | 3 |
| Issues encountered with valve following installation. | Spare NC1 valve to be procured. Spare parts for commissioning to be procured. | **Before** | | | 9 | | | | | | 9 |
| | | **After** | | | 6 | | | | | | 6 |
| New valves may:<br>- be more prone to passing (leakage),<br>- be less reliable (open/close),<br>- not accommodate routine testing. | 1. Collect additional OPEX from other stations and vendor.<br>2. Tech Spec includes seat leakage requirements.<br>3. To be verified during valve testing.<br>4. To be analyzed during Detailed Design. | **Before** | | | 6 | | | | | | 6 |
| | | **After** | | | 4 | | | | | | 4 |
| Temporary installation conditions may require excessive analysis (eg. Slinging, Jacking/Spreading) | Assessments will be complete by EMD (or Design Agency - Managed Task) to identify requirements well in advance. | **Before** | 6 | 9 | | | | | | | 9 |
| | | **After** | 4 | 6 | | | | | | | 6 |

## 7/ POST IMPLEMENTATION REVIEW

| Type of PIR: | Targeted Final AFS Date: | Targeted PIR Approval Date | PIR Responsibility (Sponsor Title) |
|---|---|---|---|
| **Simplified** | **29-Dec-23** | **31-Dec-25** | **Director, Station Engineering** |

| | Measurable Parameter | Current Baseline | Targeted Result | How will it be measured? | Who will measure Person / Group? |
|---|---|---|---|---|---|
| 1. | Acceptable LRV opening and closing limits established. | Current opening / closing time is < 0.05 seconds | Opening / closing times between 1.0-3.0 seconds | Through valve/actuator testing and commissioning following each unit's installation | Vendor / Contractor / MC |
| 2. | Confirm by analysis that valve operation effectively reduces waterhammer to acceptable levels under all design basis events for which the LRVs are called to operate, with consideration to the full range of design and operating conditions. | Cannot be demonstrated that piping meets ASME Section III stress and fatigue limits under all design basis events for which the LRVs are called to operate, with consideration to the full range of design and operating conditions. | Perform ASME Section XI flaw tolerance evaluation to demonstrate piping condition is acceptable under all design basis events for which the LRVs are called to operate, with consideration to the full range of design and operating conditions. | Hydraulic and Stress Analysis modeling to be used as input into Section XI analysis, to be completed during Detailed Design Phase. | Design Agency / OPG Engineering Services / Projects Design |
| 3. | Outage inspections of piping and support. | Piping and supports are inspected every planned outage | Reduce number of inspections to every 2nd or 3rd planned outage per inspection | Reduced inspection frequency as derived by Engineering Services per ASME Section XI. | OPG Engineering Services / Projects Design |
| 4. | Relocation of LRV warming line to mitigate large temperature gradient (as high as 80°C) condition upstream of LRVs due to stagnant fluid. | Current LRV warming line is located on the vertical run of pipe upstream of the LRVs. Due to this configuration, a portion of fluid immediately upstream of the LRVs remains stagnant and cools due to natural convection. | By relocating LRV warming line closer to LRVs with the connection to the horizontal run, fluid will circulate this dead leg region and ensure temperature gradient does not develop. | Temperature will be measured immediately upstream of the LRV inlet and compared with temperature measured at a location further upstream. Temperature measurements are expected to be within 20°C. | Vendor / Contractor / MC |

## APPENDIX “A’ GLOSSARY (acronyms, codes, technical terms)

| | |
|---|---|
| ASME | American Society of Mechanical Engineers |
| BCS | Business Case Summary |
| CNSC | Canadian Nuclear Safety Commission |
| CED | Code Effective Date |
| DIRP | Discovery Issue Resolution Process |
| HT | Heat Transport |
| HTS | Heat transport System |
| LRV | Liquid Relief Valve |
| TBD | To Be Determined |
| PEP | Project Execution Plan |
| SMB | Site Management Board |
| EDM | Engineering Decision Meeting |
| OPEX | Operating Experience |
| ITP | Inspection and Test Plan |
| SOW | Scope of Work |
| ES | Engineering Services |

## APPENDIX “B” Comparison of Total Project Estimates

| $ 000's | | This Appendix compares the Total Project Estimate for each BCS | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | *Total Project Estimate* (by Year incl Contingency) | | | | | | | | | Total Project |
| BCS Type | Class | Mth | Yr | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | Later | Est |
| Developmental | OM&A | Dec | 2008 | 680 | 1,090 | 528 | 3,528 | 6,966 | 3,606 | | | 16,398 |
| Partial | OM&A | Oct | 2009 | 550 | 1,651 | 444 | 3,127 | 5,682 | 2,989 | | | 14,443 |
| Partial | OM&A | May | 2011 | 462 | 597 | 970 | 3,008 | 2,873 | | 333 | 13,366 | 21,609 |
| | | | | | | | | | | | | 0 |
| | | | | | | | | | | | | 0 |
| | | | | | | | | | | | | 0 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LTD Spent | OM&A | Apr | 2011 | 462 | 597 | 217 | | | | | | 1,276 |
| LTD Spent | | | | | | | | | | | | 0 |
| LTD Spent | | | | | | | | | | | | 0 |

**Comments:**

## APPENDIX "C" FINANCIAL MODEL – ASSUMPTIONS

### Financial Assumptions:

| | | | | | |
|---|---|---|---|---|---|
| Discount Rate: | 7% | Cost Escalation (Yr) | 2% | SR&D Opportunity | Yes |
| Progress Payments | No | Foreign Currency | Yes | Retainer Fee | No |
| Depreciation Rate (Capital) | N/A | PST | No | Interest Rate (Capital) | OM&A N/A |
| Revenue Rate | N/A | Leasing | No | Indexed Priced Contract | No |

**Comments:**

This Project has been classified as OM&A funding. Per Finance, 2% inflation rate was used for cost escalation for years 2016 to 2024.

### Project Cost Estimate:

| | | | | | |
|---|---|---|---|---|---|
| Design Complete: | Zero to Minimal | Fixed Price Contract | No | 3rd Party Estimate | Yes |
| Quality of Estimate | Budget +30% to -15% | OPEX used | Yes | Lessons Learned | No |
| Similar Projects | Yes | Budgetary Quote | Yes | First Unit Actual Used | N/A |
| Firm Vendor Proposal | Yes | Cost Sharing | No | Competitive Bid | Yes |
| Reviewed by Sponsor | Yes | Fee for Service | No | Contracts in place | No |

**Comments:**

A budgetary vendor proposal was received for the valve design, testing, and fabrication of five (5) Nuclear Class Valves. A budgetary estimate was received for the remaining eleven (11) Nuclear Class Valves. A firm vendor proposal was received for the modeling, hydraulic and stress analysis scope of work. Budgetary estimates were received for the installation & commissioning of the valves.

### Rationale for Capital Cost Classification:

N/A

### Generation Plan Assumptions:

| Station | Unit | EOL or Refurb | MW | Planned Outages for Project Work | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Pickering A | 1 | Jun-20 | 515 | | | | | | | |
| | 4 | Jun-20 | 515 | | | | | | | |
| Pickering B | 5 | Nov-18 | 516 | | | | | | | |
| | 6 | Nov-18 | 516 | | | | | | | |
| | 7 | Jun-20 | 516 | | | | | | | |
| | 8 | Jun-20 | 516 | | | | | | | |
| Darlington | 1 | Sep-16 | 878 | | | | | | | |
| | 2 | Feb-18 | 878 | | | | | | | |
| | 3 | Sep-19 | 878 | | | | | | | |
| | 4 | Jan-21 | 878 | | | | | | | |

**Comments:**

Installations will be completed during the following Refurbishment Outages:

- First Unit - ~ 2017
- Second Unit - ~ 2019
- Third Unit - ~ 2021
- Fourth Unit - ~ 2023

## APPENDIX "D" FINANCIAL MODEL – ASSUMPTIONS

### Impact on Operations

### NPV Assumptions

This is the complete set of assumptions used in the calculation of NPVs for the BCS, Part A and Part B.

Base Case

- As this is a Regulatory project, the Base Case option has not been financially evaluated, and thus the PV is, by default, zero.

Alt 1 Recommended Alternative

- The PV was arrived at by using a simple NPV calculation of the costs in the Project Cost Summary (Attachment A)

Alt 2 and all subsequent Alternatives - Not Recommended

- As none of these options would meet the regulatory requirements, they have not been financially evaluated.

## Liquid Relief Valve Modifications to Reduce Waterhammer 16 - 38933 (OM&A)
## Partial Release Business Case Summary D - BCS - 63310 - 10003 - R000

**APPENDIX “E”** ***PROJECT DELIVERABLES (for this release)***

| Item | Description | Deliverable | Cost ($000's) |
|---|---|---|---|
| 1 | Project Management | Project Administration | 539 |
| | | Project Reporting - Schedule, Cost, Risk | |
| | | DA & Valve Vendor Contract Management | |
| | | CNSC Updates | |
| 2 | Project Management Office | Project Reporting - Schedule, Cost, Risk | 98 |
| 3 | Partial Release | Business Case Summary | 38 |
| | | Basis of Estimate | |
| | | Risk Management Plan | |
| | | Project Execution Plan | |
| 4 | Installation Contract | SOW | 22 |
| | | Issue RFP | |
| | | Bid Evaluation | |
| 5 | OPG Design | DA deliverables review and acceptance | 670 |
| | | Valve Vendor review and acceptance | |
| | | Mechanical Design EC | |
| | | Civil Design EC | |
| | | I&C Design EC | |
| | | Over Pressure Report | |
| | | Final Thrust Calculation (ACE) | |
| | | ASME Section XI Fatigue Analysis | |
| | | Independent Design Review | |
| | | CNSC Design Acceptance | |
| | | TSSA Registration/Reconciliation | |
| 6 | Design Agency Contract | Certified Hydraulic & Stress Analysis Report | 2100 |
| 7 | Valve Manufacturer Contract | Design & Delivery of 5 Class 1 LRV Valves | [redacted] |
| 8 | Overheads | Training | [redacted] |
| | | Travel | [redacted] |
| | | Project Support Allocation | [redacted] |
| 9 | Contingency | | [redacted] |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| **Total** | | | **8,282** |

Filed: 2013-09-27
EB-2013-0321
Ex. F2-3-3
Attachment 1 Tab 9

# Liquid Relief Valve Modifications to Reduce Waterhammer 16 - 38933 (OM&A)
## Partial Release Business Case Summary D - BCS - 63310 - 10003 - R000

**ATTACHMENT "A"** **PROJECT COST SUMMARY**

| | $ 000's<br>OM&A | LTD Dec 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Accounting Basis | Project Mgmnt & Support | 319 | 358 | 364 | 365 | | 250 | | 1,400 | **3,056** |
| | Engineering | 690 | 452 | 679 | 505 | | 28 | | 301 | **2,655** |
| | Procurement | | | 630 | 270 | | | | 5,844 | **6,744** |
| | Construction | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Other | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Design Agency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Interest (Capital Project) | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Project Costs** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | General Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Specific Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Project Costs** | **1,059** | **970** | **3,008** | **2,873** | **-** | **333** | **-** | **13,366** | **21,609** |

| | $ 000's<br>OM&A | | LTD Dec 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Funding Basis | **Current Release** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Adj to Current Release** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **This Release** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **TTD Released** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Future Releases** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Project Funding** | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Contingency Funding** | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Total Funding** | | **1,059** | **970** | **3,008** | **2,873** | **-** | **333** | **-** | **13,366** | **21,609** |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Budget | **2011 - 2015 Business Plan** | | 970 | 2,606 | 4,735 | 2,491 | | | | **10,802** |
| | **Variance to Budget** | **1,059** | (160) | (93) | (2,335) | (2,491) | **278** | **0** | **11,734** | **7,992** |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Other | **Removal Costs (above)** | | | | | | | | | - |
| | **Inventory W / O** | | | | | | | | | - |
| | **Spare Parts in Invent** | | | | | | | | | - |

| **Reviewed by:** | **(Date)** | **Approved by:** | **(Date)** |
|---|---|---|---|
| Ricardo Fiorini<br>Project Manager | 27-MAY-2011 | George Makdessi<br>Strat IV Manager | 27 May 2011 |

## Liquid Relief Valve Modifications to Reduce Waterhammer 16 - 38933 (OM&A)
## Partial Release Business Case Summary D - BCS - 63310 - 10003 - R000

**ATTACHMENT "B"** **PROJECT VARIANCE ANALYSIS**

| | $ 000's OM&A | LTD Apr 2011 | Total Project | | Variance | Comments |
|---|---|---|---|---|---|---|
| | | | Last BCS Oct 2009 | This BCS May 2011 | | |
| Scores Basis | Project Mgmnt & Support | 375 | 2,506 | 3,056 | 550 | Support costs during installation increased. |
| | Engineering | 851 | 1,377 | 2,655 | 1,278 | Detailed Design scope significantly more complex and detailed than originally estimated. |
| | Procurement | | 4,020 | 6,744 | 2,724 | RFP actual contract costs for design and procurement of LRVs was significantly higher than the budgetary quoted received in 2009.<br>Significant cost increase for valve testing following Tech Spec issuance to vendor with RFP.<br>Cost of NC1 piping and fittings have been added. |
| | Construction | [redacted] | [redacted] | [redacted] | [redacted] | Installation in Refurbishment Outages. Budgetary estimates received from contractors. Installation costs increased slightly. |
| | Other | [redacted] | [redacted] | [redacted] | [redacted] | This includes the contracts with ANRIC Enterprises and Faithful & Gould, 3rd party estimator. |
| | Design Agency | [redacted] | [redacted] | [redacted] | [redacted] | Design Agency required for hydraulic and stress analysis. |
| | | | | | - | |
| | | | | | - | |
| | | | | | - | |
| | Interest (Capital Project Only) | | | | - | |
| | **Project Costs** (Scores Basis) | [redacted] | [redacted] | [redacted] | [redacted] | |
| | General Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Specific Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Project Costs** ( Scores Basis) | **1,276** | **14,443** | **21,609** | **7,166** | |

| | | | | | | |
|---|---|---|---|---|---|---|
| Other | **Removal Costs included above** | | | | - | |
| | **Inventory to be written off** | | | | - | |
| | **Spare Parts in Inventory** | | | | - | |

**Comments:**

## ATTACHMENT "C" SCHEDULE

### Key Milestones

| Completion Date | Description |
|---|---|
| 19-May-11 | PEP Approved |
| 1-Sep-11 | Long Lead Material Contracts Awarded |
| 30-Apr-14 | Detailed Design Complete |
| 31-Dec-15 | Partial Release BCS Approved |
| Click here to enter a date. | |
| Click here to enter a date. | |
| Click here to enter a date. | |
| Click here to enter a date. | |
| Click here to enter a date. | |
| Click here to enter a date. | |
| Click here to enter a date. | |

A Project Execution Plan (PEP) will be approved by 19-May-11

### In Service Declarations: (Capital only)

| Date | Description | $000's (Total = Project Cost incl contg) | % In Service (= 100%) |
|---|---|---|---|
| Click here to enter a date. | | | |
| Click here to enter a date. | | | |
| Click here to enter a date. | | | |
| Click here to enter a date. | | | |
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| Click here to enter a date. | | | |

**Comments:**

## Risk Probabilities Chart

| Likelihood | Improbable | Unlikely | Possible | Likely | Probable |
|---|---|---|---|---|---|
| Probability | <= 1 in 100 | About 1 in 100 | About 1 in 10 | About 1 in 5 | >= 3 in 4 |
| Rank | 1 | 2 | 3 | 4 | 5 |

## Risk Impact Chart

| Impact Rating | Financial | Project Schedule 12 month | Quality | Corporate Reputation | Regulatory / Legal | Health & Safety | Environment | Nuclear Safety |
|---|---|---|---|---|---|---|---|---|
| 5 | >80% of Total Project $ | > 90 day delay | Significant, unacceptable non-conformance requiring extensive rework | National and international adverse coverage or impacts | Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges OR Potential loss of operating licenses | Potential for fatality(s) | Spill or release causing immediate and extended impact with off-site impacts, e.g.:Clean-up costs > $15MCat. A spill (>55 pts) | Loss or serious degradation of a safety system |
| 4 | 30% - 80% of Total Project $ | 30 - 90 day delay | Unacceptable non-conformance requiring some rework, but not major | Long-term local or national impact | Legislative non-compliance with potential for fines, charges, and damages ORMajor degradation of reputation with regulatory bodies | Potential for life-threatening critical injury or permanent total disability, including occupational disease | Exceedances resulting in charges or Director's OrderCat. A spill (45 - 55 pts)Public complaints with OPG implications Explosion and/or major fire | Reduced effectiveness of a safety system |
| 3 | 15% - 30% of Total Project $ | 10 - 30 day delay | Non-conformance bordering design tolerances, potential to require rework | Major local impact or minor national impact.Minor local damage | Systematic non-compliance with potential for finesORPotential to cause strained relationship with regulator, increased surveillance and/or regulations | Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature | Cat. B spills Emission in excedance of regulatory or legal limits Field orders or AMP's Public complaints with OPG implications Danger to health, life, or property | Reduced effectiveness of redundant safety system components |
| 2 | 5% - 15% of Total Project $ | 3 - 10 day delay | Acceptable non-conformance, within design tolerances, no rework required | Complaints from local officials / politicians | Systematic non-compliance with impacts to project scheduleORPossibility of regulatory / legal implications | Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker. | Cat. C spills - reportableAdministrative infractionsPublic Complaints with plant level implications | Impact on a safety support or safety related system |
| 1 | <5% of Total Project $ | < 3 day delay | Minimal impact on qualityRoutine non-conformance, can be easily dispositioned | Complaints from local public | Isolated non-complianceORRoutine approval / notification | No medical attention beyond first aid, no impairment to worker or complete recovery of worker | Administrative, non-reportable eventsCat. C spills non-reportable and spills resulting from Acts of God | |

# Severe Accident Management Guidance Implementation 10 - 62449 (OM&A)
## Developmental Business Case Summary N - BCS - 09013 - 10000 - R000

| Name / Title / Phone | Location | Action | Signature | Date |
|---|---|---|---|---|
| Nick Ivanoff<br>Fukushima Project – Support<br>702-5107 | P82-2 | Prepare BCS | N Ivanoff | March 9, 2012 |
| Elizabeth Lopez<br>Director Fukushima Project<br>702-5070 | P82-2 | Submit BCS | | 9 MAR/12 |
| Randy Leavitt<br>VP Nuclear Finance<br>702-5177 | P82-3 | Approve BCS | RLeavitt | March 29, 2012 |
| Mark Elliott<br>Senior Vice President and CNE<br>702-5418 | P82-5 | Concur with BCS | | April 2/2012 |
| Fred Dermarkar<br>Director, Fukushima Project<br>702-5066 | P82-6 | Approve BCS | ACTING FOR FRED D. | 29 MAR/12 |
| | | | | |
| | | | | |
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| | | | | |
| | | | | |
| Carolyn Sicard<br>Nuclear Investment Management<br>702-4082 | P82-3B6.2 | Return for Distribution | | |

## Severe Accident Management Guidance Implementation 10 - 62449 (OM&A)
## Developmental Business Case Summary N - BCS - 09013 - 10000 - R000

## 1/ RECOMMENDATION:

We recommend a **Developmental** Release of an **initial $0.621** Million **OM&A** to fund **Preliminary Engineering** for this project. Approval of this request will bring the total to date funding to **$0.621** Million including a contingency of [redacted] Million. The total project is estimated to cost **$25.4** Million with an estimated completion date of 12/31/2015

The Business Objective of this **Regulatory** project is to improve the Severe Accident Management Program at OPGN and to ensure that the related CNSC Fukushima Action Items are completed.

While the OPG Nuclear Fleet has already implemented a Severe Accident Management Program, OPG Management has decided to further enhance the capability to respond to a Severe Accident by addressing improvement areas identified during initial implementation, by staging emergency kits to facilitate response, by incorporating the use of new portable Emergency Mitigating Equipment (EME) where possible, and by undertaking assessments to ensure adequacy of response given the lessons learned from the Fukushima Daiichi Nuclear Power Plant accident.

| $000's (incl contingency) | Type | LTD Dec 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Currently Released | None | | | | | | | | | - |
| Adj to Current Release | Adjustments | | | | | | | | | - |
| Requested Now | Develop | | | 621 | | | | | | 621 |
| Future Funding Req'd | Full | | | 5,700 | 12,140 | 3,650 | 3,250 | | | 24,740 |
| **Total Project Costs** | | - | - | **6,321** | **12,140** | **3,650** | **3,250** | - | - | **25,361** |
| Non Project Costs | | | | | | | | | | - |
| Grand Total | | - | - | 6,321 | 12,140 | 3,650 | 3,250 | - | - | 25,361 |

| Investment Type | Class | NPV | IRR | Discounted Payback |
|---|---|---|---|---|
| Regulatory | OM&A | (17,044) | N/A | N/A |

Approved for Developmental Release only; this approval does not endorse the $25.4m total expenditure, although this will be used as a place holder Significant reductions are expected through the challenge process RLeavitt

Submitted By: (Date)

9 MAR/12.

Elizabeth Lopez
Director, Fukushima Support

(OAR Element 1.2 Project not in Budget)

Financial Approval By: (Date)

RLeavitt March 29, 2012

Randy Leavitt
VP Nuclear Finance

Line Approval By: (Date)

FOR FD 29 MAR 2012

Fred Dermarkar
Director, Fukushima Project

## 2/ BACKGROUND & ISSUES:

As a result of the nuclear accident at the Fukushima Daiichi Nuclear Power Plant on March 11 2011, OPGN expedited the implementation of its Severe Accident Management Guidance (SAMG) Program which had been partially established in 2010. The goal of the SAMG program is to establish a means of precluding large uncontrolled releases of radioactivity to the environment subsequent to a severe reactor accident, which is a subset of beyond design basis events.

Phase 1 of the implementation was completed in 2010 and focused initially on providing SAMG within the Emergency Response Organization (ERO). Phase 2 of the implementation plan included issuance of detailed site level proceduralized guidelines; these were completed by July 26, 2011 at both the Darlington and Pickering Nuclear Power Plants. By year end 2011, additional activities associated with Phase 2, including ERO procedure revisions and training of certified staff, were completed.

During Phase 2 implementation, a number of improvement opportunities were identified in SAMG. These included procedural issues, strategy issues, and the need to provide emergency equipment in the field to support the Enabling Instructions. While these issues do not invalidate the use of the guidelines, they must be addressed to ensure timely and effective execution of SAMG should the need arise. Therefore, the need for a further implementation phase (i.e. Phase 3) has been identified. The primary focus of SAMG Phase 3 implementation will be to better prepare for field execution by refining and validating existing guidelines and by training and conducting drills. Additionally, in support of SAMG Improvements, several engineering assessments will be performed as part of Phase 3. These assessments may result in design changes and/or requirements to revise SAMG procedures. In Phase 3, the deliverable for these assessments will include detailed assessment reports and recommendations which will be used to define the scope of all remaining work. Subsequently, a fourth and final phase of SAMG implementation will be required to address the final improvement requirements and complete the project. The scope of Phase 4 will be defined in Q2 2013 when the assessments are completed.

In February 2012, the CNSC issued a number of Fukushima Action Items to OPG. This project includes SAMG Phase 3 <u>and</u> Phase 4; it encompasses all of the work required to improve the SAMG program and complete the actions committed to the CNSC.

**Severe Accident Management Guidance Implementation 10 - 62449 (OM&A)**
**Developmental Business Case Summary N - BCS - 09013 - 10000 - R000**

## 3/ ALTERNATIVES & ECONOMIC ANALYSIS:

| $000's | Base Case | Alt 1 (Recommended) | | Alt 2 |
|---|---|---|---|---|
| | | Full Cost | Incremental Cost | |
| **Total Revenue** | 0 | 0 | 0 | 0 |
| Total OM&A | 0 | (25,381) | (25,381) | N/A |
| **Provision** | 0 | 0 | 0 | 0 |
| **Capital Expenditures** | 0 | 0 | 0 | 0 |
| | | | | |
| **Present Value (PV)** | 0 | (17,044) | (17,044) | N/A |
| **Net Present Value (NPV)** | N/A | (17,044) | (17,044) | N/A |
| | | | | |
| **IRR%** | N/A | N/A | N/A | N/A |
| **Discounted Payback (Yrs)** | N/A | N/A | N/A | N/A |

**Base Case:** × *Not Recommended* - **Do Nothing**

This project is required to address several CNSC Fukushima Action Items and is in response to the CNSC Task Force Report Recommendations for improvements as a result of the lessons learned after the Fukushima Nuclear Power Plant Accident. As such, the Do Nothing option is not a viable alternative.

**Alternative 1:** ✓ *Recommended* - **SAMG Implementation Improvements**

Initial assessments of the required improvements include addressing and correcting items on the gap lists documented during Phase 2 SAMG implementation, staging of Emergency Kits, updating SAMG documents, and performing assessments committed to in the CNSC Fukushima Action Items. Emergency Mitigating Equipment (purchased under Projects 13-49229/49159 and 16-31508) may somewhat offset the scope of SAMG Phase 3 however this needs to be assessed. A Developmental Release is recommended to fully define the scope and cost of the improvements required, a Partial Release and Full Release will follow.

**Alternative 2:** × *Not Recommended* - **SAMG Implementation Improvements (do more)**

SAMG did not originally include the Emergency Mitigation Equipment (EME) which has been recently procured as a result of the Fukushima accident. Completion of SAMG as originally intended included actions which are no longer beneficial when credit is taken for the new EME (i.e. they now become additional or redundant). It is not recommended to implement all gaps associated with earlier implementation of SAMG until an assessment is made which includes crediting the use EME for Severe Accident mitigation.

**Severe Accident Management Guidance Implementation 10 - 62449 (OM&A)**
**Developmental Business Case Summary N - BCS - 09013 - 10000 - R000**

## 4/ THE PROPOSAL

**The deliverables for this Developmental Release are as follows:**

- Complete the preliminary assessments and engineering necessary to define the scope for a partial funding release to implement the proposed improvements to the Severe Accident Management Guidance (SAMG) Program, Phase 3. These assessments include the following improvement areas:
  - reconcile the documented gaps identified during Phase 2 SAMG implementation,
  - stage equipment kits in the field to support deployment during an emergency,
  - conduct training, validation, and drills using the new procedures and equipment
  - update the SAMG Technical Basis Documents
  - revise SAMG documents where appropriate, to include the use of Emergency Mitigating Equipment (e.g. portable pumps and generators) in severe accident situations.
- Complete the preliminary assessments to define the scope of engineering work for a partial funding release required to address improvement areas identified in CNSC Fukushima Action Items. These include assessments of:
  - Equipment and instrument survivability subsequent to Beyond Design Basis Accidents
  - Required strategies for Hydrogen mitigation
  - Required strategies for Containment venting
  - Impact of Shield Tank relief capacity on Containment performance and SAMG strategies
  - Potential impact of SAMG strategies on IFB loss of cooling and inventory makeup accidents
  - Options and SAMG strategies with regard to multi-unit severe accidents
- Prepare and obtain approval of a **Partial Release BCS,** expected July 2012.

**Future Partial Release:**

- Funding for the Partial Release will cover Phase 3 of the SAMG Implementation Improvement Project. Completion of Phase 3 is anticipated to be December 31, 2013.
- Scope of Phase 3 will be as defined in detail and described under the Developmental Release mentioned above.
- The Phase 3 deliverables will include recommendations, based on engineering assessments, that will be used to develop the scope for improvements and/or modifications that may be required in the final Phase of the project.

**Future Full Release**:

- Funding for the Full Release will cover the 4th and final phase of this project.
- Phase 4 SAMG scope will include updates to SAMG documents and implementation of recommendations based on assessments and engineering completed during Phase 3. It will also include updates to SAMG to incorporate equipment procured and plant modification made under the final phase of the Emergency Mitigation Equipment Project.

- Scope of the Full Release will be developed in 2013 and Phase 4 completion is expected by the end of 2015 (plant modification work requiring outages may extend beyond this date)

## 5/ QUALITATIVE FACTORS

The initial qualitative factor gained by proceeding with the project will be to proactively meet OPG commitments to the CNSC to circumvent a regulatory Order. It also demonstrates to the public and our peers, that OPG is applying lessons learned from the Fukushima event in a timely manner. Enhancements to SAMG will address vulnerabilities which currently exist and will improve OPG preparedness to deal with a severe emergency.

## 6/ RISKS ANALYSIS (See Attachment D for details)

| Low<br>1 to 3 | Medium<br>4 to 9 | High<br>10 to 25 |
|---|---|---|

| | | Impact | | | | |
|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 |
| Probability | 5 | 5 | 10 | 15 | 20 | 25 |
| | 4 | 4 | 8 | 12 | 16 | 20 |
| | 3 | 3 | 6 | 9 | 12 | 15 |
| | 2 | 2 | 4 | 6 | 8 | 10 |
| | 1 | 1 | 2 | 3 | 4 | 5 |

| Risk Description | Mitigating Activities | Mitigation | Specific Cont'ncy $000's | Probability X Impact | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Finance | Schedule | Quality | Corporate Reputation | Regulatory | Health & Safety | Environmental | Nuclear Safety | Risk Rating (1 to 25) |
| OPG Engineering and Management resources may be unavailable to do the work or reviews in the required timeframe | Use OPG resources to review engineering estimates and provide oversight of work. Consider external OPG-experienced Project Management, Engineering, and Certified Staff where possible. Consider COG Joint Project with industry partners | Before | | 9 | 9 | | | 2 | | | 2 | 9 |
| | | After | | 3 | 3 | | | 1 | | | 1 | 3 |
| Increased scope due to legacy issues and background information in COG SAMG Documentation Package | Use external previously experienced OPG Engineering and Reactor Safety Staff to assist and provide specific contingency for external engineering support | Before | 30 | 12 | 12 | | | 2 | | | 2 | 12 |
| | | After | | 2 | 2 | | | 1 | | | 1 | 2 |
| Delays to development of scope and scope variations due to need to align with CANDU industry partners | Use membership on COG SAMG Working Group, CANDU Industry Team, and possible COG Joint Project to minimize | Before | | 12 | 12 | | | 2 | | | 2 | 12 |
| | | After | | 4 | 4 | | | 1 | | | 1 | 4 |

## 7/ POST IMPLEMENTATION REVIEW

Note: PIR N/A for Developmental Release

| Type of PIR: | Targeted Final AFS Date: | Targeted PIR Approval Date | PIR Responsibility (Sponsor Title) |
|---|---|---|---|
| Simplified | 31-Dec-15 | 1-Apr-16 | Director Fukushima Project |

| | Measurable Parameter | Current Baseline | Targeted Result | How will it be measured? | Who will measure Person / Group? |
|---|---|---|---|---|---|
| 1. | | | | | |
| 2. | | | | | |
| 3. | | | | | |
| 4. | | | | | |
| 5. | | | | | |

## APPENDIX "A' GLOSSARY (acronyms, codes, technical terms)

CNSC – Canadian Nuclear Safety Commission
OM&A – Operations, Maintenance and Administration
BDBE – Beyond Design Basis Event
EME – Emergency Mitigating Equipment
COG – CANDU Owners Group
ERO – Emergency Response Organization
EP – Emergency Preparedness
SAMG – Severe Accident Management Guidance

## APPENDIX "B" Comparison of Total Project Estimates

| $,000's | | | This Appendix compares the Total Project Estimate for each BCS | | | | | | | | | Total Project |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Actual Project Expenditure (by Year incl Contingency) | | | | | | | | | |
| BCS Type | Class | Mth | Yr | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Later | Est |
| Developmental | OM&A | Mar | 2012 | 6,321 | 12,140 | 3,650 | 3,250 | | | | | 25,361 |
| | | | | | | | | | | | | 0 |
| | | | | | | | | | | | | 0 |
| | | | | | | | | | | | | 0 |
| | | | | | | | | | | | | 0 |
| | | | | | | | | | | | | 0 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LTD Spent | | | | | | | | | | | | 0 |
| LTD Spent | | | | | | | | | | | | 0 |
| LTD Spent | | | | | | | | | | | | 0 |

Comments:

## APPENDIX "C" FINANCIAL MODEL – ASSUMPTIONS

### Financial Assumptions:

| | | | | | |
|---|---|---|---|---|---|
| Discount Rate: | 7% | Cost Escalation (Yr) | 0% | SR&D Opportunity | Yes |
| Progress Payments | No | Foreign Currency | No | Retainer Fee | No |
| Depreciation Rate (Capital) | N/A | PST | No | Interest Rate (Capital) | OM&A N/A |
| Revenue Rate | N/A | Leasing | No | Indexed Priced Contract | No |

**Comments:**

### Project Cost Estimate:

| | | | | | |
|---|---|---|---|---|---|
| Design Complete: | Up to ~ 40% | Fixed Price Contract | No | 3rd Party Estimate | No |
| Quality of Estimate | Budget +30% to -15% | OPEX used | Yes | Lessons Learned | Yes |
| Similar Projects | Nothing Similar | Budgetary Quote | No | First Unit Actual Used | N/A |
| Firm Vendor Proposal | No | Cost Sharing | No | Competitive Bid | No |
| Reviewed by Sponsor | Yes | Fee for Service | No | Contracts in place | No |

**Comments:**

### Rationale for Capital Cost Classification:

### Generation Plan Assumptions:

| Station | Unit | EOL or Refurb | MW | Planned Outages for Project Work | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Pickering A | 1 | Jun-20 | 515 | | | | | | | |
| | 4 | Jun-20 | 515 | | | | | | | |
| Pickering B | 5 | Nov-18 | 516 | | | | | | | |
| | 6 | Nov-18 | 516 | | | | | | | |
| | 7 | Jun-20 | 516 | | | | | | | |
| | 8 | Jun-20 | 516 | | | | | | | |
| Darlington | 1 | Sep-16 | 878 | | | | | | | |
| | 2 | Feb-18 | 878 | | | | | | | |
| | 3 | Sep-19 | 878 | | | | | | | |
| | 4 | Jan-21 | 878 | | | | | | | |

**Comments:**
No outage work anticipated at this time however as scope is developed, may be identified later

## Severe Accident Management Guidance Implementation 10 - 62449 (OM&A)
## Developmental Business Case Summary N - BCS - 09013 - 10000 - R000

**ATTACHMENT "A"** **PROJECT COST SUMMARY**

| | $ 000's OM&A | LTD Dec 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Accounting Basis | Project Mgmnt & Support | | | 841 | 1,300 | 600 | 600 | | | 3,341 |
| | Engineering | | | 3,650 | 6,440 | 2,500 | 2,100 | | | 14,690 |
| | Procurement | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Construction | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Other | | | | | | | | | - |
| | | | | | | | | | | - |
| | | | | | | | | | | - |
| | | | | | | | | | | - |
| | Interest (Capital Project) | | | | | | | | | - |
| | **Project Costs** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | General Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | Specific Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Project Costs** | **-** | **-** | **6,321** | **12,140** | **3,650** | **3,250** | **-** | **-** | **25,361** |

| | $ 000's OM&A | | LTD Dec 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Later | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Funding Basis | **Current Release** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Adj to Current Release** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **This Release** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **TTD Released** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Future Releases** | Project Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | Contingency | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Total** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Project Funding** | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Contingency Funding** | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | **Total Funding** | | **-** | **-** | **6,321** | **12,140** | **3,650** | **3,250** | **-** | **-** | **25,361** |
| Budget | **2011 - 2015 Business Plan** | | | | | | | | | | - |
| | **Variance to Budget** | | 0 | 0 | 5,691 | 10,940 | 3,100 | 2,700 | 0 | 0 | 22,431 |
| Other | **Removal Costs (above)** | | | | | | | | | | - |
| | **Inventory W / O** | | | | | | | | | | - |
| | **Spare Parts in Invent** | | | | | | | | | | - |

**Reviewed by:** N Ivanoff (Date) March 9, 2012

Nick Ivanoff
Project Manager

**Approved by:** E Lopez (Date) 9 MAR 2012

Elizabeth Lopez
Strat V Manager

Filed: 2013-09-27
EB-2013-0321
Ex. F2-3-3
Attachment 1 Tab 10

**Severe Accident Management Guidance Implementation 10 - 62449 (OM&A)**
**Developmental Business Case Summary N - BCS - 09013 - 10000 - R000**

## ATTACHMENT "B" PROJECT VARIANCE ANALYSIS

| | $ 000's | LTD | Total Project | | Variance | Comments |
|---|---|---|---|---|---|---|
| | | N/A<br>N/A | Last BCS<br>N/A<br>N/A | This BCS<br>Mar<br>N/A | | |
| **Scores Basis** | Project Mgmnt & Support | | | 3,341 | 3,341 | N/A, first release |
| | Engineering | | | 14,690 | 14,690 | N/A, first release |
| | Procurement | | | 1,700 | 1,700 | N/A, first release |
| | Construction | [redacted] | [redacted] | [redacted] | [redacted] | N/A, first release |
| | Other | [redacted] | [redacted] | [redacted] | [redacted] | |
| | | | | | - | |
| | | | | | - | |
| | | | | | - | |
| | | | | | - | |
| | Interest (Capital Project Only) | [redacted] | [redacted] | [redacted] | [redacted] | |
| | **Project Costs (Scores Basis)** | [redacted] | [redacted] | [redacted] | [redacted] | **N/A, first release** |
| | General Contingency | [redacted] | [redacted] | [redacted] | [redacted] | **N/A, first release** |
| | Specific Contingency | [redacted] | [redacted] | [redacted] | [redacted] | N/A, first release |
| | **Project Costs ( Scores Basis)** | - | - | **25,361** | **25,361** | N/A, first release |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Other** | **Removal Costs included above** | | | | - | |
| | **Inventory to be written off** | | | | - | |
| | **Spare Parts in Inventory** | | | | - | |

**Comments:**

This is the first release; therefore, no variance analysis is required.

## ATTACHMENT "C" SCHEDULE

### Key Milestones

| Completion Date | Description |
|---|---|
| 31-Jul-12 | Partial BCS - Funds approved for release |
| 30-Jun-13 | Scope developed for Phase 4 of SAMG |
| 31-Dec-13 | SAMG Phase 3 complete and Full Release approved for Phase 4 SAMG |
| 31-Dec-15 | SAMG fully implemented (Phase 3 and 4), Project complete |
| Click here to enter a date. | |
| Click here to enter a date. | |
| Click here to enter a date. | |
| Click here to enter a date. | |
| Click here to enter a date. | |
| Click here to enter a date. | |
| Click here to enter a date. | |

A Project Execution Plan (PEP) will be approved by 31-Aug-12

### In Service Declarations: (Capital only)

| Date | Description | $000's | % In Service (= 100%) |
|---|---|---|---|
| Click here to enter a date. | | | |
| Click here to enter a date. | | | |
| Click here to enter a date. | | | |
| Click here to enter a date. | | | |
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**Comments:**

Filed: 2013-09-27
EB-2013-0321
Ex. F2-3-3
Attachment 1 Tab 10

## Severe Accident Management Guidance Implementation 10 - 62449 (OM&A)
## Developmental Business Case Summary N - BCS - 09013 - 10000 - R000

**Attachment "D"**

### Risk Probabilities Chart

| Likelihood | Improbable | Unlikely | Possible | Likely | Probable |
|---|---|---|---|---|---|
| Probability | <= 1 in 100 | About 1 in 100 | About 1 in 10 | About 1 in 5 | >= 3 in 4 |
| Rank | 1 | 2 | 3 | 4 | 5 |

### Risk Impact Chart

| Impact Rating | Financial | Project Schedule 12 month | Quality | Corporate Reputation | Regulatory / Legal | Health & Safety | Environment | Nuclear Safety |
|---|---|---|---|---|---|---|---|---|
| 5 | >80% of Total Project $ | > 90 day delay | Significant, unacceptable non-conformance requiring extensive rework | National and international adverse coverage or impacts | Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges OR Potential loss of operating licenses | Potential for fatality(s) | Spill or release causing immediate and extended impact with off-site impacts, e.g.:Clean-up costs > $15MCat. A spill (>55 pts) | Loss or serious degradation of a safety system |
| 4 | 30% - 80% of Total Project $ | 30 - 90 day delay | Unacceptable non-conformance requiring some rework, but not major | Long-term local or national impact | Legislative non-compliance with potential for fines, charges, and damages ORMajor degradation of reputation with regulatory bodies | Potential for life-threatening critical injury or permanent total disability, including occupational disease | Exceedances resulting in charges or Director's OrderCat. A spill (45 - 55 pts)Public complaints with OPG implications Explosion and/or major fire | Reduced effectiveness of a safety system |
| 3 | 15% - 30% of Total Project $ | 10 - 30 day delay | Non-conformance bordering design tolerances, potential to require rework | Major local impact or minor national impact.Minor local damage | Systematic non-compliance with potential for finesORPotential to cause strained relationship with regulator, increased surveillance and/or regulations | Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature | Cat. B spillsEmission in exceedance of regulatory or legal limitsField orders or AMP'sPublic complaints with OPG implicationsDanger to health, life, or property | Reduced effectiveness of redundant safety system components |
| 2 | 5% - 15% of Total Project $ | 3 - 10 day delay | Acceptable non-conformance, within design tolerances, no rework required | Complaints from local officials / politicians | Systematic non-compliance with impacts to project scheduleORPossibility of regulatory / legal implications | Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker | Cat. C spills - reportableAdministrative infractionsPublic Complaints with plant level implications | Impact on a safety support or safety related system |
| 1 | <5% of Total Project $ | < 3 day delay | Minimal impact on qualityRoutine non-conformance, can be easily dispositioned | Complaints from local public | Isolated non-complianceORRoutine approval / notification | No medical attention beyond first aid, no impairment to worker or complete recovery of worker | Administrative, non-reportable eventsCat. C spills non-reportable and spills resulting from Acts of God | |

Numbers may not add due to rounding.

Table 1
Comparison of Other Revenues - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

| Line No. | Revenue Source | 2010 Budget | (c)-(a) Change | 2010 Actual | (g)-(c) Change | 2011 Board Approved | (g)-(e) Change | 2011 Actual | (i)-(g) Change | 2012 Actual |
|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | | | | | | | | | | |
| | **Niagara Plant Group and Saunders GS:** | | | | | | | | | |
| 1 | **Ancillary Services**[1] | 39.1 | (12.9) | 26.2 | (4.0) | [redacted] | (16.1) | 22.2 | (1.4) | 20.8 |
| 2 | **Segregated Mode of Operation**[2] | 6.6 | (7.5) | (0.9) | 2.6 | 1.5 | 0.2 | 1.7 | (2.5) | (0.8) |
| 3 | **Water Transactions**[3] | 6.9 | (1.4) | 5.5 | 2.0 | 6.0 | 1.5 | 7.5 | (5.9) | 1.6 |
| 4 | **HIM Revenue Requirement Adjustment** [4] | | | | | 5.0 | | | | |
| 5 | **Subtotal** | 52.6 | (21.8) | 30.8 | 0.7 | [redacted] | (19.4) | 31.5 | (9.8) | 21.6 |
| | | | | | | | | | | |
| | **Newly Regulated Hydroelectric:** | | | | | | | | | |
| | **Ottawa-St. Lawrence[5], Central, Northeast and Northwest Plant Groups:** | | | | | | | | | |
| 6 | **Ancillary Services** | 29.5 | (3.1) | 26.4 | (0.2) | 24.4 | 1.7 | 26.1 | (0.3) | 25.9 |
| 7 | **Segregated Mode of Operation** | 0.0 | 0.0 | 0.0 | (0.0) | 0.0 | 0.0 | 0.0 | (0.0) | 0.0 |
| 8 | **Subtotal** | 29.5 | (3.1) | 26.4 | (0.2) | 24.4 | 1.8 | 26.1 | (0.3) | 25.9 |
| | | | | | | | | | | |
| 9 | **Total** | 82.0 | (24.9) | 57.2 | 0.4 | [redacted] | (17.6) | 57.6 | (10.1) | 47.5 |

| Line No. | Revenue Source | 2012 Board Approved | (c)-(a) Change | 2012 Actual | (e)-(c) Change | 2013 Budget | (g)-(e) Change | 2014 Plan | (i)-(g) Change | 2015 Plan |
|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | | | | | | | | | | |
| | **Niagara Plant Group and Saunders GS:** | | | | | | | | | |
| 10 | **Ancillary Services**[1] | [redacted] | (18.6) | 20.8 | (3.1) | 17.8 | 0.4 | 18.1 | 0.4 | 18.5 |
| 11 | **Segregated Mode of Operation**[2] | 1.6 | (2.4) | (0.8) | 2.4 | 1.6 | (1.5) | 0.0 | 0.0 | 0.0 |
| 12 | **Water Transactions**[3] | 6.0 | (4.4) | 1.6 | 4.4 | 6.0 | (4.3) | 1.7 | 0.0 | 1.7 |
| 13 | **HIM Revenue Requirement Adjustment** [4] | 7.0 | | | | 6.5 | N/A | N/A | N/A | N/A |
| 14 | **Subtotal** | [redacted] | (32.4) | 21.6 | 10.2 | 31.8 | (12.0) | 19.9 | 0.4 | 20.2 |
| | | | | | | | | | | |
| | **Newly Regulated Hydroelectric:** | | | | | | | | | |
| | **Ottawa-St. Lawrence[5], Central, Northeast and Northwest Plant Groups:** | | | | | | | | | |
| 15 | **Ancillary Services** | 25.1 | 0.7 | 25.9 | (3.7) | 22.2 | 0.4 | 22.7 | 0.5 | 23.1 |
| 16 | **Segregated Mode of Operation** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 17 | **Subtotal** | 25.1 | 0.7 | 25.9 | (3.7) | 22.2 | 0.4 | 22.7 | 0.5 | 23.1 |
| | | | | | | | | | | |
| 18 | **Total** | [redacted] | (31.7) | 47.5 | 6.6 | 54.1 | (11.5) | 42.5 | 0.8 | 43.3 |

Notes:

1 Ancillary Services related to Hydroelectric prescribed facilities are discussed in Ex. G1-1-1.

2 Segregated Mode of Operation (SMO) net revenues are gross revenues less HOEP, less export fees, transmission charges in other control areas, transmission losses, production losses during the switching process between control areas and costs associated with the non-regulated Trading business.

3 Water Transactions (WT) revenues are gross revenues net of accommodation charges and Gross Revenue Charges (GRC).
Water Transactions figures for 2011 Board Approved and 2012 Board Approved reflect EB-2010-0008 Decision and Order, p. 33.

4 Per the EB-2010-0008 Decision (p. 147) for 2011 and 2012 and EB-2012-0002 Payments Amount Order for 2013, 50% of Hydroelectric Incentive Mechanism (HIM) revenues are returned to ratepayers as an offset to the revenue requirement, with offset amounts of $5M and $7M identified for 2011 and 2012 Board Approved, respectively, and $6.5M for 2013. For the test period, OPG is proposing no offset be applied to the revenue requirement. For HIM Plan refer to Ex. E1-2-1 section 5.2.

5 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

Numbers may not add due to rounding.

### Table 1
### Comparison of Other Revenues - Nuclear ($M)

| ` No. | Revenue Source | 2010 Budget | (c)-(a) Change | 2010 Actual | (g)-(c) Change | 2011 Board Approved | (g)-(e) Change | 2011 Actual | (i)-(g) Change | 2012 Actual |
|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | | | | | | | | | | |
| | **NGD-Related Revenues:** | | | | | | | | | |
| 1 | **Heavy Water Sales & Processing[1]** | 23.1 | 3.6 | 26.7 | 54.2 | [redacted] | 58.0 | 80.9 | (25.8) | 55.1 |
| 2 | **Isotope Sales (Cobalt 60 + Tritium)** | 9.3 | 0.8 | 10.1 | (5.2) | 9.6 | (4.7) | 4.8 | 6.6 | 11.5 |
| 3 | **Inspection & Maintenance Services** | 44.5 | (8.5) | 36.0 | (28.9) | 19.7 | (12.6) | 7.1 | (3.0) | 4.1 |
| 4 | **Helium-3 Sales** | 0.0 | | 0.0 | | 0.0 | | 0.0 | | 0.0 |
| 5 | **Total NGD-Related Revenues** | 77.0 | (4.2) | 72.8 | 20.1 | [redacted] | 40.7 | 92.9 | (22.2) | 70.6 |
| | | | | | | | | | | |
| 6 | **NGD-Related Direct Costs** | 31.9 | (0.4) | 31.5 | (20.8) | 18.3 | (7.6) | 10.7 | (2.0) | 8.7 |
| 7 | **NGD-Related Contribution Margin** | 45.0 | (3.8) | 41.3 | 40.9 | [redacted] | 48.3 | 82.2 | (20.3) | 61.9 |
| | | | | | | | | | | |
| 8 | **Ancillary Services[2]** | 2.9 | (0.3) | 2.6 | (0.2) | 2.9 | (0.5) | 2.4 | (0.6) | 1.8 |
| 9 | **Other[3]** | 0.1 | 0.7 | 0.8 | (0.3) | 0.1 | 0.5 | 0.6 | (0.5) | 0.1 |

| Line No. | Revenue Source | 2012 Board Approved | (c)-(a) Change | 2012 Actual | (e)-(c) Change | 2013 Budget | (g)-(e) Change | 2014 Plan | (i)-(g) Change | 2015 Plan |
|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | | | | | | | | | | |
| | **NGD-Related Revenues:** | | | | | | | | | |
| 10 | **Heavy Water Sales & Processing[1]** | [redacted] | 33.2 | 55.1 | (36.2) | 18.9 | 7.4 | 26.3 | (6.0) | 20.4 |
| 11 | **Isotope Sales (Cobalt 60 + Tritium)** | 11.0 | 0.5 | 11.5 | (0.4) | 11.1 | 0.5 | 11.6 | 0.3 | 11.9 |
| 12 | **Inspection & Maintenance Services** | 0.0 | 4.1 | 4.1 | (4.1) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 13 | **Helium-3 Sales** | 0.0 | | | | 0.0 | | 0.0 | | 4.0 |
| 14 | **Total NGD-Related Revenues** | [redacted] | 37.8 | 70.6 | (40.6) | 30.0 | 8.0 | 38.0 | (5.7) | 36.3 |
| | | | | | | | | | | |
| 15 | **NGD-Related Direct Costs** | 6.6 | 2.1 | 8.7 | (1.5) | 7.2 | (0.4) | 6.8 | 1.0 | 7.8 |
| 16 | **NGD-Related Contribution Margin** | [redacted] | 35.6 | 61.9 | (39.1) | 22.8 | 8.4 | 31.2 | (6.7) | 28.5 |
| | | | | | | | | | | |
| 17 | **Ancillary Services[2]** | 3.0 | (1.1) | 1.8 | 0.0 | 1.9 | 0.0 | 1.9 | 0.0 | 1.9 |
| 18 | **Other[3]** | 0.1 | 0.0 | 0.1 | 0.0 | 0.1 | 0.0 | 0.1 | 0.0 | 0.1 |

Notes:

1 Starting in 2011, Other Revenues included in the determination of the revenue requirement are adjusted for sharing of 50 percent of net revenue from sales of heavy water per the OEB Decision in EB-2010-0008. The 50% share of net revenues, which have been netted out of the amounts in lines 1 and 10, are as follows:

Table to Note 1 - 50% Share of Net Revenues from Heavy Water Sales ($M)

| Line No. | | 2011 Board Approved[#] | 2012 Board Approved[#] | 2013 Budget | 2014 Plan | 2015 Plan |
|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| 1a | 50% Share of Net Revenues from Heavy Water Sales | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

\# Based on EB-2010-0008 Payment Amounts Order, App. A, Table 2.

2 Ancillary Services related to the Nuclear prescribed facilities are discussed in Ex. G1-1-1.

3 Other includes net revenues of $0.1M-$0.8M per year over the period 2010-2015 earned from the provision of various consulting services to third parties (e.g. fire and protection training).

Numbers may not add due to rounding.

### Table 2
### Comparison of Revenue Requirement to Board Approved - Previously Regulated Hydroelectric ($M)
### Years Ending December 31, 2011, 2012, 2013, 2014 and 2015

| Line | | | Board Approved[1] | | Actual | | Forecast | | |
|---|---|---|---|---|---|---|---|---|---|
| No. | Description | Note | 2011 | 2012 | 2011 | 2012 | 2013 | 2014 | 2015 |
| | | | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| 1 | **Total Cost of Capital** | 2 | 278.2 | 280.4 | 181.6 | 186.9 | 398.3 | 347.1 | 345.4 |
| | **Expenses:** | | | | | | | | |
| 2 | **OM&A** | 3 | 128.2 | 125.9 | 96.3 | 119.7 | 141.3 | 145.5 | 141.1 |
| 3 | **GRC** | 4 | 263.7 | 263.7 | 259.4 | 244.5 | 243.5 | 253.3 | 269.5 |
| 4 | **Depreciation & Amortization** | 5 | 65.6 | 65.0 | 65.6 | 70.0 | 79.0 | 82.1 | 81.9 |
| 5 | **Property Tax** | 6 | 0.0 | 0.0 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 |
| 6 | **Total Expenses** | | 457.5 | 454.6 | 421.4 | 434.3 | 464.2 | 481.1 | 492.9 |
| | **Less:** | | | | | | | | |
| | **Other Revenues** | | | | | | | | |
| 7 | **Ancillary and Other Revenue** | 7 | [redacted] | [redacted] | 31.5 | 21.6 | 31.8 | 19.9 | 20.2 |
| 8 | **Total Other Revenues** | | [redacted] | [redacted] | 31.5 | 21.6 | 31.8 | 19.9 | 20.2 |
| 9 | **Income Tax** | 6 | [redacted] | [redacted] | 33.4 | 32.3 | (0.7) | 48.5 | 61.5 |
| 10 | **Revenue Requirement** | 5 | 711.9 | 707.2 | 605.0 | 631.9 | 829.9 | 856.7 | 879.5 |
| | (line 1 + line 6 - line 8 + line 9) | | | | | | | | |
| 11 | **Forecast Production (TWh)** | 8 | 19.8 | 19.8 | 19.5 | 18.5 | 18.4 | 19.1 | 20.2 |

Notes:

1 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 1, except forecast production which is from Appendix A, Table 3.

2 Actuals and Forecast: Totals from Ex. C1-1-1 Tables 1 through 4 (col. (d)) and Ex. C1-1-1 Table 5 (col. (f)).
Cost of Capital is allocated to Previously Regulated Hydroelectric operations using rate base financed by capital structure,
except for 2013 where Return on Equity portion is from I1-1-1 Table 5, line 25.

3 Actuals and Forecast from Ex. F1-1-1 Table 1.

4 Actuals and Forecast from Ex. F1-4-1 Table 1.

5 Actuals and Forecast from Ex. F4-1-1 Table 1.

6 Actuals and Forecast from Ex. F4-2-1 Table 1.

7 Actuals and Forecast from Ex. G1-1-1 Table 1.

8 Actuals and Forecast from Ex. E1-1-1 Table 1.

Numbers may not add due to rounding.

### Table 3
### Comparison of Revenue Requirement to Board Approved - Nuclear ($M)
### Years Ending December 31, 2011, 2012, 2013, 2014 and 2015

| Line | | | Board Approved[1] | | Actual | | Forecast | | |
|---|---|---|---|---|---|---|---|---|---|
| **No.** | **Description** | **Note** | **2011** | **2012** | **2011** | **2012** | **2013** | **2014** | **2015** |
| | | | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| | | | | | | | | | |
| 1 | **Total Cost of Capital** | 2 | 260.0 | 257.4 | 197.2 | 214.4 | (32.2) | 231.4 | 229.9 |
| | | | | | | | | | |
| | **Expenses:** | | | | | | | | |
| 2 | **OM&A** | 3 | 1,965.5 | 1,976.3 | 2,116.3 | 2,230.0 | 2,493.0 | 2,422.7 | 2,473.3 |
| 3 | **Fuel** | 4 | 240.1 | 266.2 | 228.9 | 265.1 | 272.6 | 280.5 | 267.9 |
| 4 | **Depreciation & Amortization** | 5 | 235.4 | 256.4 | 228.6 | 341.9 | 256.5 | 273.7 | 288.5 |
| 5 | **Property Tax** | 6 | 16.0 | 16.6 | 13.6 | 13.3 | 15.3 | 15.9 | 16.4 |
| 6 | **Total Expenses** | | 2,457.1 | 2,515.6 | 2,587.4 | 2,850.3 | 3,037.4 | 2,992.8 | 3,046.3 |
| | | | | | | | | | |
| | **Less:** | | | | | | | | |
| | **Other Revenues** | | | | | | | | |
| 7 | **Bruce Lease Revenues Net of Direct Costs** | 7 | 128.1 | 143.0 | 84.2 | 93.2 | 42.3 | 39.7 | 40.6 |
| 8 | **Ancillary and Other Revenue** | 8 | [redacted] | [redacted] | 85.1 | 63.8 | 24.8 | 33.2 | 30.5 |
| 9 | **Total Other Revenues** | | [redacted] | [redacted] | 169.3 | 157.0 | 67.1 | 72.9 | 71.1 |
| | | | | | | | | | |
| 10 | **Income Tax** | 6 | [redacted] | [redacted] | (25.3) | 9.4 | (23.9) | 140.8 | 47.5 |
| | | | | | | | | | |
| 11 | **Revenue Requirement** | 5 | 2,586.0 | 2,665.5 | 2,590.0 | 2,917.1 | 2,914.2 | 3,292.2 | 3,252.6 |
| | (line 1 + line 6 - line 9 + line 10) | | | | | | | | |
| | | | | | | | | | |
| 12 | **Forecast Production (TWh)** | 9 | 50.4 | 51.5 | 48.6 | 49.0 | 48.0 | 49.7 | 48.0 |

Notes:

1 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 2, except forecast production which is from Appendix A, Table 3.

2 Actuals and Forecast: Totals from Ex. C1-1-1 Tables 1 through 4 (col. (d)) and Ex. C1-1-1 Table 5 (col. (f)).
Cost of Capital is allocated to Nuclear operations using rate base financed by capital structure, except for 2013 where Return on Equity portion is from I1-1-1 Table 5, line 25.

3 Actuals and Forecast from Ex. F2-1-1 Table 1.

4 Actuals and Forecast from Ex. F2-5-1 Table 1.

5 Actuals and Forecast from Ex. F4-1-1 Table 2.

6 Actuals and Forecast from Ex. F4-2-1 Table 3.

7 Actuals and Forecast from Ex. G2-2-1 Table 1.

8 Actuals and Forecast from Ex. G2-1-1 Table 1.
Other Revenues included in the determination of the Nuclear revenue requirement are adjusted for sharing of 50 percent of net revenue from sales of heavy water per the OEB Decision in EB-2010-0008, per Ex. G2-1-2 Table 1, Note 1.

9 Actuals and Forecast from Ex. E2-1-1 Table 1.

# ATTACHMENT B – CONFIDENTIAL

*[for the OEB's consideration only]*

**EB-2013-0321**

# ATTACHMENT C – NON-CONFIDENTIAL

*Letters Regarding Confidential Treatment of Unregulated Facility Information in EB-2010-0008*

ONTARIO POWER GENERATION

**Barbara Reuber**
Director

Ontario Regulatory Affairs

700 University Avenue, Toronto, Ontario M5G 1X6
**Tel: 416-592-5419** Fax: 416-592-8519
barbara.reuber@opg.com

July 2, 2010

VIA EMAIL AND RESS

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON
M4P 1E4

Dear Ms. Walli:

**Re: EB-2010-0008 – Ontario Power Generation Inc. 2011-2012 Payment Amounts for Prescribed Facilities**

In accordance with Procedural Order No. 1**,** Rule 10 of the Ontario Energy Board's (OEB) *Rules of Practice and Procedure* and section 5.1 of the OEB's *Practice Direction on Confidential Filings* (the "*Practice Direction*"), Ontario Power Generation Inc. ("OPG") requests confidential treatment for certain portions of its 2010 – 2014 business plans for the Nuclear and Hydroelectric businesses (collectively, the "Business Plans") and for certain portions of its Business Case Summaries (the "BCSs") included as part of the pre-filed evidence.

OPG has set out below the reasons for the confidentiality request, and the reasons why public disclosure would be detrimental to OPG.

Also, as set out further below, OPG is retaining certain redactions in the Hydroelectric Business Plan and the redacton of two numbers in the Nuclear Operations Business Plan.

In accordance with Procedural Order No. 1, this letter is being provided to the OEB along with a CD of the unredacted Business Plans and the BCSs, as attachments "A" and "B", respectively. Attachment A is labeled "Business Plans – Unredacted Confidential" and Attachment B is labeled "Business Case Summaries – Unredacted Confidential". Six hard copies of the unredacted materials will be provided by Tuesday, July 6, 2010. OPG has not provided the unredacted copy of the BCS for Nuclear project number 49104 Auxilliary Power System and will forward it as soon as possible.

Should the OEB grant OPG's request for confidentiality, OPG proposes that the OEB order that the confidential parts of the Business Plans and BCSs be disclosed, subject to any conditions the OEB may find appropriate, to only those persons that have signed the Declaration and Undertaking referenced in Procedural Order No. 1.

In addition, OPG requests that any reference to the parts of the Business Plans and the BCSs determined to be confidential information be conducted *in camera* so as to preserve their confidential nature.

## Reasons for Retaining Certain Redactions

The redacted portions of the Hydroelectric 2010 – 2014 Business Plan at Exhibit F1-1-1, Attachment 1, include information that relates to OPG's unregulated hydroelectric business. The redacted information related to the unregulated business is not relevant to the determination of OPG's payment amounts. OPG has consistently treated this information as confidential because it is commercially sensistive.

The redactions related to the unregulated business in the Hydroelectric Business Plan fall into two categories. First, certain of these redactions relate to information reflecting the combined regulated and unregulated assets. The disclosure of this aggregated information (combined with information regarding the regulated business already disclosed) would allow for the disclosure of information related to the unregulated facilities. This information is disclosed in the unredacted confidential version filed in Attachment A and for the reasons set out below, OPG requests confidential treatment for this information.

The second category includes redactions that relate solely to the unregulated facilities and reflect no aspect of the regulated business. For example, this information includes timelines, in-service dates and costs for unregulated hydroelectric development projects. Because this redacted information is wholly irrelevant to OPG's payment amounts proceeding, OPG has continued to redact this information in the confidential version filed in Attachment A.

The redacted portion of the Nuclear Operations 2010 – 2014 Business Plan at Exhibit F2-1-1, Attachment 1, is limited to just two numerical figures that relate to the best quartile and median results for the All Injury Rate (AIR) performance metric. This information is provided to OPG by the Canadian Electrical Association (CEA) on the basis that it not be disclosed.

Disclosure of this CEA data may result in OPG being blocked from further participation in CEA benchmarking or the termination of further CEA benchmarking on that metric. It is higly important to OPG's business that it continue to participate in CEA benchmarking. Disclosure of this redacted information, even under the OEB's confidentiality guidelines, could therefore be highly prejudicial to OPG.

While the first quartile and median benchmarking values of the AIR metric are not disclosed, in its pre-filed evidence at Exhibit F5-1-1 page 18, OPG shows that the performance of all OPG nuclear plants has been above best quartile in respect of the AIR metric since 2003.

## Reasons for Confidential Treatment of the Business Plans

The redacted portions of the Hydroelectric 2010 – 2014 Business Plan at Exhibit F1-1-1, Attachment 1, should be protected as confidential and not placed on the public record because they would allow disclosure of information that relates to the unregulated hydroelectric business. OPG consistently treats this information on the unregulated hydroelectric business as confidential financial information because it is commercially sensitive. For the hydroelectric development projects, public release of information on costs and schedules for the work may influence suppliers' bids and ultimately increase the cost for the work. For the unregulated facilities that are offering into the IESO-administered markets, public release of information regarding costs may influence other market participants' bids and offers to the competitive disadvantage of OPG.

The redacted portions of the Nuclear Refurbishment, Projects and Support 2010 – 2014 Business Plan at Exhibit D2-2-1, Attachment 1, should be protected as confidential and not placed on the public record because they include information that is commercially sensitive, including contingencies and costs for contracted or purchased work or materials. This information should not be on the public record because if OPG's budgets for work, even on a preliminary basis, are available they may affect suppliers' bids for the work and ultimately increase the cost for the work.

Disclosure of the redacted portions of Hydroelectric and Nuclear Refurbishment business plans to the public and to any persons who do not acknowledge the information to be confidential and undertake to keep it confidential and to use it exclusively for their duties in respect of OPG's payment amounts application, would prejudice OPG's competitive position and significantly interfere with its negotiations in a variety of aspects of its business.

## Reasons for Confidential Treatment of the Business Case Summaries

The Regulated Hydroelectric business case summaries at Exhibit D1-1-2 and the Nuclear business case summaries at Exhibit D2-1-2 and Exhibit F2-3-3, with redactions, have been assembled and filed as Volume 4 of OPG's pre-filed evidence. An additional BCS relating to Darlington refurbishment is filed as Exhibit D2-2-1, Attachment 1.

The redacted portions of the BCSs should be protected as confidential and not placed on the public record because they include commercially sensitive information including contingencies, costs for contracted or purchased work or materials, margins for commercial products or services, or aggregate information that would allow determination of commercially sensitive information.

Disclosure of the redacted portions of BCSs that include OPG commercially sensitive information would prejudice OPG's competitive position and significantly interfere with its negotiations and existing relationships in a variety of aspects of its business.

Respectfully submitted,

[Original signed by]

Barbara Reuber
Director, Ontario Regulatory Affairs

Attach

cc: Charles Keizer (Tory's)
Carlton D. Mathias

**Ontario Energy**
**Board**
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

**Commission de l'énergie**
**de l'Ontario**
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone: 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

Ontario

**BY EMAIL**

August 5, 2010

Carlton D. Mathias
Senior Counsel, Law Division
Ontario Power Generation Inc.
700 University Avenue, H18A24
Toronto ON M5G 1X6

Dear Mr. Mathias:

**Re: Ontario Power Generation Inc.**
**2011-2012 Payment Amounts for Prescribed Generation Facilities**
**Board File Number EB-2010-0008**

This will acknowledge that the Board received a fully unredacted version of the Hydroelectric 2010-2014 Business Plan on July 26, 2010 pursuant to Procedural Order No. 3. The Board has compared the Business Plan filed on July 26, 2010 with that filed on July 2, 2010. Both documents were filed in confidence.

The Board has reviewed the Business Plans and is satisfied that the redactions in the July 2, 2010 version of the Business Plan relate solely to OPG's unregulated hydroelectric facilities.

The Board is returning the fully unredacted Business Plan to OPG with this correspondence.

Yours truly,

*Original signed by*

Kirsten Walli
Board Secretary

CC: Barbara Reuber, OPG
Charles Keizer, Torys
All parties to EB-2010-0008

**EB-2013-0321**

# ATTACHMENT D – NON-CONFIDENTIAL

*Procedural Order No. 3 in EB-2010-0008*

**Ontario Energy Board** **Commission de l'énergie de l'Ontario**

Ontario

**EB-2010-0008**

**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.

# DECISIONS AND ORDERS ON CONFIDENTIAL FILINGS AND ISSUES LIST, AND PROCEDURAL ORDER NO. 3

Ontario Power Generation Inc. ("OPG" or the "Applicant") filed an application, dated May 26, 2010, with the Ontario Energy Board under section 78.1 of the *Ontario Energy Board Act,1998,* S.O. 1998, c.15, Schedule B (the "Act") seeking approval for increases in payment amounts for the output of certain of its generating facilities, to be effective March 1, 2011.

On June 29, 2010, the Board issued Procedural Order No. 1 which set out a schedule for the proceeding, and which contained a draft issues list. On July 5, 2010, the Board issued Procedural Order No. 2 which amended the dates for parties to provide submissions on sections of the application for which OPG has requested confidential treatment. In accordance with Procedural Order No. 1, an Issues Conference was held on July 6, 2010, and on July 7, 2010 the Board issued a revised draft issues list which had been prepared by Board staff based on input received at the Issues Conference.

## Confidential Filing

OPG has sought confidential treatment for certain Tax Information filed with the application in accordance with the Board's *Practice Direction on Confidential Filings* (the "Practice Direction"). OPG also filed Business Case Summaries ("BCS") and 2010-2014 Hydroelectric and Nuclear Business Plan information ("Business Plan") in redacted form with its application. This redacted material was not filed in accordance with the Practice Direction. Procedural Order No. 1 directed OPG to file the BCS and Business Plan in unredacted form, and to provide a description of the basis on which confidentiality is claimed. OPG filed unredacted documents and a letter providing reasons for confidential treatment of the Business Plan and BCS on July 2, 2010. OPG noted in its letter that it has continued to redact information related to unregulated hydroelectric facilities and certain benchmarking information.

Procedural Order No. 1 made provision for parties that submit a Declaration and Undertaking, to review the Tax Information, Business Plan and BCS. Procedural Order No. 1 also made provision for parties to make submissions on the confidentiality status of the Tax Information, Business Plan and BCS. Provision was also made for OPG to respond to any submission. Procedural Order No. 2 amended the dates for submissions of parties to July 12, 2010 and for OPG's reply submission to July 16, 2010.

On July 9, 2010, OPG informed parties that in the process of complying with Procedural No. 1, it had discovered that for several of the BCS for nuclear facilities, confidential treatment was no longer required due to the passage of time. On July 15, 2010, OPG filed these unredacted BCS. With this filing, the number of unredacted BCS has increased from 5, in the original application, to 22. The number of redacted BCS is currently 34.

Submissions on confidential filings were received from the Association of Major Power Consumers in Ontario ("AMPCO"), the Canadian Manufacturers & Exporters ("CME"), the Consumers Council of Canada ("CCC"), Pollution Probe and the School Energy Coalition ("SEC").

There were no objections to OPG's request for confidential treatment of the Tax Information. There were no objections to OPG's request for confidential treatment for BCS, with the exception of two projects: the Niagara Tunnel and the Darlington Refurbishment.

### Niagara Tunnel

AMPCO submitted that it does not believe that the BCS for the Niagara Tunnel meets the criteria suggested by OPG for maintaining confidentiality. SEC stated that the Niagara Tunnel project involves more than a 60% cost overrun and is a matter of considerable public interest. SEC submitted that it is the Board's role to expose matters such as this to public scrutiny. SEC stated that nothing in the BCS appears to have potential to prejudice OPG.

In reply, OPG addressed the three aspects of the information in the Niagara Tunnel Project BCS for which it seeks confidential treatment.

1. OPG's contingency information is not known to the contractor, Strabag AG. Knowledge of the contingency information could prejudice OPG's competitive position and limit OPG's capacity to enforce contractual terms.
2. The target cost and schedule information is known to Strabag, however, in the event that OPG was required to negotiate arrangements with another party, prior knowledge of target cost and schedule would prejudice OPG's negotiating position.
3. Information related to community agreement is redacted. Public disclosure would compromise OPG's negotiating position.

### Darlington Refurbishment

AMPCO submitted that the "Economic Feasibility Assessment of Darlington Refurbishment" and the redactions relating to the Darlington Refurbishment Project in the Nuclear Refurbishment Projects and Support Business Plan do not meet the test for confidentiality. Pollution Probe also provided a submission on the "Economic Feasibility Assessment of Darlington Refurbishment". Pollution Probe noted specific page references and stated that these redactions do not meet the exceptions detailed in the Board's Practice Direction. Pollution Probe stated that the information is a high level summary and would not be prejudicial to OPG if made public. As construction work in progress for Darlington will be reviewed in this proceeding, Pollution Probe states that high level numbers regarding the economic analysis, including levelized unit energy cost ("LUEC") ought to be public.

In reply, OPG addressed the two aspects of the information in the Darlington Refurbishment BCS for which it seeks confidential treatment.

1. OPG stated that point estimates of project costs, LUEC and contingencies could be used by potential suppliers to approximate project component costs. These

approximations could place OPG at a disadvantage relative to project suppliers, harm future negotiations and harm ratepayers. OPG stated that these data are not high level summaries. OPG referred to the applicability of Appendix B subsections (a) i, ii and iv, and (b) of the Practice Direction regarding confidential treatment for this information. OPG stated that it has publicly communicated a range or bounded estimate of the project cost and LUEC, which OPG stated will permit full review of the issues.

2. The second category of information relates to cost and contingency for project specific components. OPG stated that this information would give suppliers an advantage in future bids and ultimately be detrimental to ratepayers.

**Business Plan**
SEC noted its concern with ongoing redactions in the unredacted versions of the Business Plan, and stated that this filing was contrary to the Board's rules. OPG replied that the redactions in the Nuclear Business Plan relate to Canadian Electrical Association ("CEA") safety statistics. The CEA information is provided to OPG on the basis that it not be disclosed. The ongoing redactions in the Hydroelectric Business Plan relate to the unregulated facilities. As this is irrelevant to the payment amounts proceeding, OPG has continued to redact the information.

**Decision**
The Board finds that it is appropriate to retain the confidential status of the Tax Information for the reasons OPG provided with its application. As noted above, no parties objected to confidential treatment.

There are 34 redacted BCS, and the Board finds that it is appropriate to retain the confidential status of all these documents. While parties provided submissions opposing confidential treatment for the Niagara Tunnel BCS, the Board notes that OPG has not requested cost recovery of that project in this application. Parties also provided submissions opposing confidential treatment for the Darlington Refurbishment. The Board finds that it is appropriate to retain the confidential status at this time, however, the Board may reconsider this protection as the review of CWIP for Darlington Refurbishment progresses.

With respect to the continued redactions within the Business Plans, the Board finds that the benchmarking data will not be redacted from the confidential version of the Nuclear Business Plan. The Board is of the view that its practices related to the handling of confidential material are sufficient to alleviate any concerns which the CEA may have in respect of its benchmarking studies.

With respect to the redactions in the Hydroelectric Business Plan related to the unregulated business, the Board finds that these redactions from the confidential version of the exhibit are acceptable. Some parties have questioned whether in fact the redactions are limited to the unregulated business. To address this concern the Board will require OPG to file a fully unredacted version of the Hydroelectric Business Plan so that the Board may examine and determine whether the redactions are appropriate. This document will not be made available to the parties. The Board will issue correspondence to all parties following that review, and the Board will return the unredacted copy to OPG.

## Issues List

### Introduction

Submissions on the revised draft issues list were received from the following parties: OPG, SEC, the Power Workers' Union ("PWU"), Pollution Probe, AMPCO, Energy Probe Research Foundation ("Energy Probe"), CCC, the Vulnerable Energy Consumers Coalition ("VECC"), the Green Energy Coalition ("GEC"), and CME. The submission from CME was filed late and it consisted of submission on the issues, as well as reply on OPG's submission. VECC limited its submission to stating that the issues list encompassed the issues VECC intended to pursue in interrogatories. GEC limited its submission to stating that it had no concerns with the issues list.

Reply submissions were received from OPG, GEC, AMPCO, VECC and SEC. The Board has considered all submissions and reply submissions in establishing a final issues list which is attached as Appendix A. These are reviewed below, and referred to where required, along with the Board's rationale in addressing each of these requests.

### Issues

### 1. GENERAL

1.1 Has OPG responded appropriately to all relevant Board directions from previous proceedings?

SEC suggested that the directions from the prior decisions could be listed on an individual basis, but agreed that all the directions are captured under issue 1.1.

The Board does not believe it is necessary to list the directions from prior decisions, and will not alter the wording of this issue.

1.2 Are OPG's economic and business planning assumptions for 2011-2012 an appropriate basis on which to set payment amounts?

It is OPG's position that the issue should not be on the list as the establishment of economic and business planning assumptions is the role of OPG management and not the role of the Board. In reply submission, SEC pointed out that this issue is a standard issue for most rate applications. Both GEC and SEC argued that the Board's role does include a review of the planning assumptions of OPG management as part of determination of just and reasonable rates.

The Board agrees that the establishment of economic and business planning assumptions is the role of OPG management. However, it is appropriate for the Board to review and understand those economic and business planning assumptions as these are the starting points for the proposals put forth in the application. Accordingly, issue 1.2 will remain on the issues list.

SEC submitted that another general issue should be included: *Would the disclosure and treatment in the Application of the impact of the transition to International Financial Reporting Standards be consistent with the Report of the Board dated July 28, 2009 in EB-2008-0408, if that Report expressly applied to the Applicant? To the extent that there are any differences between the reporting from the Applicant and the reporting contemplated in the Board's Report, what are those differences, and what steps, if any, should be taken to deal with those differences?*

In reply submission, OPG referred to the Board's Filing Guidelines for this application which provided OPG with the option of filing in Canadian Generally Accepted Accounting Principles ("CGAAP") or modified IFRS based format. OPG also stated that it does not have the information SEC is requesting as revenue requirement was only developed under CGAAP. OPG also pointed to delays in guidance from the International Accounting Standards Board ("IASB"), and delays in finalizing its own accounting policies and treatments under IFRS.

The Board will not add the IFRS issue suggested by SEC. OPG's application was filed in accordance with the Filing Guidelines. OPG chose to file based on CGAAP, and as the IASB guidance for rate regulated entities has been delayed the Board believes filing based on an IFRS format is premature.

## 2. RATE BASE

2.2 Is OPG's proposal to include CWIP in rate base for the Darlington Refurbishment Project appropriate?

AMPCO proposed that the issue be restated to replace "CWIP" with "accelerated cost recovery", however, no explanation was provided. OPG opposed the wording change, noting that the proposal was vague and that CWIP was straightforward.

The Board is satisfied with the phrasing of issue 2.2. If AMPCO wishes to query alternatives to CWIP, it may do so through interrogatories.

## 3. CAPITAL STRUCTURE AND COST OF CAPITAL

3.3 Should the same capital structure and cost of capital be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure and/or cost of capital parameters are appropriate for each business?

Pollution Probe submitted that the wording is appropriate and compatible with the Board's previous decision. However, Pollution Probe also stated that "although the Board stated some intentions and expectations regarding the issue's likely focus and development, those comments did not appear to be determinative in a final sense for this proceeding." Pollution Probe sought confirmation from the Board of its understanding. In its reply submission, OPG stated that it was unsure what Pollution Probe meant in its submission. However, OPG accepted the wording of issue 3.3.

The Board's finding in the previous proceeding (EB-2007-0905) on separate capital structures for the regulated hydroelectric business and the nuclear business is found on page 161 of the decision with reasons.

> The Board concludes that this is an approach worthy of further investigation which will be explored in OPG's next proceeding. In examining whether to set separate costs of capital, the Board intends only to examine whether separate capital

> structures should be set for the regulated hydroelectric and nuclear businesses. The Board expects that the same ROE would be applicable to both types of generation. This is consistent with the general approach of setting a benchmark ROE and recognizing risk differences in the capital structure.

While the decision is clear that the Board's intention was to review capital structure, and not return on equity, it remains open to a party, including Pollution Probe, to file evidence on separate capital structures and ROEs in this proceeding.

SEC submitted that another section 3 issue should be included: *Should a formula be adopted by the Board to adjust the Applicant's cost of capital for prescribed facilities annually and, if so, what should that formula be?*

OPG opposes the addition of this new issue. In its reply, OPG stated that the last payment amounts decision "agrees that the adoption of a formula approach to setting ROE is appropriate in the circumstances." For this test period, OPG has adopted the Board's Cost of Capital Report (EB-2009-0084) for the determination of ROE.

The Board will not add SEC's proposal as a separate issue, as it is subsumed in issues 3.1 and 3.2. In addition, if parties wish to test OPG's proposal of establishing one set of cost of capital parameters for both test periods, they may do so through interrogatories and in the course of this proceeding.

## 4. CAPITAL PROJECTS

4.1 Do the costs associated with the regulated hydroelectric projects, and proposed for recovery, meet the requirements set out in O. Reg. 53/05? If not, were the additional costs prudent?

OPG submitted that the issue should be restated as: *Do the costs associated with the regulated hydroelectric projects, that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?* OPG believes that the reference to section 6(2)4 provides clarity. OPG also states that the question of prudent costs is subsumed within section 6(2)4. OPG points out that section 6(2)4 contemplates a prudency review by the Board if the costs were not approved by OPG's Board of Directors prior to the Board's first order.

SEC did not object to OPG's proposed wording, as long as the prudence of additional costs was subject to review.

The Board accepts OPG's proposed restatement of the issue, and notes that the structure of the Regulation confirms that a Board finding of prudence is required for any incremental costs. The final version of issue 4.1 is: Do the costs associated with the regulated hydroelectric projects, that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?

4.2 Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

OPG submitted that the issue should be restated as: *Are the capital budgets for 2011 and 2012 for the regulated hydroelectric business reasonable and supported by business cases where specified in the Filing Guidelines established in EB-2009-0331?*

OPG added the reference to the Filing Guidelines because the application provides capital budgets for projects whether they close to rate base or not. The Filing Guidelines only specify provision of business case summaries for projects in excess of $10 M. OPG proposed replacing "appropriate" with "reasonable". OPG referred to page 44 of the EB-2006-0501 Hydro One decision where, in the case of projects not closing to rate base, the Board's consideration is limited to the observation that the capital budget is reasonable. Accordingly, expenditures on these projects are not subject to a review based on prudence. OPG stated that it, "wishes to be clear that this issue should not be included if its inclusion is to provide an indirect means of subjecting projects that do not impact the test period payment amounts to a prudence review. As the OEB has recognized, prudence must be examined retrospectively."

The reference to financial commitments has been deleted because, other than projects that are subject to section 6(2)4, OPG does not believe there are any specific implications of financial commitments in the context of an evaluation of the reasonableness of capital budgets.

AMPCO, SEC, CCC and CME filed submissions on this issue. AMPCO proposed an alternate wording: *Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate?* AMPCO submitted that the word "appropriate" should not be modified by reference to business cases. With respect to the Niagara Tunnel Project, AMPCO stated that, "A review in the nature of a status update is required." In its reply submission AMPCO agreed with OPG's position that a prudence review is not the subject of this hearing. AMPCO stated that, "A thorough review of these issues could still take place to assist the Board in determining the reasonableness of OPG's capital budgets."

SEC submitted that, if the review of the Niagara Tunnel Project is encompassed within this issue then SEC has no concerns. If not, then a separate issue should be included in dealing with this project, as the earlier this project is looked at, the better. In its reply submission, SEC stated that for large multi year projects, as more costs are incurred, it becomes more difficult for the Board to deny recovery. SEC questioned OPG's position and whether it wanted to hear the Board's comments and concerns.

CCC submitted that if projects do not come into rate base during the test period but form part of the capital budget, the costs should be considered in the scope of the proceeding. CME stated that prudence falls within the ambit of matters pertaining to appropriateness and reasonableness, and submitted that OPG's proposed changes are inappropriate.

OPG replied that if AMPCO, SEC, CCC and CME are seeking only a status update on the Niagara Tunnel, OPG would have no dispute. The inquiry that OPG believes is inappropriate in this proceeding is a prudence review of the project's cost and performance. OPG stated that it is unproductive to assess prudence mid stream when costs and performance are still unknown. OPG stated that undertaking a prudence review of the Niagara Tunnel in this proceeding would effectively put the Board in the position of managing OPG's affairs. OPG noted that while the capital expenditures are large, there is no impact on OPG's financial viability or the safe, reliable provision of electricity.

In support of its position, OPG referred to the EB-2006-0501 Hydro One proceeding where Hydro sought assurance from the Board that the capital program was appropriate, subject to coming back at a later date to demonstrate that costs were reasonable and prudent. In that proceeding VECC submitted that the Board should not grant the assurance, and that any such conclusion should be no more than an observation. The Board agreed with VECC, that the costs of the Hydro One projects would be subject to approval in a future proceeding.

The Board will retain the current statement of issue 4.2 including the term "appropriate" and the reference to business cases. The Board will only make prudence determinations with respect to projects or costs that close to rate base in the test period. While the Board agrees that it would be appropriate to review other aspects of the capital budgets, the Board expects that this review will be more in the form of a status update. The Board does not intend to make any form of quantitative or qualitative finding with respect to projects and costs which close to rate base in the period after the test period.

4.4 Do the costs associated with the nuclear projects, and proposed for recovery, meet the requirements set out in O. Reg. 53/05? If not, were the additional costs prudent?

Submissions on this issue were the same as for issue 4.1. The Board will adopt the same approach for this issue as for issue 4.1. The wording of the issue will be: Do the costs associated with the nuclear projects, that are subject to section 6(2)4 and 6(2)4.1 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?

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

Submissions on this issue were the same as for issue 4.2. Likewise, the Board will retain the current statement of issue 4.5.

The draft issues list attached to Procedural Order No. 1 contained an issue 4.8 related to new nuclear expenditures and an issue 4.9 related to nuclear refurbishment expenditures. These issues were not included in the revised draft issues list attached to Procedural Order No. 2. Pollution Probe seeks confirmation that former issues 4.8 and 4.9 are subsumed in other capital project issues.

The Board confirms that former issues 4.8 and 4.9 are subsumed in other capital project issues.

## 5. PRODUCTION FORECASTS

5.1 Is the proposed regulated hydroelectric production forecast appropriate?
5.2 Is the estimate of surplus baseload generation appropriate?

OPG submitted that issue 5.2 should not be included because it is subsumed in issue 5.1. Surplus baseload generation is just one of the inputs used to determine the production forecast.

CME made a submission on a group of subsumed issues, with issue 5.2 as one of that group. CME submitted that no harm ensues by leaving the item on the list, and that it could lead to more organized presentation of interrogatories and the associated responses.

In reply submission, SEC stated that the issue was helpful, but agreed that it was part of issue 5.1.

The Board agrees that issue 5.2 is subsumed in issue 5.1 and will therefore remove issue 5.2.

5.3 Is the proposed nuclear production forecast appropriate?
5.4 Are the estimates of fleet level uncertainty and forced loss rates for the individual nuclear plants reasonable?

Submissions on issue 5.4 were similar to those for issue 5.2. The Board agrees that issue 5.4 is subsumed in issue 5.3 and will therefore remove issue 5.4.

## 6. OPERATING COSTS

6.1 Is the test period Operations, Maintenance and Administration budget for the regulated hydroelectric facilities appropriate?

The PWU submitted that the issue should be restated as: *Are OPG's proposed budgets for Operations, Maintenance and Administration in 2011 and 2012 for its regulated hydroelectric facilities appropriate, including consideration of service reliability and asset condition?*

The PWU stated that the appropriateness of the costs must be reviewed relative to service performance in addition to bill impacts. In its reply submission, SEC stated that the proposed amendments do not appear to add anything as consideration of service reliability and asset condition are normal parts of the analysis.

The PWU has noted only two of many factors that are considered in the assessment of an OM&A budget. The Board will therefore retain the current statement of issue 6.1 so that it is clear that all relevant factors should be considered.

6.2 Are the benchmarking results and targets flowing from those results for OPG's regulated hydroelectric facilities reasonable?

OPG submitted that the issue should be restated as: *Are the benchmarking results for OPG's regulated hydroelectric facilities reasonable?* OPG stated that the setting of business targets is the responsibility of OPG's management and not the Board. Further, the setting of business targets is based on many factors including benchmarking, and for these reasons, OPG's proposed issue has removed the reference to targets.

AMPCO proposed the following additional issue: *Is OPG's benchmarking methodology appropriate?* AMPCO stated that it would be necessary for the Board to understand the analysis and the judgments which underpin the analysis such as the criteria for the selection of cohorts. In AMPCO's reply submission, it noted its disagreement with OPG's proposed issue, and confirmed its position that a full review of benchmark methodology is an essential part of the hearing.

CCC stated its expectation that the scope of the issue is to what extent the benchmarking results should be used in determining OPG's overall revenue requirement. CCC was not clear what was meant by the wording, "flowing from those results."

In response to the submissions of AMPCO and CCC, OPG replied that payment amounts are based on forecast cost and production, and that benchmarking assists with assessment of reasonableness of the forecasts.

In reply submission, SEC noted that if the Board is only looking at the benchmarking, and not what OPG is doing about it, it may be just wasting its time. SEC agreed that the setting of business targets is the responsibility of OPG management. However, SEC stated that the review of the targets for reasonableness and prudence is the Board's responsibility and a necessary issue in the proceeding.

The Board considers the review of benchmarking an important aspect of the OPG proceeding. It is appropriate to review methodology, results and targets. The final version of issue 6.2 is: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's hydroelectric facilities reasonable?

6.3 Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

The PWU made the same submission on this issue as for issue 6.1. For the same reasons, the Board will retain the current statement of issue 6.3.

In its submission, SEC proposed two additional OM&A issues related to Pickering:

*To what extent, if any, should the OM&A included in rates for the Pickering units be based on benchmark costs as opposed to forecast costs? If any benchmark costs are to be used, what benchmarking information is available and appropriate for application to revenue requirement in the Test Period?"*

*Does the Applicant have a viable plan to produce electricity from Pickering A and Pickering B at an overall reasonable cost over their remaining lives?*

In its reply position, OPG stated that SEC is trying to re-litigate its proposals on benchmarking and Pickering A viability from the last proceeding. OPG stated that the Board rejected these requests in the last proceeding and that SEC's proposed additions to the issues list should be rejected.

The Board will not add the two issues proposed by SEC. The Board finds that these matters are within the scope of the current proceeding, but the specific issues are subsumed in issues 6.3 and 6.4.

6.4 Are the benchmarking results and targets flowing from those results for OPG's nuclear facilities reasonable?

Submissions on this issue were the same as for issue 6.2. For the same reasons, the final version of issue 6.4 will be: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's nuclear facilities reasonable?

6.5 Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

OPG submitted that the issue should be restated as: *Has OPG responded appropriately to the recommendations in the benchmarking report?* OPG stated that the focus should be on the recommendations, not the observations themselves.

CME replied that OPG's revision is unnecessary. In reply submission SEC stated that the suggestion that observations simply cannot be considered by the Board at all is not a reasonable one.

The Board notes that the Phase 1 benchmarking report provided only observations comparing OPG to comparators. Hence, removal of "observations" might imply that that the results of the Phase 1 report were out of scope. Accordingly, the Board will retain the current phrasing of issue 6.5.

6.9 Are the "Centralized Support and Administrative Costs" (which include Corporate Support and Administrative Service Groups, Centrally Held Costs and Hydroelectric Common Services) and the allocation of the same to the regulated hydroelectric business and nuclear business appropriate?

OPG submitted that the issue should be restated as: *Are the "Centralized Support and Administrative Costs" (which include Corporate Support and Administrative Service Groups, Centrally Held Costs and Hydroelectric Common Services) allocated to the regulated hydroelectric business and nuclear business appropriate?* OPG stated that this wording tracks the wording used in the last payments case and the issue has not, in substance changed.

SEC submitted that two new issues related to corporate costs should be added to the list: *Is the Applicant's response to the Board's direction in the First Payment Amounts Decision, to file an independent review of its corporate cost allocations, appropriate? Is it appropriate to make any changes to the corporate cost allocations proposed by the Applicant in light of the Applicant's response to the direction?*

In the previous case, intervenors requested a variance account for Regulatory Affairs costs because they were expected to be lower in the period following. The request was denied. SEC believes that an issue should be added to deal with the combined result of a lack of a variance account and the Extension Decision (EB-2009-0174), and whether it should affect any amounts ordered in this proceeding.

CCC submitted that it assumed that the issue includes assessment of the level of costs and methodology to allocate the costs. In its reply, CME stated that OPG's rewording is unnecessary, but non substantive. VECC replied to the submissions for OPG and CME. VECC stated that OPG's proposed change narrows the issue and would make costs out of scope and only relate to allocation methodology. CME subsequently filed correspondence that supported VECC's position. SEC's reply submission was similar to VECC's.

OPG replied that SEC's proposed issue relating to the review of corporate cost allocation is unnecessarily complex. OPG stated that its proposed wording is consistent with CCC's submission that the issue should include an assessment of both the level of costs and the methodology to allocate them.

With respect to SEC's proposed issue related to Regulatory Affairs costs, OPG stated the test period costs can be reviewed under issue 6.9. OPG noted that the Board declined to establish a variance account for Regulatory Affairs costs in EB-2007-0905 and that the Board rejected SEC's request to examine OPG's 2010 costs in the Accounting Order for 2010 (EB-2009-0174).

The Board finds that the current phrasing of the issue adequately encompasses both the quantum of corporate costs and the allocation of the corporate costs.

## 7. OTHER REVENUES

7.1 Are the proposed test period regulated hydroelectric business revenues from ancillary services, segregated mode of operation and water transactions appropriate?
7.2 Are the proposed test period nuclear business non-energy revenues appropriate?

SEC submitted that the Board should confirm that a review of the appropriateness of continuing to use a three year average for SMO and WT revenues and that a review of the actuals, including 2010, relative to the imposed forecast, are included in issue 7.1.

SEC also noted that in the first decision, the Board refused to include Congestion Management payments as a revenue offset. SEC would like to explore the ROE in a past year, with and without the Congestion Management payments and the constrained on or off situations that caused them. SEC wants to explore what costs, if any, of being constrained are included in the forecast revenue requirement, and, if they are, whether the payments should also be included, or whether the costs should be taken out of revenue requirement, in either case to achieve symmetry. If this is included in issue 7.2, SEC is not concerned. If it is not, SEC would like to add an issue dealing with the appropriateness of congestion management payments being a revenue offset.

OPG replied that SEC seeks to re-litigate the Board's rejection of its position in the last proceeding. CMSC are not incremental revenue, but compensation for lost revenue and unforecast costs of operational changes imposed by the IESO. SEC points to no new circumstances that warrant review of CMSC.

The Board agrees with SEC that an examination of the costs and revenues associated with Congestion Management payments is within the scope of issue 7.2, as is any other potential revenue offset. Although the Board did not include Congestion Management payments as a revenue offset in the last proceeding, it is open to parties to re-visit this issue if there is a reasonable expectation of additional relevant evidence which should be considered.

## 8. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

8.1 Is the revenue requirement methodology for recovering nuclear liabilities in relation to nuclear waste management and decommissioning costs appropriate? If not, what alternative methodology should be considered?

OPG submitted that the issue should be restated as: *Has OPG appropriately applied the revenue requirement methodology for recovering nuclear liabilities in relation to nuclear waste management and decommissioning costs approved by the OEB in EB-2007-0905?*

OPG stated that in developing and approving its own revenue requirement treatment for the nuclear liabilities associated with Pickering and Darlington in EB-2007-0905, the Board rejected requests that the approved methodology be labeled interim. OPG has based its requested payment amounts on the methodology established by the Board. The last decision noted that if other regulatory bodies issue decisions addressing asset retirement obligations ("ARO") prior to the next payment amounts proceeding, then OPG and other parties would have an opportunity to revisit the issue, but no such external events have occurred to warrant revisiting this issue. OPG states that there is no reason to re-open this issue in this proceeding.

AMPCO, SEC and CME supported retaining the issue as originally worded. AMPCO noted that, "The Issues List should allow an opening because the passage of time has appeared to allow for the development of other relevant precedents." In its reply, AMPCO submitted that the original wording should be retained. CME stated that, "Parties are always at liberty to explore the same issue in consecutive proceedings." SEC submitted that methodology is a live issue and cited IFRS and the consideration of ARO by FERC in support of its position. SEC proposed adding the following to issue 8.1: *Have any regulatory or other bodies issued position or policy papers, or made decisions, with respect to Asset Retirement Obligations that the Board should consider in determining whether to retain the existing methodology or adopt a new or modified methodology?*

In reply submission, OPG noted that SEC and CME recognized that the issue of methodology would be revisited if other regulatory bodies issued decisions relating to ARO. OPG stated that CME has not indicated if it is aware of such decisions or had searched for them. In relation to SEC's submission, OPG stated that IFRS has no bearing on the issue as the application has been filed on a CGAAP basis. SEC stated that ARO has been considered at FERC, but OPG is not aware of new ARO developments at FERC. AMPCO stated that "the passage of time has appeared to allow for the development of other relevant precedents" but didn't provide any.

SEC suggested that there should be a new issue related to the Ontario Nuclear Funds Agreement ("ONFA") Reference Plan. SEC noted that ONFA requires a new Reference Plan no later than December 2011. In SEC's view the possibility of a change to the plan should be included in the nuclear liabilities issues. Energy Probe made a similar submission.

OPG replied that it continues to operate under the existing reference plan. The new plan will not be in place for a year and an issue should not be added to the list.

The Board does not agree with OPG's position that this matter is closed from the outset. The decision from the previous case stated:

> Before the hearing on OPG's next payment amounts application is completed, the National Energy Board, Provincial regulatory bodies, FERC, or other bodies may issue position or policy papers or release decisions dealing with AROs. If such external developments occur, OPG, intervenors, and Board staff will have the opportunity in that hearing to submit evidence and argue for a different approach to AROs.

It is open to parties to explore whether there have been any developments in this area and any party may file evidence on AROs in this proceeding. The Board finds that SEC's proposed phrasing of the issue is appropriately focused on new and modified methodologies and precludes methodologies reviewed in the last proceeding. Accordingly, the final issue 8.1 is: Have any regulatory or other bodies issued position or policy papers, or made decisions, with respect to Asset Retirement Obligations that the Board should consider in determining whether to retain the existing methodology or adopt a new or modified methodology?

The Board finds that queries on the ONFA Reference Plan do not require a separate issue and may be asked under issue 8.2.

8.2 Is the revenue requirement amount for nuclear liabilities related to nuclear waste management and decommissioning costs appropriately determined?

Energy Probe's submission under issue 8.2 is noted in issue 8.1 above.

SEC submitted that there is a 2.23 million bundle threshold for used fuel management liability, which at one time was forecast to be reached in 2011. Unless the effect of this is already in Issue 8.1 or 8.2, SEC believes that an issue should be added dealing with the potential impact of this, as follows: *Has the liability threshold for the Applicant on used fuel bundles, 2.23 million bundles, been reached or will it be reached in the test period? If so, what are the implications on the liability for, and revenue requirement of, nuclear waste management?* OPG replied that the submission from SEC is in the form of an interrogatory and should not be included in the issues list.

The Board finds that SEC's proposed issue is subsumed in issue 8.2

## 9. DESIGN OF PAYMENT AMOUNTS

9.1 Is the design of regulated hydroelectric and nuclear payment amounts appropriate?

OPG submitted that the issue should not be included on the list because the matter was decided in the last proceeding. CCC supports the inclusion of issue 9.1. While CCC is not proposing a different design at this time, it would like to leave open the possibility. CME submitted that no harm ensues by leaving issue 9.1 on the list. In reply submission, SEC stated that the structure of payment amounts does not only come into play because OPG wants it considered. It also arises as a matter of law because of the Board's statutory mandate to se these rates.

The Board agrees with the submissions of CCC, CME and SEC and finds that it is appropriate to have a general payment amount design issue.

9.2 Is the hydroelectric incentive mechanism appropriate?

OPG submitted that the issue should be restated as: *Has the hydroelectric incentive mechanism encouraged appropriate operating decisions? If not, how should the incentive mechanism be modified?* OPG stated that in the last proceeding the Board instructed OPG to report back on the impact of the incentive structure on OPG's operating decisions. OPG's position is that the focus of the Board's inquiry in this proceeding should be on the operation of the approved hydroelectric mechanism. Only if that mechanism is found to be deficient, should modifications be considered.

SEC submitted that the issue should be restated as: *Has the Applicant responded appropriately to the Board's direction in the First Payment Amounts Decision to file a review of the incentive mechanism? Has the incentive produced the results intended by the Board? What changes, if any, to the incentive mechanism are appropriate in light of the experience to date?* SEC also submitted a new issue on mitigation: *To what extent, if any, should the Applicant implement mitigation of any rate increases determined by this Board? If mitigation should be implemented, what is the appropriate mechanism that should be used?* This second issue is addressed along with CME's issue related to Consumer Impacts and Affordability.

In reply submission, AMPCO stated that it preferred the broader wording rather than changes suggested by OPG. CME replied that OPG's proposed rewording was non-substantive. VECC replied to the submissions of OPG and CME. OPG's rewording suggests that only if the incentive failed could the Board entertain changes. In VECC's view the appropriate issue is the appropriateness of the methodology, leaving open the issue of whether it is required at all. CME subsequently filed correspondence that supported VECC's position.

OPG replied that SEC's proposed wording is cumbersome and that the Board should adopt the issue proposed by OPG in its initial submission.

On this issue, SEC replied that there is no point in reviewing the incentive mechanism if the question of whether the mechanism is appropriate is off the table. The Board's intention was that the new mechanism would be subjected to scrutiny in this proceeding, and the Board should ensure that is the case.

The Board finds that the issue as phrased is sufficiently broad to enable all the parties to query the topic of hydroelectric incentive mechanism.

## 10. DEFERRAL AND VARIANCE ACCOUNTS

10.1 Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

SEC submitted that it does not appear that the Review Decision (EB-2009-0038) was in a position to consider whether there would be an impact on the baseline calculated for the purposes of the Income and Other Taxes Variance Account. SEC seeks confirmation that interrogatories on this matter are included under issue 10.1. In reply, OPG submitted that this question is captured under issue 10.1

The Board agrees that the matter is captured under issue 10.1.

10.2 Is the proposed inclusion of costs related to Pickering B continued operations in the Capacity Refurbishment Variance Account appropriate?

OPG submitted that issue 10.2 should not be included on the list because it is a sub-issue of issue 10.1. CME submitted that no harm ensues by leaving this issue on the list. In reply submission, SEC noted that, while this issue is probably included in issue 10.1, SEC believes it is useful to keep it as a separate issue.

The Board finds that issue 10.2 is subsumed in issue 10.1 and it will be removed from the final Issues List.

10.3 Are the balances for recovery in each of the deferral and variance accounts appropriate?
10.4 Is the disposition methodology appropriate?
10.5 Is the proposed continuation of deferral and variance accounts appropriate?

SEC submitted that it is not obvious that changes to the terms of existing deferral and variance accounts are included in issue 10.5. SEC proposed adding the following to the end of issue 10.5: *What changes, if any, should be made to the terms of any deferral or variance accounts that are continued?* OPG replied that the addition is unnecessary as "it is beyond dispute that the Board in approving accounts, whether new or continued, may change their terms prospectively."

The Board finds that SEC's proposed issued is subsumed in issue 10.5.

SEC made a number of proposals for additional issues. The Board finds that all of SEC's proposed issues, with the exception of the ones noted below, are subsumed under issues 10.3 and 10.4.

In its submission, SEC proposed two new issues on the impact of the Extension Decision: (1) In its letter of August 18, 2009 in relation to EB-2009-0174, the Board said, in denying earnings sharing for 2010, "CME may wish to raise at the next payments proceeding the issue of OPG's 2010 results, and whether those results should be considered in the disposition of the deferral and variance accounts". SEC noted that it is unable to determine if any of the issues on the draft list include this. If it is not included, SEC believes that a specific issue should be added which has sufficient scope to consider forecast earnings by OPG on the prescribed facilities in 2010.

(2) SEC also proposed a new issue on reviewing the necessity to capture 2010 variances relating to SMO or WTs. In the First Payment Amounts Decision, the Board decided, at page 49, not to order a variance account for revenues relating to SMO or water transactions. In light of the Extension Decision, SEC is concerned with whether

something is needed to capture 2010 variances, and whether going forward a new variance account should be added for this purpose given the potential for additional extensions.

In reply submission, OPG stated that SEC made a specific request to review 2010 earnings in the EB-2009-0174. OPG stated that the Board rejected the request. OPG stated that the two issues requested by SEC above, are requests to review 2010 earnings "under the guise of a variance account review." OPG stated that the draft issues list fully covers appropriate review of deferral and variance accounts, and that a general review of 2010 earnings "is precluded by the prohibition against retroactive ratemaking."

With respect to the first issue proposed by SEC, the Board finds that an additional issue is not required. Parties can pursue the line of enquiry contemplated by the Board in its letter of August 18, 2009 under the existing issues. With respect to the second proposal, the need for new accounts to capture variances in the period beyond the current test period may be reviewed under issue 10.7 and that review may include an examination of circumstances in 2010. However, the Board will not be reviewing 2010 with a view to retroactively imposing variance accounts where none were originally ordered.

## 11. REPORTING AND RECORD KEEPING REQUIREMENTS

11.1 What reporting and record keeping requirements should be established for OPG?

OPG submitted that issue 11.1 should not be included on the list because a proceeding on OPG's application for payment amounts is not the appropriate forum for establishment of RRRs. OPG stated that evidentiary requirements for RRR were not included in the Filing Guidelines. Including RRR issue may lead to delays and inefficiencies as OPG may require an opportunity to prepare and file evidence. OPG suggested that a separate proceeding, as was done with the gas and electric distributors, should be initiated if the Board decides to consider RRRs for OPG.

CME submitted that no harm ensues by leaving this issue on the list. AMPCO replied that it disagreed with OPG. AMPCO suggested that the issue might best be dealt with by written submission, but should remain part of the proceeding. In its reply, SEC noted that OPG argues for a separate, presumably generic, proceeding for RRR. As OPG is the only generator whose payment amounts are regulated, it appears to SEC that a separate proceeding is not necessary as it would have no generic aspect to it.

The Board agrees with the parties that a consideration of future reporting requirements is appropriately conducted in the current proceeding, and the issue will remain. The Board does not expect to receive evidence in addition to what is contained in OPG's application. It is the Board's expectation that there will be interrogatories and argument on the matter.

## 12. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

12.1 What incentive regulation formulations and options should be considered?
12.2 When would it be appropriate for the Board to establish incentive regulation, or other form of alternative rate regulation, for setting payment amounts?
12.3 What issues will require further examination to establish appropriate base payment amounts as the starting point for an incentive regulation or other form of alternative rate regulation plan?
12.4 What processes should be adopted to establish the framework for incentive regulation, or other form of alternative rate regulation, that would be applied in a future test period?

OPG submitted that none of the issues in section 12 should be included. OPG submitted that the Board should convene a separate proceeding to determine an appropriate alternative regulatory mechanism ("ARM") for OPG, the information necessary to implement the approved mechanism and the appropriate starting point for the payment amounts based on the specific ARM selected. The ARM proceeding could commence soon after the issuance of the OEB's final order.

OPG stated that it is premature, inconsistent, inefficient and unfair to include the issue of IRM in this proceeding. IRM was not raised in the notice for the filing guidelines consultation, nor was it present in the staff Scoping Paper and was never discussed in the consultation itself. In its submission, OPG provided a list of parties who participated in the 2006 payment amount methodology consultation, but who are not parties in the current proceeding.

OPG has not filed evidence on this issue. Including this issue would cause serious delays, requiring OPG and perhaps other parties, to develop and file evidence. This may take several months. OPG stated that the IRM methodology should be established in the context of the business environment that OPG's prescribed facilities will face over the next five years. This context is not considered in the current application, which extends only to the end of 2012.

The PWU strongly recommended the removal of issue 12. Given the ambitious schedule of this proceeding, the efforts required in properly considering these issues would not be doable within this proceeding. The Board should initiate a separate consultation process.

CCC submitted that the consideration on IRM formulation and options should not be considered in this proceeding. However, CCC sees values in maintaining issue 12.4 on the list so parties can make submissions at the time of final argument regarding the nature and time frame for a separate process.

AMPCO submitted that this issue is best dealt with by way of written submissions and argument. If fully considered in this proceeding, this issue might divert the focus from other elements of the proceeding.

SEC submitted that this issue should remain on the list. While the Board may determine that the appropriate result is some form of consultation process and Board policy paper, the issue should still remain on the issues list for the Board to consider all of its options. SEC noted that at the very least, "the Board will have to consider in setting payment amounts for the test period whether those payment amounts will form the basis for IRM, or whether, as has already happened once, the Applicant may simply fail to seek new payment amounts for some period of time after the current test period."

CME suggested a more general issue: *What process for determining how and when OPG should be transitioned to Incentive Regulation is appropriate?* CME suggested that parties would be free to pose interrogatories of OPG. CME suggested that this matter could be considered at the Settlement Conference.

OPG replied that SEC's proposal reverses the logical order for developing an ARM and stated that SEC offered no persuasive reason why these issues should be considered in this proceeding rather than an ARM proceeding. OPG stated that CME suggested a reworded issue so that CME can pose interrogatories on matters on which OPG has not submitted evidence or developed a position. OPG's position is that a separate ARM proceeding is more effective.

In reply, SEC stated that the Board should focus on "is now the time". SEC agreed that it is unlikely that this proceeding will result in an IRM system for OPG payment amounts. However SEC suggested placing preconditions on future extensions of this decision – again referring to the last 2008-2009 cost of service which extended to 2010. SEC believes the issues should be retained but with the understanding that the Board may make a more narrowly focused decision.

The Board has decided to narrow the scope of the IRM related issues. The Board accepts that an IRM framework for OPG will not result from this hearing, and does not wish to trigger the filing of extensive expert evidence, or otherwise see disproportionate amounts of hearing time spent on this issue.

The Board is interested, however, in considering what next steps might be appropriate with respect to OPG and IRM. The Board indicated an interest in this issue in the first OPG payments case, and is interested in exploring the issue further in the current case. In that light, draft issues 12.2 and 12.4 will form part of the final issues list. The Board expects that these issues can reasonably be accommodated within the current proceeding.

**Consumer Impacts and Affordability**

In its submission, CME proposed a new issue and sub-issues related to consumer impacts and affordability. CME noted that OPG has provided pre-filed evidence on consumer impact. The proposed issues are:

1. *Are the consumer impacts of OPG's plans appropriate?*
2. *What measures for evaluating consumer impacts and affordability are appropriate?*
3. *What measures to reduce consumer impacts and to enhance affordability are appropriate?*

CME plans to lead evidence on this issue in the Hydro One Transmission proceeding (EB-2010-0002) and is considering the same for this proceeding, pending OPG's responses to interrogatories.

OPG replied to SEC's proposed issue on mitigation (under issue 9.2) and CME's proposed issues. OPG opposes the inclusion of mitigation and consumer impacts issues. OPG states that consideration of impacts occurs after payment amounts are set, then the necessity for mitigation is considered. The consumer bill impact for the current application is 1.7% and well below the Board threshold for mitigation. With respect to the second CME issue, OPG stated that it is impossible to determine what is meant by affordability and how this would be measured in aggregate.

The Board finds that CME's proposed issues will be subsumed within a single issue that will be added to the General category. The issue will be: Is the overall increase in 2011 and 2012 revenue requirement reasonable given the overall bill impact on consumers?

## Procedural Matters

The schedule for filing interrogatories and responses to interrogatories as set out in Procedural Order No. 1 is unchanged. Parties should make every attempt to frame interrogatories on the confidential material such that the interrogatories can be filed on the public record. All interrogatories should refer to an issue on the issues list and to the evidence. In filing the interrogatory responses, OPG shall organize the filing of the responses by issue and within each issue by party.

## Requests for Intervenor and Observer Status

The Association of Power Producers of Ontario ("APPrO") is a registered observer in this proceeding. On July 5, 2010, APPrO informed the Board that it has reconsidered its involvement in the proceeding and that it wished to change its status from observer to intervenor. APPrO stated that it accepts the record to date and that it does not intend to seek an award of costs.

The Society of Energy Professionals (the "Society") filed a Notice of Motion and Letter of Intervention on July 14, 2010. The Society stated that it was filing its intervention request late because OPG did not serve the notice of application on the Society, as directed by the letter of direction. The Society stated that it does not anticipate filing for cost awards. On July 16, 2010, OPG filed correspondence stating that, for the record, the Society had been served the notice of application as required by the letter of direction. OPG also confirmed that it does not oppose the Society being granted intervenor status.

APPrO and the Society are granted intervention status subject to any parties' objection to the late intervention request. The Board will not, however, allow these parties to make submissions relating to any determinations it has already made. The Board finds that the Society is not eligible for cost awards.

On July 19, 2010, the Board received a late request from the Ministry of Energy and Infrastructure for observer status in this proceeding. The request is granted.

An updated list of parties to this proceeding is attached. The Board notes that there are currently two observers for this proceeding, the Ministry of Energy and Infrastructure and the Independent Electricity System Operator.

The Board considers it necessary to make provision for the following matters related to this proceeding. The Board may issue further procedural orders from time to time.

**THE BOARD ORDERS THAT**:

1. The final Issues List (attached as Appendix "A") is approved for this proceeding.

All filings to the Board must quote file number EB-2010-0008, be made through the Board's web portal at www.errr.oeb.gov.on.ca, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties shall use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.oeb.gov.on.ca. If the web portal is not available, parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

## ADDRESS

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON   M4P 1E4
Attention: Board Secretary

E-mail: Boardsec@oeb.gov.on.ca
Tel:  1-888-632-6273 (toll free)
Fax: 416-440-7656

**ISSUED** at Toronto, July 21, 2010

**ONTARIO ENERGY BOARD**

*Original signed by*

Kirsten Walli
Board Secretary

# ATTACHMENT E – NON-CONFIDENTIAL

*Form of Declaration and Undertaking*

## ATTACHMENT E

## Form of Declaration and Undertaking

**EB-2013-0321**

**IN THE MATTER OF** the *Ontario Energy Board Act, 1998*;

**AND IN THE MATTER OF** an Application by Ontario Power Generation Inc. for an order or orders approving payment amounts for prescribed generating facilities commencing January 1, 2014.

## DECLARATION AND UNDERTAKING

I, ______________________, am counsel of record or a consultant for ______________________________________________.

### DECLARATION

I declare that:

1. I have read the *Rules of Practice and Procedure* of the Ontario Energy Board (the "Board") and all Orders of the Board that relate to this proceeding.

2. I am not a director or employee of a party to this proceeding for which I act or of any other person known by me to be a party in this proceeding.

3. I understand that this Declaration and Undertaking applies to all information that I receive in this proceeding and that has been designated by the Board as confidential and to all documents that contain or refer to that confidential information ("Confidential Information").

4. I understand that execution of this Declaration and Undertaking is a condition of an Order of the Board, that the Board may apply to the Superior Court of Justice to enforce it.

### UNDERTAKING

I undertake that:

1. I will use Confidential Information exclusively for duties per formed in respect of this proceeding.

2. I will not divulge Confidential Information except to a person granted access to such Confidential Information or to the Board.

3. I will not reproduce, in any manner, Confidential Information without the prior written approval of the Board. For this purpose, reproducing Confidential Information includes scanning paper copies of confidential Information, copying the Confidential Information onto a diskette or other machine-readable media and saving the Confidential Information onto a computer system.

4. I will protect Confidential Information from unauthorized access.

5. With respect to Confidential Information other than in electronic media, I will, promptly following the end of this proceeding or within 10 days after the end of my participation in this proceeding:

   (a) return to the Board Secretary, under the direction of the Board Secretary, all documents and materials in all media containing Confidential Information, including notes, charts, memoranda, transcripts and submissions based on such Confidential Information; or

   (b) destroy such documents and materials and file with the Board Secretary a certification of destruction in the form prescribed by the Board pertaining to the destroyed documents and materials.

6. With respect to Confidential Information in electronic media, I will:

   (a) promptly following the end of this proceeding or within 10 days after the end of my participation in this proceeding, expunge all documents and materials containing Confidential Information, including notes, charts, memoranda, transcripts and submissions based on such Confidential Information, from all electronic apparatus and data storage media under my direction or control and file with the Board Secretary a certificate of destruction in the form prescribed by the Board pertaining to the expunged documents and materials; and

   (b) continue to abide by the terms of this Declaration and Undertaking in relation to any such documents and materials to the extent that they subsist in any electronic apparatus and data storage media under my direction or control and cannot reasonably be expunged in a manner that ensures that they cannot be retrieved.

7. For the purposes of paragraphs 5 and 6, the end of this proceeding is the date on which the period for filing a review or appeal of the Board’s final order in this proceeding expires or, if a review or appeal is filed, upon issuance of a final decision on the review or appeal from which no further review or appeal can or has been taken.

8. I will inform the Board Secretary immediately of any changes in the facts referred to in this Declaration and Undertaking.

Dated at ______________________________ this ________ day of _________________, _____.

Signature:
Name:
Company/Firm:
Address:
Telephone:
Fax:
E-mail: