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;

AND IN THE MATTER OF Rule 5 of the Rules of Practice and Procedure of the Ontario Energy Board.

NOTICE OF MOTION

Ontario Power Generation Inc. ("OPG") will make a motion to the Ontario Energy Board (the "Board") at its offices at 2300 Yonge Street, Toronto on a date and time to be fixed by the Board.

PROPOSED METHOD OF HEARING: The motion is to be heard either orally or in writing, depending on the manner that permits the Board to deal with this matter most expeditiously given the hearing schedule. .

THE MOTION IS FOR:

(a) An Order excluding from this proceeding the evidence filed by Staff of the Board ("Board Staff") on August 31, 2010, being a report prepared for the Board by Power Advisory LLC titled "Update to Report on Methodologies for Setting Ontario Power Generation Payment Amounts" (the "Power Advisory Report");

(b) An Order excluding from this proceeding all interrogatories and responses to those interrogatories asked in respect of the Power Advisory Report;

(c) An Order prohibiting the attendance of the authors of the Power Advisory Report as witnesses in this proceeding on the matters raised in the Power Advisory Report as suggested in the Board Staff's letter dated August 31, 2010; and,

(d) Such further relief as counsel may advise and the Board permit.

THE GROUNDS FOR THE MOTION ARE:

Background - The Issues List

(a) On June 29, 2010 the Board issued Procedural Order No. 1 in this matter. Attached to the order was a Draft Issues List. Draft issues 12.1-12.4 dealt with the question of incentive regulation for OPG and specifically contemplated (i) the substance of such mechanism (draft issues 12.1 and 12.3) and (ii) the timing and procedure for establishing that mechanism (draft issues 12.2 and 12.4), as follows:

> "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?"

(b) Subsequent to the Issues Conference held on July 6, 2010, and pursuant to Procedural Order No. 1, on July 13, 2010, OPG and certain intervenors filed initial and reply submissions in respect of the Draft Issues List, including submissions in relation to draft issues 12.1-12.4. Board Staff filed neither initial nor reply submissions and as such took no position in the draft issues 12.1 - 12.4;

(c) On July 21, 2010, the Board issued its Decisions and Orders on Confidential Filings and Issues List, and Procedural Order No. 3 (the "Issues List Decision");

(d) In the Issues List Decision, the Board specifically noted OPG's position and that of certain other intervenors:

- "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.

. . .

- 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.

. . .

- 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." [Emphasis original.]

(e) The Board ultimately concluded that:

"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." [Emphasis added.]

(f) Issues 12.1 and 12.2 of the Issues List ask only when it will be appropriate for the OEB to establish incentive regulation, and what processes should be adopted to establish the framework for incentive regulation, that would be applied in a future test period. Board Staff did not seek to amend the Issues List. Board Staff can not now do indirectly that which they chose not to do directly;

The Power Advisory Report

(g) The Power Advisory Report is the result of an RFP (the "RFP") issued by the Board on June 6, 2010;

(h) In the RFP, the Board defined the deliverables for the report as being:

- an update on the methodologies for setting payment amounts including by way of incentive regulation;
- a case study of the methodologies used in other jurisdictions; and
- a review of the review of the implications of the methodologies for Ontario;

(i) Consistent with the RFP, the Power Advisory Report is addressed to the Board and purports to not only evaluate incentives to OPG under the current cost of service methodology for establishing payment amounts, but also purports to survey incentive regulatory mechanisms available to the Board to consider in respect of OPG and evaluate a selected few as to how they may apply to OPG;

(j) The Power Advisory Report does not address:

- when the Board should adopt an incentive regulation mechanism for OPG;
- or what processes should be adopted to establish the framework for incentive regulation;

The Power Advisory Report is Outside the Proper Scope of Hearing

(k) The content of the Power Advisory Report is significantly beyond the scope of approved issues 12.1 and 12.2 of the Issue List. As described above, those issues relate to when and how the Board should establish an incentive regulation mechanism for OPG. They do not deal with the substance of that mechanism;

(l) At the time the Board rendered its Issues List Decision it was aware of the RFP and the scope of the content of the Power Advisory Report.

(m) Similarly, Board Staff was aware of the scope of the content of the Power Advisory Report and chose not to make any submissions in respect of the Draft Issues List;

(n) In removing draft issues 12.1 and 12. 3 from the Issues List - both of which addressed the substance of any incentive regulation mechanism - the Board removed from consideration the very questions addressed by the Power Advisory Report;

(o) The Application and the Issues List established by the Board frame the relevant inquiries in this proceeding. As such, the inquiry undertaken in the Power Advisory Report is beyond the scope of the Issues List and is not relevant to this proceeding;

(p) The issues contemplated in the Power Advisory Report, relate to no part of the application before the Board. If OPG and other parties are required to answer questions on or to reply to the true substance of the Power Advisory Report in this proceeding, for its part, OPG could only do so by filing extensive expert evidence. In addition to the delay that would arise to permit such preparation, a disproportionate amount of hearing time would be spent on issues, which are contrary to the Board's Issues List Decision;

(q) OPG has already indicated in response to interrogatories and technical conference questions its view as to when and how an incentive regulation mechanism should be established. OPG has confirmed that its analysis as to the substance of that mechanism is preliminary and no position has yet been established;

(r) It would be unfair to OPG (and other parties) to have to now answer questions in this proceeding raised by the Power Advisory Report which are beyond approved issues 12.1 and 12.2;

(s) It is also unfair to OPG for the Board to keep as part of the record in this proceeding, interrogatory responses from the authors of the Power Advisory Report that opine or comment on aspects of the report that are outside the scope of the Issues List;

(t) Further, it would be unfair and contrary to the Board's Rules of Practice and the Procedural Orders issued in this matter to permit the authors to testify in respect of their views in relation to approved issues 12.1 and 12.2. These issues do not require any expert technical assistance. These issues are not discussed in the Power Advisory Report. To permit testimony would circumvent the requirement that parties file written evidence in advance of the hearing;

(u) The Board's Rules of Practice and Procedure; and

(v) Such further grounds as counsel may advise and the OEB permit.

THE FOLLOWING DOCUMENTARY EVIDENCE will be used at the motion:

(a) Procedural Orders No. 1 and 3;

(b) The Issues List Decision;

(c) The Power Advisory Report and Board Staff's letter of August 31, 2010 enclosing the report for filing;

(d) OPG and intervenors interrogatories on the Power Advisory Report and the response thereto; and,

(e) Such further evidence as counsel may advise and the OEB may permit.

September 15, 2010

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27th Floor
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Tel: 416.481.1967
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AND TO: All Intervenors

ATTACHMENT 1

PROCEDURAL ORDER NO. 1

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.

PROCEDURAL ORDER NO. 1

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. The Board has assigned the application file number EB-2010-0008.

The Board issued a Notice of Application and Oral Hearing on June 4, 2010. The Board received 11 requests for intervenor status. The Board approves these intervention requests. The Board also received 2 requests for observer status and approves these requests. A list of the parties to the proceeding is attached as Appendix A.

The following parties have also applied for cost award eligibility: Association of Major Power Consumers in Ontario, Consumers Council of Canada, Canadian Manufacturers & Exporters, Energy Probe Research Foundation, Green Energy Coalition, Pollution Probe, School Energy Coalition, and Vulnerable Energy Consumers Coalition. The Board finds that each of these parties is eligible to apply for an award of costs under the Board's *Practice Direction on Cost Awards.*

A draft issues list is attached as Appendix B. An Issues Conference involving Board Staff, intervenors and OPG will be convened on **Tuesday, July 6, 2010.** The purpose of the Issues Conference is not to develop an agreed negotiated issues list. The objective of the Issues Conference is to review and discuss the draft issues list. Parties will also have the opportunity to provide input to Board staff. Based on the input received at the Issues Conference, Board staff will prepare a revised draft issues list that will be issued following the Issues Conference. Intervenors and OPG will have the opportunity to make written submissions on the revised draft issues list and propose changes for the Board's consideration. In proposing additional issues parties should provide justification and give consideration to whether the item is already included under one of the proposed issues. Similarly, parties proposing to remove or limit the scope of an issue on the draft list should provide justification. After reviewing these submissions, the Board will issue a final issues list. Only matters that are on the final issues list will be considered in this proceeding.

Confidential Filing

OPG has sought confidential treatment for certain tax information ("Tax Information") filed with the application in accordance with the Board's *Practice Direction on Confidential Filings* ("the Practice Direction").

In accordance with section 5.1.5 of the Practice Direction, OPG has filed a copy of the cover letter requesting confidential status which indentifies the documents that are being filed in confidence, together with a description of the basis on which confidentiality is claimed. As an interim measure, counsel and consultants for intervenors that wish to review the Tax Information may do so after signing a copy of the Board's Declaration and Undertaking (which can be found at Appendix D of the Practice Direction), and filing it with the Board. Parties that wish to make submissions on whether or not the Board should ultimately treat the Tax Information as confidential may make submissions on this issue in accordance with the steps described below. If the Board ultimately decides that the documents should not be afforded confidential treatment, OPG has requested that the Tax Information be withdrawn. The Board will issue a decision on the confidential status of the Tax Information after considering any submissions.

Redacted Material Filed

OPG has filed the following material in its application with certain sections redacted:

- 2010-2014 Business Plan; and

- Business Case Summaries.

However, the material ("Business Plan and Business Case Summaries") was not filed in accordance with section 5.1.5 of the Practice Direction. The Board notes that section 2.1.2 of the Filing Guidelines for OPG (EB-2009-0331) state that, "Unless otherwise directed by the Board, any request for confidential treatment of information by OPG must be made at the time of the filing and in accordance with the Board's *Practice Direction on Confidential Filings*." Further, and specifically with respect to the 2010-2014 Business Plan, section 2.2.3 of the Filing Guidelines for OPG state, "... if any claim for confidentiality is advanced with regard to any part of the Business Plan, a claim for confidentiality should be made in accordance with the Board's *Practice Direction on Confidential Filings*." The Board further is of the view that the unredacted Business Case Summaries should be filed.

OPG shall file the Business Plan and Business Case Summaries in unredacted form in accordance with the Practice Direction forthwith, so that the efficiency of the proceeding is not affected. The re-filing of the material will include the complete unredacted documents and a description of the basis on which confidentiality is claimed. As with the Tax Information noted above, counsel and consultants for intervenors will have the opportunity to submit a Declaration and Undertaking to review the unredacted versions of the documents. Parties that wish to make submissions on whether or not the Board should ultimately treat the redacted portions as confidential may make submissions on this issue in accordance with the steps described below.

The Board has provided a schedule for the proceeding below.

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. An Issues Conference, involving Board Staff, intervenors and OPG will be convened to review and discuss the draft issues list (attached at Appendix B). The Issues Conference will take place in the Board's hearing room at 2300 Yonge Street, 25th Floor, Toronto, commencing at 9:00 a.m. on **Tuesday, July 6, 2010**.

2. Following the Issues Conference, a revised draft issues list will be issued. OPG and intervenors may make submissions on the revised draft issues list and shall file any submissions with the Board and deliver them to all parties no later than **Tuesday, July 13, 2010.**

3. OPG may respond to the submissions of intervenors, and intervenors may respond to the submissions of OPG or other intervenors by filing those responses with the Board and delivering them to all parties no later than **Friday, July 16, 2010**.

4. Parties wishing to make submissions on the confidentiality status of the Tax Information and the Business Plan and Business Case Summaries shall file such submissions with the Board and deliver them to OPG and all other parties on or before **Tuesday, July 6, 2010**.

5. If OPG wishes to respond to any submissions on the confidentiality status of the Tax Information and the Business Plan and Business Case Summaries, it shall file such submissions with the Board and deliver them to the relevant intervenor and all other parties on or before **Tuesday, July 13, 2010**.

6. The schedule for the balance of the proceeding is summarized in the following table.

Procedural Step	Required Date
Board Staff Interrogatories Filed	Thursday, July 22, 2010
Intervenor Interrogatories Filed	Thursday, July 29, 2010
Interrogatory Responses Filed by OPG	Thursday, August 12, 2010
Technical Conference (Transcribed)	Thursday, August 19, 2010
Evidence Filed by Board Staff/Intervenors	Monday, August 23, 2010
Interrogatories Filed on Evidence of Board Staff/Intervenors	Monday, August 30, 2010
Interrogatory Responses Filed	Thursday, September 9, 2010
Settlement Conference	Commencing Tuesday, September 14, 2010
Oral Hearing	Commencing Monday, September 27, 2010

7. All conferences and hearings will take place in the Board's hearing rooms at 2300 Yonge Street, 25th Floor, Toronto, commencing at 9:00 a.m.

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. Please 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 you may email your document 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, June 29, 2010

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX B

ONTARIO POWER GENERATION INC.
2011-2012 PAYMENT AMOUNTS

EB-2010-0008

DRAFT
ISSUES LIST

Ontario Power Generation Inc.
2011-2012 Payment Amounts for
Prescribed Generating Facilities
EB-2010-0008

DRAFT ISSUES LIST

1. GENERAL

1.1 Has OPG responded appropriately to all relevant Board directions from previous proceedings?

1.2 Are OPG's economic and business planning assumptions for 2011-2012 appropriate?

2. RATE BASE

2.1 What is the appropriate amount for rate base?

2.2 Is OPG's proposal to include CWIP in rate base for the Darlington Refurbishment Project appropriate?

3. CAPITAL STRUCTURE AND COST OF CAPITAL

3.1 What is the appropriate capital structure and rate of return on equity?

3.2 Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

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?

4. CAPITAL PROJECTS

Regulated Hydroelectric

4.1 Do the costs associated with the regulated hydroelectric projects, and proposed for recovery, conform to and/or meet the requirements set out in O. Reg. 53/05? If not, were the additional costs prudent?

4.2 Are the proposed regulated hydroelectric capital expenditures and/or financial commitments appropriate and supported by business cases?

4.3 Are the proposed in-service additions for regulated hydroelectric projects appropriate?

Nuclear

4.4 Do the costs associated with the nuclear projects, and proposed for recovery, conform to and/or meet the requirements set out in O. Reg. 53/05? If not, were the additional costs prudent?

4.5 Are the proposed nuclear capital expenditures and/or financial commitments appropriate and supported by business cases?

4.6 Are the proposed in-service additions for nuclear projects appropriate?

4.7 Is the capitalization approach used for Pickering Units 2 and 3 appropriate?

4.8 Are the test period new nuclear expenditures, if any, appropriate?

4.9 Are the test period nuclear refurbishment expenditures appropriate?

5. PRODUCTION FORECASTS

Regulated Hydroelectric

5.1 Is the proposed regulated hydroelectric production forecast appropriate?

5.2 Is the estimate of surplus baseload generation appropriate? What economic and supply conditions are forecast to generate the surplus baseload generation outlook?

Nuclear

5.3 Is the proposed nuclear production forecast appropriate?

5.4 Are the estimates of forced loss rates for the individual nuclear plants reasonable?

6. OPERATING COSTS

Regulated Hydroelectric

6.1 Is the test period Operations, Maintenance and Administration budget for the regulated hydroelectric facilities appropriate?

6.2 Are the benchmarking results and targets for OPG's regulated hydroelectric facilities reasonable?

Nuclear

6.3 Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

6.4 Are the benchmarking results and targets for OPG's nuclear facilities reasonable?

6.5 Is the forecast of nuclear fuel costs appropriate?

6.6 Are the test period expenditures related to continued operations at Pickering B appropriate?

Corporate Costs

6.7 Are the 2011 and 2012 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

6.8 Are the "Centralized Support and Administrative Costs" and the allocation of the same to the regulated hydroelectric business and nuclear business appropriate?

6.9 Has OPG responded appropriately to the findings in the Human Resources and Finance Benchmarking Reports?

Other Costs

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

6.11 Are the asset service fee amounts charged to the regulated hydroelectric business and nuclear business appropriate?

7. OTHER REVENUES

Regulated Hydroelectric

7.1 Are the proposed test period regulated hydroelectric business revenues from ancillary services, segregated mode of operation and water transactions appropriate?

Nuclear

7.2 Are the proposed test period nuclear business non-energy revenues appropriate?

Bruce Nuclear Generating Station

7.3 Are the test period costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate?

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?
8.2 Is the revenue requirement amount for nuclear liabilities related to nuclear waste management and decommissioning costs appropriately determined?

9. DESIGN OF PAYMENT AMOUNTS

9.1 Has the hydroelectric incentive mechanism encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices?

10. DEFERRAL AND VARIANCE ACCOUNTS

10.1 Is the nature or type of costs recorded in the deferral and variance accounts appropriate?
10.2 Is the proposed inclusion of costs related to Pickering B continued operations in the Capacity Refurbishment Variance Account appropriate?
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?
10.6 Should the proposed variance account related to IESO non-energy charges be established?

11. REPORTING AND RECORD KEEPING REQUIREMENTS

11.1 What reporting and record keeping requirements should be established for OPG?

12. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

The Board Report, *A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.*, EB-2006-0064, November 30, 2006, stated that, "The Board will implement an incentive regulation formula when it is satisfied that the base payment provides a robust starting point for that formula."

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?

ATTACHMENT 2

DECISIONS AND ORDERS ON

CONFIDENTIAL FILINGS AND ISSUES LIST,

AND PROCEDURAL ORDER NO. 3

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

APPENDIX A

ONTARIO POWER GENERATION INC.
2011-2012 PAYMENT AMOUNTS

EB-2010-0008

FINAL ISSUES LIST

Ontario Power Generation Inc.
2011-2012 Payment Amounts for
Prescribed Generating Facilities
EB-2010-0008

FINAL ISSUES LIST

1. GENERAL

1.1 Has OPG responded appropriately to all relevant Board directions from previous proceedings?

1.2 Are OPG's economic and business planning assumptions for 2011-2012 an appropriate basis on which to set payment amounts?

1.3 Is the overall increase in 2011 and 2012 revenue requirement reasonable given the overall bill impact on consumers?

2. RATE BASE

2.1 What is the appropriate amount for rate base?

2.2 Is OPG's proposal to include CWIP in rate base for the Darlington Refurbishment Project appropriate?

3. CAPITAL STRUCTURE AND COST OF CAPITAL

3.1 What is the appropriate capital structure and rate of return on equity?

3.2 Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

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?

4. CAPITAL PROJECTS

Regulated Hydroelectric

4.1 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?

4.3 Are the proposed in-service additions for regulated hydroelectric projects appropriate?

Nuclear

4.4 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?

4.6 Are the proposed in-service additions for nuclear projects appropriate?

4.7 Is the proposed treatment for the Pickering Units 2 and 3 isolation project costs appropriate?

5. PRODUCTION FORECASTS

Regulated Hydroelectric

5.1 Is the proposed regulated hydroelectric production forecast appropriate?

Nuclear

5.2 Is the proposed nuclear production forecast appropriate?

6. OPERATING COSTS

Regulated Hydroelectric

6.1 Is the test period Operations, Maintenance and Administration budget for the regulated hydroelectric facilities appropriate?

6.2 Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's hydroelectric facilities reasonable?

Nuclear

6.3 Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

6.4 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?

6.6 Is the forecast of nuclear fuel costs appropriate?

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

Corporate Costs

6.8 Are the 2011 and 2012 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

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?

6.10 Is OPG responding appropriately to the findings in the Human Resources and Finance Benchmarking Reports?

Other Costs

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

6.12 Are the asset service fee amounts charged to the regulated hydroelectric business and nuclear business appropriate?

7. OTHER REVENUES

Regulated Hydroelectric

7.1 Are the proposed test period regulated hydroelectric business revenues from ancillary services, segregated mode of operation and water transactions appropriate?

Nuclear

7.2 Are the proposed test period nuclear business non-energy revenues appropriate?

Bruce Nuclear Generating Station

7.3 Are the test period costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate?

8. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

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?

8.2 Is the revenue requirement amount for nuclear liabilities related to nuclear waste management and decommissioning costs appropriately determined?

9. DESIGN OF PAYMENT AMOUNTS

9.1 Is the design of regulated hydroelectric and nuclear payment amounts appropriate?

9.2 Is the hydroelectric incentive mechanism appropriate?

10. DEFERRAL AND VARIANCE ACCOUNTS

10.1 Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

10.2 Are the balances for recovery in each of the deferral and variance accounts appropriate?

10.3 Is the disposition methodology appropriate?

10.4 Is the proposed continuation of deferral and variance accounts appropriate?

10.5 Should the proposed variance account related to IESO non-energy charges be established?

10.6 What other deferral and variance accounts, if any, should be established for the test period?

11. REPORTING AND RECORD KEEPING REQUIREMENTS

11.1 What reporting and record keeping requirements should be established for OPG?

12. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

The Board Report, *A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.*, EB-2006-0064, November 30, 2006, stated that, "The Board will implement an incentive regulation formula when it is satisfied that the base payment provides a robust starting point for that formula."

12.1 When would it be appropriate for the Board to establish incentive regulation, or other form of alternative rate regulation, for setting payment amounts?

12.2 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?

ATTACHMENT 3

THE POWER ADVISORY REPORT AND

BOARD STAFF'S LETTER OF AUGUST 31, 2010

Ontario Energy Board
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Ontario

BY E-MAIL

August 31, 2010

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: Ontario Power Generation Inc.
2011-2012 Payment Amounts for Prescribed Generation Facilities
Board File Number EB-2010-0008

Please find enclosed a report prepared by Power Advisory LLC, *Update to Report on Methodologies for Setting Ontario Power Generation Payment Amounts*. This report is filed in relation to issues 12.1 and 12.2 in this proceeding.

Board staff note that in the Decisions and Orders on Confidential Filings and Issues List and Procedural Order No. 3 issued on July 21, 2010, the Board stated that it "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." Accordingly, Board staff anticipates that the Power Advisory report will serve as a reference for the potential subsequent proceeding related to possible forms of alternative rate regulation for OPG. However, Board staff is filing the report in the current proceeding in the event any party wishes to refer to it within the context of issues 12.1 and 12.2, and will call the report's authors as witnesses if necessary.

Please forward the Power Advisory report to Ontario Power Generation Inc. and all other registered parties to this proceeding.

Yours truly,

Original Signed By

Violet Binette
Project Advisor, Applications & Regulatory Audit

Update to Report on Methodologies for Setting Ontario Power Generation Payment Amounts

Prepared for:

Ontario Energy Board

August 30, 2010

Power Advisory LLC

poweradvisoryllc.com
978 369-2465

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1. Introduction and Purpose

The Ontario Energy Board (OEB or Board) engaged Power Advisory LLC (Power Advisory) to update a report prepared by London Economics International LLC (London Economics) on methodologies for setting payment amounts for Ontario Power Generation Inc.'s (OPG's) prescribed generation assets.[1] These prescribed generation assets are its baseload hydroelectric facilities (the Sir Adam Beck, DeCew Falls and RH Saunders projects) and the Pickering and Darlington nuclear facilities. Specifically, the Board requested that Power Advisory update three sections of the London Economics Report:

- Section 2 which summarized the methodologies for setting payment amounts;
- Section 3 which provided case studies of other jurisdictions that employed these methodologies; and
- Section 6 which reviewed the implications of the methodologies for Ontario.

1.1 Contents of This Report

This report provides this update. This first chapter represents the introduction and summarizes the scope of Power Advisory's review. Chapter 2 reviews the regulatory framework that applies to OPG's prescribed assets including the regulations that provide the Board with the authority to set the rates for these assets. This chapter also provides an overview of the findings made by the Board in its 2008 decision under Board File No. EB-2007-0905, the initial decision that established payment amounts for these assets. Chapter 3 reviews the three different methodologies for setting payment amounts that were considered by the Board, citing examples of their applications in other jurisdictions. Chapter 4 reviews some of the considerations associated with implementing the Cost of Service (COS) and incentive ratemaking methodologies given Ontario policy objectives and OPG's prescribed generation assets.

[1] London Economics International LLC, *Alternatives for Regulation Prices Associated with Output from Designated Generation Assets*, May 19, 2006 (London Economics Report).

2. Regulation of OPG Prescribed Assets

2.1 Overview of OPG

OPG is a crown-owned generation company which owns and operates various generation assets in the Province of Ontario. These generation assets have a generation capacity of 21,729 MW (as of December 31, 2009) and include three nuclear generating stations; five fossil generating stations; 65 hydroelectric generating facilities and two wind turbines. In addition, OPG owns two nuclear generating facilities leased long-term to Bruce Power and is a part owner in several other generation assets in Ontario.

OPG is subject to the terms of a Memorandum of Agreement (MOA) with its shareholder, the Province, that sets out the Province's expectations regarding OPG's mandate, governance, performance, and communications. Key elements of the MOA include:

- OPG has a commercial mandate, and is to operate on a financially sustainable basis and maintain the value of its assets;
- OPG's key nuclear objective is to reduce the risk to the Province arising from its investment in nuclear generating stations; and
- OPG is to pursue continuous improvement in its nuclear generation operations and internal services.

2.2 Identification of OPG Prescribed Assets

The nine generating stations that are covered by the regulation (*Ontario Regulation 53/05 or O. Reg. 53/05)* which establishes the prescribed assets (collectively, the "prescribed assets") have a combined capacity of 9,020 MW, or about 45% of OPG's wholly owned and operated generation capacity. In 2009, these prescribed assets provided about 72% of OPG's total output and 48% of Ontario's total energy requirements.[2] These nine generating stations are listed in Table 1 below.

[2] The proportion of Ontario's energy production met by OPG's prescribed assets increased in 2009 as lower overall electricity demand reduced the required output from its fossil units .

Table 1: Ontario Power Generation's Prescribed Generation Assets

Nuclear Facilities	MW
Pickering A	1,030
Pickering B	2,064
Darlington	3,524
Total	6,618

Hydroelectric Facilities	MW
Sir Adam Beck 1	417
Sir Adam Beck 2	1,499
Sir Adam Beck Pump GS	174
DeCew Falls 1	23
DeCew Falls 2	144
RH Saunders	1,045
Total	3,302

Source: OPG Hydroelectric Business Overview, OPG Regulated Facilities Payment Amounts, March 29, 2010 and London Economics Report, p. 4.

2.3 Regulatory Framework for OPG's Prescribed Assets

Under *O. Reg. 53/05,* pursuant to the *Ontario Energy Board Act, 1998 (*the *Act)*, OPG receives regulated prices for electricity generated by most of its baseload hydroelectric facilities and all of the nuclear facilities that it operates.[3] Under *section 6(1) of O. Reg. 53/05*, the Board may establish the form, methodology, assumptions and calculations to be used in making an order that determines payment amounts for the purpose of section 78.1 of the *Act*. Prior to April 1, 2008, these prices were stipulated by regulation.

Although the Board was provided with considerable discretion as to the payment methodology, the regulation did include certain requirements. Specifically, *O. Reg. 53/05* constrains the scope of the Board's review of specific capital and operating costs as well as changes in output. The regulation establishes three variance and deferral accounts to capture certain costs after the effective date of the Board's initial rate order. These are: (1) a nuclear development variance account to capture differences between (a) actual non-capital costs incurred by OPG in the development of proposed new nuclear facilities, and (b) the amount of any such non-capital costs included in the payments set by the Board; (2) a Pickering A

[3]Section 78.1(1) of the *OEB Act* establishes the Board's authority to set the payment amounts for the prescribed generation facilities. Section 78.1(4) states: "The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment."

return to service deferral account for non-capital costs that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station; and (3) a nuclear liability deferral account to capture the revenue requirement impact of any change in OPG's nuclear liabilities resulting from new approved reference plans.

In addition to the requirements related to recovery of variance and deferral accounts, *O. Reg. 53/05* also directs the Board to ensure OPG recovers certain other costs: (1) costs to increase output from or to refurbish prescribed facilities; (2) costs and firm financial commitments for proposed new nuclear facilities; (3) the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan; and (4) costs it incurs with respect to the Bruce Nuclear Generating Stations which are leased to Bruce Power. , *O. Reg. 53/05* also directs the Board to ensure that revenues from Bruce Power which exceed costs are considered.

In March 2006, the Board initiated a consultation process to obtain the input of interested parties regarding the most appropriate regulatory methodology for setting payments for OPG's prescribed assets. To inform the consultation process Board staff engaged London Economics to review different methodologies for setting payments amounts for generation assets and to summarize its findings in a report that was published in May 2006. Board staff then issued a discussion paper (the "Staff Report") in July 2006 reviewing alternative methodologies for setting OPG payment amounts and recommending a preferred alternative.[4] The Staff Report evaluated three options: (1) cost of service regulation; (2) incentive regulation; and (3) regulatory contracts. These three alternatives had been identified and reviewed in some detail in the London Economics report. Board staff concluded that "that incentive regulation was the best choice of a long-term methodology having regard to the Board's mandate and its statutory objectives of protecting the interests of consumers, promoting economic efficiency in generation and facilitating the financial viability of the electricity industry... [and] that an incentive regulation methodology met the regulatory criteria of transparency, fairness, efficiency and consistency."[5]

2.4 Board Report on Methodology for Setting Payments

In November 2006 the Board issued a report outlining the regulatory methodology that it would employ for the upcoming review for setting payment amounts of OPG's prescribed generation assets.[6] In its Report the Board noted that establishing "the appropriate approach

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[4]Staff Discussion Paper, *Regulatory Options for Setting Payments for the Output from OPG's Prescribed Generation Assets*, July 6, 2006.

[5]EB-2006-0064, Board Report: A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc., November 30, 2006 (Board Report: Setting Payment Amounts for Prescribed Generation Assets), p. 7.

[6]Board Report: Setting Payment Amounts for Prescribed Generation Assets, p. 7.

to setting just and reasonable payments for the prescribed generation assets is driven by the substantive objectives of the Board, as well as the Board's responsibility to provide an effective, fair and transparent process."[7] The Board also noted that its review and determinations would be driven by "two objectives in the *Ontario Energy Board Act, 1998* with respect to electricity ...:

- to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electric service; and,
- to promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry."[8]

Finally, the Board noted that it:

> "also has the objective of achieving efficient and cost effective outcomes. Efficiency can be defined in a number of ways. The Board's key focus in this regard is to encourage productivity gains that are enduring and for the benefit of both the regulated company and the consumer. This means that regulated companies have incentives to manage costs while maintaining or improving their service levels. This objective is less about balancing than about identifying incentives that provide both consumer benefits and opportunities for the regulated company."[9]

The Board accepted "staff's recommendation that in the longer term, the method for setting payments should be based on an incentive regulation regime."[10] However, the Board noted that "a full incentive regulation regime is in this case better implemented once the parameters of the incentive regulation formula (i.e., base payments, productivity and cost inflation factors) have been determined by a review of OPG's financial and cost data."[11]

The Board indicated that it will:

(1) "undertake a series of limited issues cost of service processes to set the base payment.

[7]Board Report: Setting Payment Amounts for Prescribed Generation Assets, p. 4.

[8]Board Report: Setting Payment Amounts for Prescribed Generation Assets, p. 4. The Act was subsequently amended by the *Green Energy and Green Economy Act, 2009* which added three additional objects: (1) to promote conservation; (2) facilitate development of the smart grid; and (3) promote the use and generation of electricity from renewable energy resources.

[9]Board Report: Setting Payment Amounts for Prescribed Generation Assets, p. 4.

[10]Board Report: Setting Payment Amounts for Prescribed Generation Assets, p. 1.

[11]Board Report: Setting Payment Amounts for Prescribed Generation Assets, p. 1.

(2) extend the limited cost of service process over several payment orders until all relevant issues have been examined.

(3) implement an incentive regulation formula when it is satisfied that the base payment provides a robust starting point for that formula."[12]

2.5 Initial Decision on Setting Payment Amounts

The Board issued its initial decision on setting payment amounts in November 2008 (EB-2007-0905) and established new prices retroactively to April 1, 2008 using a forecasted cost of service methodology. Specifically, these regulated payment amounts were based on a projected revenue requirement reflecting forecasts of generation output, total operating costs and a return on rate base.

The Board applied the following Cost of Service formula to calculate distinct rates for hydroelectricity and nuclear production:

Rates = Revenue Requirement ÷ Production, where:

Revenue Requirement =

	Operations, Maintenance & Administrative Costs (OM&A)
+	Fuel (Nuclear)
+	Gross Revenue Charge (Hydro)
+	Depreciation & Amortization
+	Property & Capital Taxes
+	Cost of Capital
-	Other Revenues
-	Mitigation

Expenses were based on a forecast test period consisting of the 21 months from April 1, 2008 through December 31, 2009 and reflected forecasts of rate base, expenses and production. The COS and rates for hydroelectric and nuclear production are presented in Table 2 and show the relative magnitude of cost of service elements for both the hydroelectric and nuclear prescribed assets.

As shown in this table, hydroelectric and nuclear rate bases are similar in size but OM&A costs are many times higher for nuclear facilities. A large portion of the hydroelectric revenue requirement is represented by gross revenue charge.

[12]Board Report: Setting Payment Amounts for Prescribed Generation Assets, p. 7.

Table 2: Revenue Requirements and Rates for OPG's Prescribed Assets
EB-2007-0905 Revenue Requirements
($ Millions)

	Hydroelectric			Nuclear		
	9 Mos. 2008	2009	21 Months	9 Mos. 2008	2009	21 Months
Rate Base	3,880.2	3,869.9		3,509.1	3,483.8	
Cost of Capital	208.3	278.2	486.5	175.9	234.3	410.2
Expenses						
OM&A	93.1	119.0	212.1	1,646.8	2,147.3	3,794.1
Fuel	0.0	0.0	0.0	125.7	204.2	329.9
GRC	179.9	244.1	424.0	0.0	0.0	0.0
Dep. & Amort.	52.8	70.9	123.7	296.8	415.3	712.1
Other Taxes	6.5	8.7	15.2	16.3	22.0	38.3
Total	332.3	442.7	775.0	2,085.6	2,788.8	4,874.4
Revenues						
Bruce	0.0	0.0	0.0	(80.0)	(111.9)	(191.9)
Other	(34.4)	(46.6)	(81.0)	(49.4)	(50.9)	(100.3)
Total	(34.4)	(46.6)	(81.0)	(129.4)	(162.8)	(292.2)
Income Taxes	0.0	0.0	0.0	0.0	0.0	0.0
Rev Requirement	506.2	674.3	1,180.5	2,132.1	2,860.3	4,992.4
Mitigation	(11.6)	(15.4)	(27.0)	(60.7)	(81.0)	(141.7)
Net Rev. Req.	494.6	658.9	1,153.5	2,071.4	2,779.3	4,850.7
Deferral & Variance Account Recovery			0			(176.2)
Revenue Req. Through Payments			1,153.5			4,674.5
Forecast Production (TWh)			31.5			88.2
Price ($/MWh)			36.62			53.00

The Board also implemented the variance and deferral accounts called for in *O. Reg. 53/05, Payments Under Section 78.1 of the Act*. In addition, the Board also authorized establishment of a variance account to reflect the volatility in nuclear fuel costs.
Finally, the Board approved a hydroelectric production incentive mechanism that was proposed by OPG. Under this mechanism, OPG receives the regulated rate for average forecasted hourly production reflected in the design of rates and either sells or purchases power at the IESO hourly market clearing price for production that is greater than or less than this forecasted amount. As stated by OPG, this mechanism provides an incentive for OPG to increase its hydro production to serve as a peaking resource that improves system reliability

and helps temper market price increases during periods of high demand.[13]

[13] See discussion and findings in EB-2007-0905 Decision with Reasons, pages 50-55.

3. Overview of Methodologies for Setting Payment Amounts

This section reviews three principal methods for establishing payments for regulated utility assets: (1) cost-of-service, (2) incentive regulation, and (3) regulation by contract. As noted above, the Board applied a COS methodology in establishing payment amounts in EB-2007-0905, while also expressing a desire to implement an incentive approach at a future time. As discussed below, all three forms of regulation rely on establishing the cost of providing service as a starting point or benchmark. Each of the three approaches provides incentives that influence capital and operating decisions with key distinctions among them. Thus, each has potential implications for achieving the Board's goals to promote efficiency while continuing to maintain or improve service levels.

3.1 Cost-of-Service Regulation

3.1.1 The Basic Cost-of-Service Rate Model

Cost-of-service (COS) is the cornerstone of price regulation for regulated utility services and is widely applied throughout the electricity and natural gas industries, particularly in the monopoly transmission and distribution segments of these industries. Many generation assets also continue to be subject to COS regulation in markets that have not been restructured.

The COS pricing model is straightforward: utilities are allowed an opportunity to recover their prudently incurred costs of providing service plus a reasonable opportunity to earn a return on rate base that reflects the utility's risk. For purposes of calculating rates, this is referred to as the revenue requirement and is based on the value of rate base at a specified date, and costs incurred over a specified period, usually referred to as the "test period". Regulatory agencies take varying approaches to the test period which generally fall into two categories: an historical period, with adjustments for known and measurable changes (e.g., a labor cost increase that has already been agreed to), or a forward-looking or future period that corresponds to the period that rates will be in effect. A forward-looking period is more likely to be representative of costs for the period that rates will be in effect (and therefore more likely from the utility's perspective to provide a reasonable opportunity to earn its authorized return) but requires a review of cost and demand projections.

As described in section 2.5, the Board adopted a forward-looking test year in the initial payments decision. Thus, the rate calculation depended on forecasts of production and costs for the hydroelectric and nuclear facilities. This production forecast is less critical for hydroelectricity as the Board established a variance account that recognizes the difficulty of projecting water conditions. Variance accounts are common elements of COS regulation and are discussed in the following subsection. However, the forecast of nuclear production is critical due to the one-part energy rate that was adopted by the Board.[14] One consequence of a one-part energy payment is that the recovery of fixed costs, including the return on capital, is entirely dependent on the level of production, creating the potential for returns that are either lower or higher than the amount relied on to calculate prices. However, such a rate structure provides a strong incentive to maximize output so as to increase revenues.

3.1.2 Variations to the Basic Cost-of-Service Pricing Model

This basic cost-of-service model is often tailored to reflect particular circumstances of the utility and developments in the utility industry, and to achieve evolving regulatory objectives. Variations to the COS pricing model most often relate to the timing of cost recovery and the allocation of risk between customers and utility shareholders. As a result, they can have an impact on utility earnings and influence investor perceptions of the financial standing of utilities operating within a regulatory jurisdiction. The timing of cost recovery relative to when costs are incurred is commonly referred to as "regulatory lag".

Once established, regulated rates typically remain in place: (1) for a period established by regulators or settling parties; or (2) until the utility requests a change in rates to address an earnings shortfall.[15] In the COS model, rate calculations are based on test period costs and sales. As the test period becomes dated, the utility's realized return on equity may be higher or lower than the authorized return as revenues and costs deviate from those relied upon to establish rates. Therefore, the ability to operate without a new rate case as long as earnings are sufficient can provide incentives for efficiency improvements as utilities strive to increase returns during this period, with the strength of the incentive determined in part by the length of the "stay-out".

These deviations may be attributable to factors that are either within or beyond the control of the utility. Regulators seek to provide incentives for utilities to control costs that are within their control. They may also allow utilities to track and recover costs that are clearly outside of their control. The approach to regulation will determine whether utilities absorb these costs between rate cases or whether they are either passed on to customers or deferred for recovery over a future period.

As an example of factors within their control, a utility may implement programs to achieve cost savings such as a reduction in staffing levels. Assuming that the program results in a net

[14] In EB-2007-0905, OPG had requested recovery of 25% costs associated with its nuclear facilities through a fixed charge. The Board decided that OPG should continue to recover 100% of nuclear costs through a variable payment, citing reduced OPG risk and higher average costs that would result if the facilities produced less than the forecasted amount of power that is reflected in rates.

[15] In EB-2010-0008, OPG has requested that new prices take effect March 1, 2011.

cost reduction, utility earnings would be higher at least until such time as new rates take effect. In the subsequent rate case, the cost-of-service will be reduced to reflect lower staffing levels and customers will begin realizing these benefits in the form of lower rates. Regulators utilize a variety of tools to allocate the costs, revenues, and risks between utility shareholders and customers between rate cases. These include:

1. Variance Accounts: allow utilities to recover actual costs incurred for specified expenses that are variable and/or difficult to project (e.g., volatile fuel costs) or subject to legislative or regulatory changes (e.g., a change in an applicable tax rate). In most jurisdictions where generation investment is subject to regulation, the cost of fuel will be separately determined from other costs and updated on a predetermined frequency (often every six months) to reflect changes in natural gas and other fuels whose prices are volatile and difficult to forecast.

2. Revenue Crediting Mechanisms: provide for the return of revenues generated from services that are supported by assets paid for by customers. A representative level of credits may be included in the rate calculation with any excess amounts refunded to customers. In some cases, the utility is provided with an incentive to pursue revenue generating opportunities using assets that are being paid for by customers. For example, profits from off-system sales of electricity from generation that is not needed to meet the needs of on-system customers may be shared, with the utility retaining a relatively modest portion (e.g., 5 to 10%) as an incentive to pursue these market opportunities.

3. Deferral Accounts: allow utilities to track expenses that were not or could not have been anticipated when rates were established and recover them over some future period. Regulators may approve a request for deferral accounting if expenses are deemed to be extraordinary and non-recurring. The costs of restoring power after an extraordinary ice storm or hurricane may be subject to deferral treatment until the costs are reviewed in the next rate case.

4. Investment Recovery Mechanisms: allow utilities to begin recovering the COS associated with large capital investments through a price adder (or "rider") without having to file a rate case. Investment recovery mechanisms have become increasingly prevalent over the past few years. Focusing on the regulated generation sector, these mechanisms allow utilities to recover the COS associated with the acquisition or development of a new resource or the extraordinary investments in existing facilities, particularly in response to regulatory or legislative policy directives. They address regulatory lag and provide for an increase in rates without filing a full rate case. For example, wind projects are capital intensive and may be required to meet renewable

procurement targets. Recovery of investments in pollution control equipment on existing coal-fired generation may also be subject to rate adders. Infrastructure trackers are increasingly common in the natural gas distribution industry to address safety and reliability concerns associated with the need to replace cast iron and steel mains.

5. Construction Work in Progress (CWIP): allows utilities to recover the financing costs associated with a major capital investment during the construction period. CWIP has been most commonly applied during lengthy nuclear plant construction projects.

6. Revenue Decoupling[16]: is a recent variation intended to remove any disincentive that distribution utilities may have to encourage energy efficiency by severing the link between sales and revenues (and thereby earnings). In general, once rates are established in a rate case based on the cost of service, they are adjusted each year to reflect actual sales. For example, if sales were to decrease relative to the amount used to calculate rates, they would be adjusted upward to compensate the utility for the decrease in sales. Decoupling is thought to be particularly important to remove any disincentive to reduce sales where a considerable portion of fixed costs are recovered through variable rates.

As noted in section 2.5, two of these mechanisms, variance accounts and deferral accounts, are part of the current approach to regulation of OPG's prescribed assets.

3.1.3 Incentives Under a Cost-of-Service Pricing Model

Even the most basic COS model provides incentives to utilities to operate efficiently or increase sales between rate cases because changes in revenues or costs that are not explicitly accounted for in the ratemaking process are borne by, or benefit, shareholders between rate cases. Thus, shareholders typically bear the risk (and reap the benefits) associated with sales that are lower or higher than normal due to weather or economic conditions. This is certainly true for OPG's nuclear production as its profits are driven by increases in production above the levels that are reflected in the design of rates. In contrast, this incentive would be removed if sales and revenues were decoupled.

Cost efficiency incentives are strongest if the decision to file a rate case is at the discretion of the utility and certain other conditions apply. These conditions are cost reductions that do not affect output or service quality and improved production from existing facilities. Under

[16] Revenue Decoupling is included as a variation to a COS model but might also be implemented as a form of revenue cap IRM model.

these circumstances, the utility may retain the benefits for many years and will be more willing to undertake investments required to realize efficiencies.

One criticism of the COS model is that it provides a disproportionate incentive to take actions that result in an increase in utility rate base when other options may be available. For example, utilities may prefer to acquire or own a generation resource which provides an opportunity to earn a return on rate base as opposed to obtaining power supply through an agreement to purchase the output of an asset owned by a third party.[17] This is not likely to be an issue in Ontario given the market structure and OPG's role in this market.

In summary, litigated rate case decisions involve numerous investment and expense activities that, considered as a whole, provide incentives that drive utility behavior. One common practice in the United States is negotiated multi-year settlements between the utility and other parties.[18] One benefit of such settlements is that they may incorporate incentives that provide potential benefits to both customers and shareholders that might otherwise not be possible through a rate order.

The current methodology for establishing payment amounts incorporates some of these incentives. OPG will realize the benefits of efficiency measures for up to three years, or until such time as the cost of service is refreshed in EB-2010-0008. OPG has an incentive to shape the output of its designated hydroelectric facilities so as to maximize production when it is most valuable. It has an incentive to increase the availability and output of its nuclear facilities as a result of the energy-only rate design. OPG also has had an incentive to maximize revenues from certain ancillary services as it will retain all revenues above those reflected in the calculation of rates.

3.2 Incentive Regulatory Mechanisms

Incentive regulatory mechanisms (IRMs) take many forms but can be divided into two general categories: (1) broad-based IRMs, and (2) targeted IRMs. These two approaches can be combined within the same regulatory scheme and may include performance metrics that are designed to ensure that service quality and reliability is not adversely affected by incentives designed to realize cost efficiencies.[19] As discussed in section 3.1.2, they each

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[17] The potential treatment of such power purchases as imputed debt by rating agencies is increasingly an issue in regulatory reviews of resource additions.

[18] A review of the 47 electric rate cases filed in the United States in 2009 indicates that 31 cases (66%) involved settlements that were approved by the respective utility regulatory commission. For example, New York utilities typically negotiate three-year rate settlements with intervener parties after filing a rate case.

[19] Service quality and reliability plans for electric distribution utilities include measures of the quality of interactions with the utility through the call center, bill accuracy, and reliability as measured by the number and

provide incentives for efficiency improvements in the form of cost reductions or increases in output and as a consequence offer sustained customer benefits that may last beyond the IRM period by providing an opportunity for enhanced utility financial performance.

3.2.1 Broad-Based IRMs

Broad-based IRMs focus on the performance of regulated activities as a whole, rather than on a select subset of activities. Price-cap regulation is an example of a broad-based IRM as the utility has considerable flexibility to operate within the price cap, pursuing efficiencies and retaining the benefits of these activities. Earnings-sharing mechanisms are another example of a broad-based IRM as regulators focus their attention on earnings rather than specific revenue or expense activities that result in earnings.

3.2.1.1 Price Cap Regimes

Price cap regulation typically takes the following form:

$$\text{Price}_t = \text{Price}_{t-1} \times (1 + \text{Inflation}_t - \text{Productivity Offset}) + Z$$

Prices are usually adjusted on an annual basis using a published inflation index that is deemed to be appropriate given the nature of the costs of providing the service. The productivity offset is established at the beginning of the price cap program based on a study that assesses the productivity improvements available in the industry or firm.

Price cap models also generally include the ability to adjust prices to reflect specified types of expenditures (or "exogenous" or "Z" factors) that are beyond the control of the utility and have a material impact on the utility's financial performance. Expenditures required to respond to government-mandated programs that could not have been anticipated when the price cap model was adopted are an example of a Z-factor. A change in regulation is an example that is commonly included in price cap models. Some price cap models also include "off-ramps" which provide the ability to terminate the plan if circumstances change significantly such that the financial strength of the firm is threatened.

Although price cap regimes are usually applied to monopoly delivery functions, there is no reason why they could not be applied to hydroelectric and nuclear generation facilities, tailored to the specific circumstances of OPG's prescribed assets. A price cap will provide an incentive to OPG to manage its nuclear OM&A expenses more aggressively, with the

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duration of service interruptions. They may also include measures of worker safety. Service quality and reliability plan frequently incorporate financial penalties and rewards based on performance relative to benchmarks for each measure.

incentive increasing with the duration of the term of the price cap. It may also be appropriate to adopt service quality and reliability benchmarks with penalties and rewards to ensure that facilities are available to provide electricity.[20] The price cap could also be calculated based on the cost of service before any "other revenues" are credited if these other revenues reflect sales into a market (e.g., ancillary services) where both the quantity sold and price are difficult to project. These sales could be subject to revenue sharing between shareholders and customers if the regulator wanted to add a targeted incentive for this purpose.

3.2.1.2 Earnings-Sharing Mechanisms

Earnings-sharing mechanisms are not themselves a method of setting price but are often an important component of an IRM. They require the measurement of actual earnings, most often on an annual basis. If earnings exceed the authorized return on equity, a portion of the earnings above this benchmark is returned to customers as a credit during the following year. If earnings fall short, customers will bear a portion of the shortfall in the subsequent year through a per-unit surcharge or refund. As the level of sales during the recovery or refund year is uncertain, these rate mechanisms usually include reconciling mechanisms.

Earnings sharing mechanisms can be seen as a hybrid of COS and IRM regulation. Earnings-sharing mechanisms are typically symmetrical, i.e., the relative portions of earnings shared between customers and shareholders are the same whether there is a surplus or shortfall. The mechanisms frequently include a "deadband" around the authorized ROE in which no sharing takes place and within which shareholders absorb any earnings shortfall or retain any earnings above the authorized ROE.

Earnings-sharing mechanisms are often included as part of multi-year rate settlements where the parties want to avoid an agreement that is overly beneficial to one party or the other as the result of events that cannot be predicted at the time of the agreement. While an earnings-sharing mechanism cannot be used to establish payment amounts for the prescribed assets it could be used as an element of a comprehensive ratemaking approach.

Earnings sharing mechanisms do not necessarily lead to more efficient operations, particularly compared to a COS model in which the utility retains 100% of the benefit of increased efficiencies and absorbs 100% of earnings shortfalls. They are typically more burdensome from a regulatory perspective, compared to a price cap IRM, and also lessen incentives to seek efficiencies beyond the target since incremental earnings will be shared between shareholders and ratepayers. Rather, earnings sharing mechanisms are attractive as

[20] Safety regulation is the purview of the Canadian Nuclear Safety Commission (CNSC). Investments and operating expenses that are mandated by the CNSC would likely need to be considered in a variance account or specifically considered in any IRM framework.

a "belt and suspenders" to regulators or consumer representatives negotiating a rate settlement that are concerned about the public acceptance of high utility earnings that might otherwise result.

3.2.1.3 Implementation of Broad-Based IRMs
Broad-based mechanisms are usually implemented after prices have been established based on a COS review. The utility is required to make a filing to support a change in prices based on application of the incentive formula. The filing may itself be the subject of litigation as parties and the regulatory agency will verify the underlying data and application of the formula. Any issue with respect to the allocation of benefits or costs among rate classifications should be addressed in the tariffs that are adopted when the mechanisms are approved.

3.2.2 Targeted IRMs

Targeted IRMs draw a boundary around a set of regulated activities and measure performance relative to these activities.

There are several examples of targeted incentives applied to the power supply function. These include availability incentives for low marginal cost resource options and heat rate incentives for fossil-fuel power plants. For example, Public Service Company of Colorado had an incentive tied to the output of its coal-fired plants. As noted in section 3.1.2 above, incentives to maximize the value of the portfolio through off-system sales are also common.

Targeted IRMs may present some unique challenges. If costs and/or revenues must be allocated (rather than directly assigned) between activities subject to the IRM and other activities, this creates a potential for disputes similar to those that arise when allocating costs and revenues between regulated and unregulated activities. To the extent that there is controversy, these disputes may require litigation before the regulatory agency to resolve.

Targeted IRMs may not be appropriate where there are opportunities for trade-offs between investments and operating expenses in performing an activity. Thus, a targeted incentive tied only to OM&A costs for OPG's nuclear assets may not be appropriate. A targeted incentive that favors one or the other will distort decision-making and may result in higher costs in the long run. A broader measure, such as a price cap, takes both capital and operating costs into account and would be more appropriate under these circumstances.

It may be appropriate to adopt a targeted incentive that promotes availability of OPG's nuclear facilities combined with a measure that ensures that the assets continue to be properly maintained and that safety is not sacrificed.

3.3 Regulation by Contract

An alternative methodology for pricing generation that has been employed in several jurisdictions in Canada is regulation by contract, where the rates for the prescribed assets would be specified by contract. Regulation by contract is an option that has the flexibility to incorporate elements of both COS and IRM regulation and can be viewed as a variant of IRM regulation, but with fewer options for resetting rates. One of its primary benefits is the potential to achieve beneficial outcomes that are difficult, if not impossible, to achieve through litigation of a rate proceeding. It can be accomplished entirely outside of a rate proceeding as with certain of the Canadian examples provided below, or as the outcome of settlement discussions after a rate filing has been made. As noted above, approximately two-thirds of the rate cases filed in 2009 in the United States were resolved through multi-year settlement agreements which can be viewed as a form of regulation by contract.

The rates received by the generation facilities would be specified by the contract based on escalators, price indices, availability provisions and other performance standards (e.g., heat rates for thermal units), and contract capacities. The form of pricing provision depends in large part on the type of generation facility to which they apply. For dispatchable generation technologies such as natural gas-fired generation assets, a two-part contract structure is often used with capacity and energy payments. The capacity payment is typically based on the rated capacity, with the charge expressed in terms of $/kW-year and covering all fixed costs including a return on capital and fixed operating and maintenance costs. To ensure that the facility is available to operate when needed the capacity payment is subject to availability provisions, with capacity payments reduced as availability declines. The energy payment is based on variable costs and expressed in terms of dollars per MWh generated or as the product of a heat rate (e.g., Btu/kWh) and fuel cost ($/MMBtu) as measured by a price index.[21]

With OPG's designated assets being baseload generation resources, which typically operate whenever available, an energy payment ($/MWh) has been used. Under such a contract structure, compensation may be required when the units are available to operate, but are unable to given system technical constraints such as Surplus Baseload Generation or transmission constraints. One consequence of a one-part energy payment is that the recovery of fixed costs, including the return on capital, is entirely dependent on the level of production, creating the potential for returns that are either significantly lower or higher than the revenue requirement upon which prices were calculated.

[21] This framework was used for the Reliability Must Run contracts negotiated by OPG and the Independent Electricity System Operator for the Lennox Thermal Generating Station.

Regulation by contract would require a counterparty to OPG to negotiate the terms of the contract. The Ontario Power Authority (OPA) is an obvious counterparty. The OPA has negotiated contracts with OPG for the refurbishment and development of new hydroelectric facilities.[22] However, such an approach is clearly contrary to the direction provided by *O. Reg. 53/05.*

3.3.1 Board Staff Assessment

Board staff noted "that the regulatory contract model can, depending on how it is implemented, provide interested parties with the least amount of disclosure regarding OPG's cost information and may provide less of an opportunity for involvement by interested parties."[23] Therefore, regulation by contract may not be sufficiently transparent or open and as a result provide for sufficiently detailed examination of OPG's financial and cost accounts to identify cost efficiencies that will allow payments to be lower than they otherwise might be.[24] Furthermore, Board staff was concerned with the regulatory efficiency of such an approach since they would require a parallel or sequential contract negotiation and Board review processes given that the Board cannot cede its payment-setting responsibility to the negotiating parties.[25]

As discussed, the Board accepted staff's recommendation that the regulatory contract model not be employed. Therefore, this alternative is reviewed in less detail than the other two alternatives.

3.3.2 Examples of Regulation by Contract

Both Québec and British Columbia rely on "Heritage Contracts" to provide the domestic customers of the Crown-owned utilities in these jurisdictions with guaranteed access to low-cost hydroelectric power. As hydroelectric generation assets, the costs of these generation assets is highly stable with the major uncertainty being the annual energy output available from these facilities. These two heritage contract structures were reviewed in the London Economics Report. There have not been substantive changes to these contracts since this report was issued, other than in BC which expanded the scope of the heritage assets.

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[22] See the Hydroelectric Energy Supply Agreement between OPG and the OPA for the output of the Lac Seul and Ear Falls generating stations.

[23] Staff Discussion Paper, *Regulatory Options for Setting Payments for the Output from OPG's Prescribed Generation Assets*, (July 6, 2006) p. 16.

[24] Board Report: Setting Payment Amounts for Prescribed Generation Assets, p. 7.

[25] Staff Discussion Paper, *Regulatory Options for Setting Payments for the Output from OPG's Prescribed Generation Assets*, (July 6, 2006) p. 16.

There are major differences between the two contract structures. BC implemented a "revenue requirements" model where rates are based on the underlying cost of service. This approach recognizes the significant year-to-year variability in power supply costs in BC based on water availability. Québec on the other hand implemented a "fixed price, fixed quantity approach" where the heritage pool price is stipulated for a fixed quantity of power and recognizes the significant storage capability of Hydro-Québec's reservoirs which better allows it to manage annual variations in water run-off.

3.3.2.1 British Columbia

BC Hydro owns and operates the vast majority of generation in British Columbia. BC Hydro's hydroelectric facilities provide about 78% of the Province's energy requirements, the Burrard Thermal Generating Station about 7.5%, and purchases from Independent Power Producers and generators in adjacent markets provide about 14.5%.

BC Hydro's assets are subject to the terms of the *BC Hydro Public Power Legacy and Heritage Contract Act*. This Act ensures public ownership of BC Hydro's heritage resources, which includes BC Hydro's transmission and distribution systems, and all of BC Hydro's existing generation and storage assets, and enabled the establishment of the heritage contract.

The heritage contract ensures that the electricity generated by the heritage resources continues to be available to BC Hydro ratepayers based on cost of service, not market prices. BC Hydro's rates under the heritage contract are reviewed and approved by the BCUC. While a COS approach is currently used to set these rates, the BCUC has the authority to implement incentive regulation to establish the appropriate payment amounts. The revenue requirements model which establishes the heritage contract rate shields BC Hydro from variations in water availability and requires BC Hydro customers to bear this risk through higher rates to cover the additional cost of replacement energy. The heritage payment obligation includes the cost of energy (primarily for fossil resources required to supplement the output of hydroelectric resources), operating costs, asset related expenses, generation related transmission asset costs, and return on equity. These costs are offset by revenues from existing power supply obligations to third parties, ancillary service revenues and a portion of trade revenues. The term of the heritage contract is for at least ten years, with the Government able to terminate the contract with five years notice after 2009.

The major changes to BC's heritage contract structure stem from the *Clean Energy Act,* which was introduced in April 2010 and expanded the scope of BC Hydro's heritage assets.[26] The *Clean Energy Act* specifically identified as heritage assets the Waneta dam and generating facility; Site C a proposed 900 MW hydroelectric project; Mica Dam expansion,

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[26]The *Clean Energy Act* also integrated BC Transmission Corporation back into BC Hydro.

units 5 and 6, 500 MW each; Revelstoke Dam expansion, units 5 and 6, 500 MW each; and the Northwest Transmission Line which will provide access to a portion of the 2,000 MW of green energy that is estimated to be available in Northwestern BC.

The incentives for increased cost and operational efficiencies in the BC heritage contract structure are similar to those that exist in cost-of-service ratemaking frameworks in general, except the revenue requirements model approach appears to dull the incentives for efficient operation of the system under the revenue requirements model employed.

3.3.2.2 Québec

In 2001 the Québec electricity market was restructured by the vertical separation of Hydro-Québec. The *Act to amend the Act respecting the Régie de l'énergie* established a heritage pool giving Québec consumers access to a maximum volume of 165 TWh (plus associated losses) of electricity per year from Hydro-Québec Production at a rate of 2.79 cents/kWh. The four primary Hydro-Québec divisions that resulted were: (1) Hydro-Québec Production which under a heritage contract is obligated to provide 165 TWh plus associated losses to Hydro-Québec Distribution at 2.79 cents/kWh; (2) Hydro-Québec Distribution which procures and supplies electricity above the 165 TWh provided by Hydro-Québec Production competitively through tenders; (3) Hydro-Québec TransEnergie (in place since 1997) which administers the province's open access transmission service; and (4) Hydro-Québec Équipement and Societed'energie de la Baie James, which design, build and refurbish generation and transmission facilities, primarily for HQ Production and HQ TransÉnergie.

HQ Production owns and operates 36,810 MW of generation capacity of which 34,499 MW (94%) is hydroelectric, 1,634 MW is fossil (4%), 675 MW is nuclear (2%) and 2 MW is wind.[27] In addition, HQ Production has long-term power purchase agreements that provide it with access to 7,302 MW including 5,428 MW from the Churchill Falls project in Labrador, 1,297 MW with independent power producers, and 657 MW with privately owned wind farms.

The heritage contract between HQ Production and HQ Distribution is a fixed price, fixed quantity contract. The 2.79 cents/kWH rate covers all costs of owning and operating the facilities required to provide the 165 TWh delivered to HQ Distribution. In 2010, HQ Production's available energy output is forecast to be 199.3 TWh (about 22 TWh greater than the 177.6 TWh required to satisfy its heritage contract obligations) and it is forecast to have a total energy in storage at its reservoirs of 112.4 TWh (as of January 1, 2010).[28]

[27]Hydro-Québec 2009 Annual Report, p. 114.

[28]Hydro-Québec, Strategic Plan 2009-2013, p. 18.

As a fixed price, fixed quantity obligation, the Hydro-Québec heritage contract provides greater incentives than the BC heritage contract to reduce costs, increase output and optimize the timing of the output since Hydro-Québec Production is able to capture all savings that it realizes. However, any efficiencies realized aren't shared with Québec consumers. This is a major issue with regulation by contract where there is a fixed or contract-specified price. It can provide significant incentives for generators to pursue efficiency improvements, however, the benefits from these improvements typically are not shared with customers for the term of the contract.

3.4 The Role of Benchmarking

Benchmarking can play an important role in all three methodologies. As recognized by the Board, benchmarking of costs and performance against other facilities serves an important role, particularly for nuclear operations. Benchmarking can be used in several ways:

- Cost benchmarking as an indicator of the reasonableness of the level of costs or the rate of change in costs;
- Cost benchmarking to indicate areas that require improvement;
- Cost benchmarking as an input to a price formula;
- Performance benchmarking to indicate areas for improvement; and
- Performance benchmarking to establish penalties and rewards.

Benchmarking is particularly useful as an indicator that costs and or performance are out-of-line with industry standards or practices. The effort to determine the reasons for deviations from industry norms will often lead to changes that improve efficiency and performance. The nuclear industry has historically relied extensively on benchmarking analyses, with a particular focus on comparisons to plants that use similar designs.

However, the extension of benchmarking to create financial rewards and penalties is more controversial. The primary concerns relate to the selection of a comparable group, whether the group is truly comparable, and how to reflect any unique circumstances of the regulated utility when applying a benchmark.

3.5 US Case Studies on the Application of COS and IRM

This section highlights generation related rate recovery approaches in states that have not yet restructured and in which the power supply remains a regulated function. Most of these states are located in the Midwestern and Southeastern areas of the United States where restructuring was either halted after the California energy crisis or was not undertaken to begin with. As noted in the London Economics report, utility rate cases address generation along with other utility functions and it is not always possible to separate out the generation impacts from the overall regulatory approach. For example, for states that have approved earnings sharing mechanisms as part of multi-year rate case settlements, the earnings subject to the mechanism are for the enterprise as a whole. The following paragraphs highlight regulatory approaches that may be informative for regulation of OPG's prescribed assets. These summaries are organized by state.

Colorado: For Public Service Company of Colorado (PSCo), a subsidiary of Xcel Energy, fuel costs are subject to an incentive mechanism that allows sharing above and below a benchmark price formula. Electric utilities have incentives to generate margins from short-term energy sales. Past investments to improve air quality were recovered through a rate rider until they could be reflected in base rates in a subsequent rate case. Certain renewable energy costs are also subject to recovery through a tariff rider. They are also allowed to earn a premium return on eligible renewable energy investments needed to meet renewable portfolio targets. Most recently, on August 13, 2010, PSCo filed an emissions reduction plan that seeks approval of a rate mechanism to recover $1.3 billion of capital costs to comply with the Colorado's "Clean Air Clean Jobs Act" through a combination of retiring, repowering, and adding new emissions control equipment to its coal fleet. More specifically, PSCo is seeking approval of an "Emissions Reduction Adjustment" tariff designed to recover the return on CWIP on emissions reductions investments as well as the amortization of incremental costs associated with early retirements or conversions of specified coal-fired generation. PSCo proposes to roll recovery of these costs into base rates from time to time whenever it files a base rate case.[29]

Georgia: Georgia has recently approved multi-year rate case settlements that include incentive provisions. The Commission has recently approved CWIP recovery for two new proposed 1,102 MW nuclear power plants. The state's largest utility, Georgia Power, is allowed to recover environmental compliance costs that are ordered by a regulatory authority through a special tariff, subject to a cap. Costs in excess of the cap are subject to deferral accounting unless Georgia Power is under-earning. These provisions are part of a complex earnings-sharing mechanism included in its rate settlement. The settlement includes a three-year stay-out agreement, again subject to certain provisions.

Indiana: Indiana's utilities have alternative regulation plans in place. The plans include earnings sharing mechanisms and several variance accounting provisions to recover fuel and other costs. However, the recovery of fuel costs is subject to an earnings test specified by state statute. Utilities are also permitted to share in margins earned from off-system sales above a benchmark level. Sales of emissions allowances are also subject to a sharing mechanism. Variance accounting is used for certain Midwest ISO related expenses. Utilities are allowed to earn a return on CWIP for qualified environmental compliance investments

[29] PSCo's filing is available at www.xcelenergy.com/Colorado/Company/About_Energy_and_Rates/Pages/Clean-Air-Clean-Jobs-Plan.aspx

and these investments are recoverable through a tariff rider. In at least one case, the Commission approved accelerated depreciation recovery for environmental compliance investments. They are also allowed to earn a return on certain demand-side management ("DSM") programs.

Wisconsin: Legislation provided the Commission with the ability to establish a separate rate of return for new generating facilities, including other financial parameters to remain in place over the life of the plant as part of a pre-approval process. The Commission has also approved a return on 50% of CWIP. Wisconsin's utilities have divested their ownership interests in nuclear plants. The Commission establishes benchmarks for electric fuel costs, with sharing above and below the benchmark between shareholders and customers. Recovery of electric fuel costs is subject to variance accounting although utilities can request deferral of the recovery or refund.

4. Implementation Considerations for COS and IRM Methodologies

The Board, after completion of a comprehensive consultative process, has determined that it is appropriate to adopt an IRM approach at a future date once it deems that the base payments – or starting point - for an incentive formula are appropriate. The Board has indicated its intention to refine the COS model before adopting an IRM approach.[30] Given this direction the appropriate strategy at this time is to incorporate new elements into the current COS model that achieve the Board's objective of promoting productivity gains.

Therefore, in this Chapter, Power Advisory provides an assessment of the various methodologies for establishing payment amounts for the prescribed assets and discusses actions that the Board could take to set the stage for implementation of a more comprehensive IRM approach in the future. This approach is consistent with Power Advisory's view that there are many variations within each of the alternative methodologies that individually, and in combination, provide incentives for increased operating efficiencies for OPG's prescribed assets. The approach taken, and elements adopted, should reflect the distinct circumstances and objectives with regard to OPG's prescribed hydroelectric and nuclear assets.

Ultimately, these alternatives should be evaluated in light of the Board's goals, including the objective of setting payment amounts to promote "efficient and cost effective outcomes." Power Advisory recognizes that the methodology must comply with the existing requirements of *O.Reg. 53/05.*

4.1 General Assessment of Alternative Methodologies for Setting Payments

As with any regulatory scheme, the details establish the relative merits of the application of the three methodologies that have been discussed. Outlined below are some general observations regarding these methodologies.

First, the distinctions among these alternatives are not as stark as they might appear. Each has its foundation in cost-of-service principles, a benchmark that the IRM and regulation by contract approaches use as a starting point, and under IRM, likely return to when rates are reset at the end of the program or agreement.[31]

Second, utility incentives under IRM and regulation by contract should be compared to incentives that are present under even the most basic cost-of-service model. The length of

[30]Board Report: Setting Payment Amounts for Prescribed Generation Assets, p. 7.

[31] Under a fixed price, fixed quantity approach for contract by regulation rates are set for the duration of the contract and the form of payment setting methodology at the end of the contract term isn't necessarily specified.

time between resetting of payments is a key determinant of efficiency incentives under each of the models.

Third, the models each require a vigorous review of costs in setting initial rates. However, they may differ with respect to the extent of oversight once rates have been determined. Under the cost-of-service approach, regulators can maintain a more active role between rate cases by implementing variations to the basic COS model including specifying variance and deferral accounts and monitoring service quality. The form of oversight, although not necessarily the level of effort, will differ under IRM approaches as the regulator must still administer the IRM framework. The regulator can implement reporting requirements under both COS and IRM approaches in order to monitor aspects that are of most concern, including service quality. The specification of reporting requirements will define the regulatory burden to both the applicant and the regulator. The degree of ongoing oversight under regulation by contract depends on its terms. For example, in the model employed by BC the contract is based on a revenue requirements model that is administered by the regulator, whereas in Québec with a fixed price and fixed quantity, there is little role for the regulator. Regulation by contract may also incorporate ongoing reporting requirements.

Fourth, financial performance of the utility depends primarily on how these approaches are implemented. In COS regulation this is a critical issue, with one of the objectives of the ratemaking process providing an opportunity for a reasonable return. Therefore, COS regulation is likely to provide the greatest earnings certainty to OPG, particularly if the application of the COS model includes elements such as variance accounts and investment trackers. In IRM and regulation by contract there is the potential for greater variability in the financial performance depending on the design and implementation of the framework, leading to results that are unacceptable to regulators. Some IRM frameworks include off-ramps that effectively terminate the IRM and allow the utility to revert to COS regulation, but only under extraordinary circumstances.

Fifth, and finally, with respect to regulation by contract, the regulatory agency can exert considerable influence even if it is not a party to the negotiations. It can do so by providing clear policy guidance to the negotiating parties as to the standards that will be applied when it conducts its regulatory review of any agreement that is reached. However, the agency may not have the benefit of discussions or information that has led to the agreement. On the other hand, the parties may have the ability to negotiate terms that allocate risks more precisely than is always possible in rate case litigation.

4.2 Consideration of OPG's Hydroelectric and Nuclear Assets

The choice of methodology that is applied throughout the transition to an IRM approach should reflect the particular circumstances in Ontario including policy objectives (i.e., achieving efficient and cost effective outcomes) and the cost and operating characteristics of the assets that are being regulated.[32] As a result, it may cause the Board to adopt differing regulatory approaches for OPG's hydroelectric and nuclear assets.

4.2.1 OPG's Hydroelectric Assets

OPG's hydroelectric assets have relatively low operating costs (particularly as compared to its nuclear facilities) although it is still important to provide incentives for OPG to operate them efficiently. As indicated in Table 3, OPG's prescribed hydroelectric facilities had operations, maintenance and administration (OM&A) costs of $3.17/MWh in 2009. A variance of 10% in this OM&A amount represents approximately $0.30/MWh. While the Board should promote efficiency gains wherever possible, it appears that cost improvements available from OPG's prescribed hydroelectric assets would be more modest than are available from its nuclear operations. It is also important that these assets be well maintained and capital additions be made when required so that they can continue to serve as a source of low-cost power for years to come.[33] Finally, a critical issue is the merits of providing sufficient incentives for OPG to produce hydroelectricity from its prescribed assets during times when it provides the greatest value to Ontario. The hydroelectric production incentive approved by the Board in EB-2007-0905 provided such an incentive, although the Board also indicated its intention to review the mechanism in the current OPG proceeding. In summary, for hydroelectric facilities, the incentives should aim to control costs without sacrificing future production and to optimize output so that production is offered at the time that it is the most valuable (or, if possible, both).

Table 3: Review of Historical and Actual Expenses and Output for OPG Designated Assets

Designated Hydro	2007	2008	2009	2010	2011	2012
OMA ($M)	78.5	53.9	61.5	61.8	68.7	62.2
Output (TWh)	18.2	19.0	19.4	19.3	19.4	19.0
OMA ($/MWh)	$ 4.31	$ 2.84	$ 3.17	$ 3.20	$ 3.54	$ 3.27
Nuclear						
OMA ($M)	1,532	1,585	1,615	1,616	1,543	1,555
Output (TWh)	44.2	48.2	46.8	46.2	48.9	50.0
OMA ($/MWh)	$ 34.66	$ 32.88	$ 34.51	$ 34.98	$ 31.55	$ 31.10

Source: OPG Regulated Facilities Payment Amounts, Nuclear OMA, Production & Fuel and Regulated Hydroelectric Operations Stakeholder Meeting #1, March 29, 2010.

[32]Board Report: Setting Payment Amounts for Prescribed Generation Assets, p. 4.

[33]Power Advisory notes that there is an account to recover the costs to increase output and refurbish these facilities. This should avoid any potential adverse impacts on output over the long term as result of incentives to reduce costs.

4.2.2 OPG's Nuclear Assets

In contrast, providing an incentive to control OM&A costs appears to be much more important for OPG's nuclear assets. As indicated by Table 3, the OM&A expenses for the three nuclear generating stations are twenty times those of the designated hydroelectric assets.

There are two predominant effects of the methodology for setting payment amounts for nuclear in terms of promoting efficient and cost effective outcomes: it can provide incentives for OPG to control costs or it can result in incentives to increase output (or, if possible, both). OPG submitted a benchmarking study as part of its recent filing in response to a Board directive in its 2008 Payments Amount decision.[34] This study provides insights regarding the areas where efficiency incentives should focus. Table 4 below summarizes the results for two areas and supports the assertion that primary areas of focus for efficiency improvements would be with respect to reductions in OM&A costs and increasing the output of these units.[35] The performance of each of the Pickering plants is well below the median on both cost and output, while Darlington's output matches the top quartile but its operating costs are above the median.

Table 4: OPG Nuclear Generation Benchmarking Results

Performance Indicator	Best Quartile	Median	Pickering A	Pickering B	Darlington
2-Year Unit Capability Factor (%)	91.0	84.3	56.6	73.2	92.0
3-Year Non-Fuel Operating Costs ($/Net MWh)	18.1	21.3	82.6	51.0	25.1

Source: ScottMadden, OPG Nuclear 2009 Benchmarking Report
Red indicates bottom quartile performance
Green indicates top quartile performance
Yellow indicates third quartile performance

Power Advisory believes that the energy-only payment approach currently employed provides strong incentives for OPG to maximize its output. As a baseload generation asset with little ability to shape its output profile other than through the scheduling of maintenance outages, there is less need to provide incentives to maximize output during higher price periods.[36] However, it is important that OPG's nuclear assets be available to produce electricity during these periods.

[34] ScottMadden, OPG Nuclear 2009 Benchmarking Report.

[35] These benchmarking results don't account for differences in OM&A costs that may be attributable to the specific requirements of CANDU nuclear technology.

[36] OPG does have to determine when to schedule maintenance outages in coordination with the IESO. With no consideration given to the value of output, OPG could be incented to focus exclusively on reducing the duration

In summary, Power Advisory believes that an incentive mechanism for nuclear assets should focus on reductions in OM&A costs and increases in unit availability.

4.3 Implications for the Design of an Appropriate Methodology

In its November 2006 Report, the Board noted that it "will implement an incentive regulation formula when it is satisfied that the base payment provides a robust starting point for that formula."[37] In EB-2007-0905, the Board focused on several aspects of OPG's cost of service including the capital structure and return on equity, rate base, and OM&A expenses. In the current proceeding, EB-2010-0008, the Board will focus on many of these same issues as it examines the appropriateness of using the same capital structure and return on equity for both hydroelectric and nuclear facilities, additions to OPG's rate base, and OM&A costs with due consideration to benchmarking analyses. Therefore, the Board and other parties will likely have a better understanding of OPG's cost of service after this proceeding is completed.

There are a number of considerations as to whether a base payment amount represents a "robust starting point" for an IRM framework. First and foremost, the regulator must be convinced that it adequately understands the cost for the regulated assets as well as opportunities for productivity improvements and that the IRM framework appropriately reflects these factors. To this end, one possible indication would be to evaluate how the base payment would change from year-to-year after the effects of the various variance and deferral accounts are accounted for. A retrospective analysis could be used to evaluate how the forecast base payment amount derived by employing the IRM framework compares to the actual base payment amount after the effects of the variance and deferral accounts are considered. To the degree that there aren't significant sustained differences between the forecast and actual base payment amounts, then the regulator can be reasonably confident that its formula adequately tracks cost drivers or key performance indicators.

A second consideration is whether the IRM formula and the base payment amount would provide adequate incentives for cost reductions, productivity gains, and output increases given the underlying performance of the utility assets. Benchmarking can provide valuable insights regarding the potential for such performance improvements. Specifying the parameters in the IRM formula to induce these performance improvements requires judgment, informed by analysis. This analysis should be based on additional benchmarking

of outages without regard to ensuring that these outages are scheduled during periods when prices are anticipated to be lowest.

[37]Board Report, 11.

studies that build on the most recent studies or productivity studies that provide a preliminary estimate of the "X-factor" for nuclear facilities. As indicated by

Table 3, the operating costs of the facilities can vary appreciably from year-to-year. While the variance and deferral accounts should reduce some of this variation, these accounts also were established in large part to shield OPG from adverse financial effects stemming from the factors that were beyond their control. Continuation of at least some of these accounts is likely to be appropriate, as discussed further below.

4.3.1 Methodology for Setting Payment Amounts for OPG's Hydroelectric Assets

As discussed, the most significant issue with respect to the performance of OPG's prescribed hydroelectric assets is to incent production during times when it is of the greatest value, recognizing that these are effectively baseload hydroelectric assets (other than the Beck Pump Generating Station). The design issues for a COS or IRM approach are likely to be less critical than specifying appropriate variance and deferral accounts. Therefore, the payment methodology should focus on controlling OM&A costs, optimizing the value of production, and ensuing that there are no disincentives to long term maintenance and required capital additions.

4.3.2 Methodology for Setting Payment Amounts for OPG's Nuclear Assets

The benchmarking data suggest that the incentives for OM&A cost reductions and production increases from the design of the methodology for setting payment amounts for OPG's nuclear assets are more important than for its prescribed hydroelectric assets.[38] OPG's nuclear OM&A costs relative to the overall payment level and in comparison to other nuclear facilities suggests that a price cap approach may provide OPG with strong incentives to reduce these costs. The inflation factor under such a price cap regime would presumably be based on the underlying cost elements for the different asset classes. For example, the proportion of labour costs in the OM&A could be linked to the consumer price index, with other cost components linked to other appropriate inflation indices. Price cap regulation will also provide OPG with an incentive to improve capacity factors. Nuclear industry capacity factors have increased over the past two decades due in part to deregulation and improved asset management practices as firms had a strong financial incentive to increase production. An IRM plan can provide similar incentives to OPG. The Board could also continue to reflect rate mitigation in establishing the base payment to incent OM&A cost reductions.

[38] Power Advisory hasn't performed a detailed review of this benchmarking data and wasn't asked to offer an opinion on the need for OM&A cost reductions or production increases at OPG's nuclear generating facilities. As such, this comments on the costs and performance of these units should be viewed is a high level observations based on the summary data provided in Table 4.

Establishment of the productivity or X-factor in the price cap formula should be informed by benchmarking analyses. The X-factor represents opportunities for improvements in efficiency for the industry as a whole, as well as utility-specific opportunities for improvements in efficiency that are based on how efficient it may be relative to other utilities. Firms that are deemed to be less efficient than the average, as informed by benchmarking analyses, would have greater opportunities for efficiency improvements and the price cap formula would incorporate a productivity offset that is higher than the industry average. Therefore, the determination of the X-factor will involve an assessment of efficiency improvements that may be available across the industry as well as the specific circumstances faced by OPG. Given the prospect that the Board will adopt an IRM framework in the future, OPG should have an obligation to continue to benchmark the costs and operations of its facilities against other nuclear assets. Although CANDU technology differs from other nuclear technologies, benchmarking analysis continues to provide valuable insights that can influence management decisions and regulatory oversight, even in advance of adoption of an IRM.

Given the importance of safety and reliability for nuclear operations, implementation of a broad-based IRM should provide specific consideration of these variables. The current pricing mechanism includes variance and deferral accounts to recover investments that are required to develop new nuclear facilities and address decommissioning and other capital and expense requirements. There may be future safety-related or other mandated costs as well. Thus, the Board should consider continuing these accounts to reflect costs that would not be incorporated into the base payment calculation. The Board may also want to consider investment tracking accounts to provide recovery of new investments that it has reviewed and approved during the term of the price cap. These costs can be rolled into the base payment at the end of the term. The qualifying investments must be clearly defined in advance and recovery should remain subject to a prudence review. For example, in order to seek recovery through an investment tracking account, OPG would need to demonstrate that the investments were required in order to satisfy a specific mandate issued by the Canadian Nuclear Safety Commission and of a magnitude such that they would be deemed to be "extraordinary" and qualify for such treatment. As such extraordinary would need to be defined. As a point of reference, at 50 TWh per year an increase in costs of $5 million represents $.10/MWh.

The regulations already allow OPG to recover investments designed to increase output. If OPG is paid on an energy basis then there is less need to segment such investments from the IRM unless it is clear that the OPG nuclear payment amount is below the value of energy produced. Otherwise OPG should make decisions as to whether to pursue such investments based on whether their costs are less than the payment amount. However, it may possible to design a stronger incentive for OPG's nuclear assets to be available during periods of high prices through a rate design or targeted IRM approach.

ATTACHMENT 4

BOARD STAFF INTERROGATORY RESPONSES

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Ontario

BY E-MAIL

September 14, 2010

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: Ontario Power Generation Inc.
2011-2012 Payment Amounts for Prescribed Generation Facilities
Board File Number EB-2010-0008

In accordance with Procedural Order No. 4, please find enclosed responses to interrogatories filed by the Association of Major Power Consumers in Ontario, Ontario Power Generation Inc. and the Power Workers' Union related to evidence filed by Board staff. Please provide a copy of these responses to Ontario Power Generation Inc. and all other registered parties to this proceeding.

Yours truly,

Original signed by

Violet Binette
Project Advisor, Applications & Regulatory Audit

Board Staff Response to AMPCO Interrogatory #1

Ref: Update to Report on Methodologies for Setting Ontario Power Generation Payment Amounts, August 30, 2010, Power Advisory LLC.

Interrogatory
Please provide the cost to the Board to engage Power Advisory to prepare this report.

Response
The cost to the Board to engage Power Advisory to prepare this report was $28,200.

Board Staff Response to AMPCO Interrogatory #2

Ref: Update to Report on Methodologies for Setting Ontario Power Generation Payment Amounts, August 30, 2010, Power Advisory LLC.

Interrogatory

a) Please provide Power Advisory's opinion as to the appropriateness of OPG's methodology for measuring the effectiveness of the hydro-electric incentive mechanism ordered by the Board in its Decision with Reasons in the EB-2007-0905 proceeding.

b) How should OPG's response to hydro-electric incentives be best monitored?

Response

a) Such a review is well beyond the scope of Power Advisory's agreement with the Board, and Power Advisory has not reviewed OPG's methodology for measuring the effectiveness of the hydro-electric incentive mechanism ordered by the Board in its Decision with Reasons in the EB-2007-0905 proceeding.

b) Such analysis is well beyond the scope of Power Advisory's agreement with the Board, and Power Advisory has not considered this issue.

Board Staff Response to AMPCO Interrogatory #3

Ref: Update to Report on Methodologies for Setting Ontario Power Generation Payment Amounts, August 30, 2010, Power Advisory LLC.

Interrogatory

In the proceeding EB-2007-0905, AMPCO filed evidence (Exhibit M Tab 2), that discussed in some detail previous performance incentive schemes applied to OPG, particularly the Market Power Mitigation Agreement (MPMA) and Regulation 53/05. AMPCO's evidence discussed the results of these measures.

Please provide Power Advisory's view of overall effectiveness and lessons learned from these previous incentive regimes applied to OPG.

Response

Power Advisory briefly reviewed AMPCO's filed evidence in EB-2007-0905. However, this review didn't provide a sufficient basis for assessing the overall effectiveness of these "performance schemes" and Power Advisory was not retained to perform an assessment of lessons learned from previous incentive regimes.

Board Staff Response to AMPCO Interrogatory #4

Ref: Update to Report on Methodologies for Setting Ontario Power Generation Payment Amounts, August 30, 2010, Power Advisory LLC.

Interrogatory

Please comment on whether and how the Board might encourage OPG to schedule nuclear production to as closely as possible match the production pattern to the demand pattern.

Response

Although this matter is not within the scope of the Power Advisory update of the London Economics May 2006 report, Power Advisory provides the following response.

Power Advisory does not recommend that the Board encourage OPG to schedule nuclear production to closely match the production pattern to the demand pattern. The costs of nuclear facilities are largely fixed. Therefore, nuclear units should be incented to operate whenever available and to increase their overall availability. However, the Board may wish to incent OPG to schedule its outages during periods when demand is lowest. Such outages must be scheduled in coordination with the IESO. Therefore, the effectiveness of any incentives may be limited by IESO criteria and objectives that it uses to coordinate outage schedules.

Board Staff Response to AMPCO Interrogatory #5

Ref: Update to Report on Methodologies for Setting Ontario Power Generation Payment Amounts, August 30, 2010, Power Advisory LLC.

Interrogatory

Regarding Table 4 on page 27, please comment on why Power Advisory relied upon non-fuel operating costs as a benchmark for comparing OPG performance with that of international peers instead of the combined fuel and non-fuel operating cost measure recommended by ScottMadden, OPG Nuclear 2009 Benchmarking report.

Response

Power Advisory was not directed to review the ScottMadden report before selecting the operating cost metric to be presented in the report. Power Advisory believed that the 3-Year Non-Fuel Operating Costs per MWh was a comprehensive and representative measure of the controllable operating costs for nuclear units, particularly given that CANDU units do not require enriched uranium and as a result generally have lower fuel costs than other nuclear technologies.

Board Staff Response to AMPCO Interrogatory #6

Ref: Update to Report on Methodologies for Setting Ontario Power Generation Payment Amounts, August 30, 2010, Power Advisory LLC.

Interrogatory

On page 29, the Power Advisory report indicates "Nuclear industry capacity factors have increased over the past two decades due in part to deregulation and improved asset management practices as firms had a strong financial incentive to increase production."

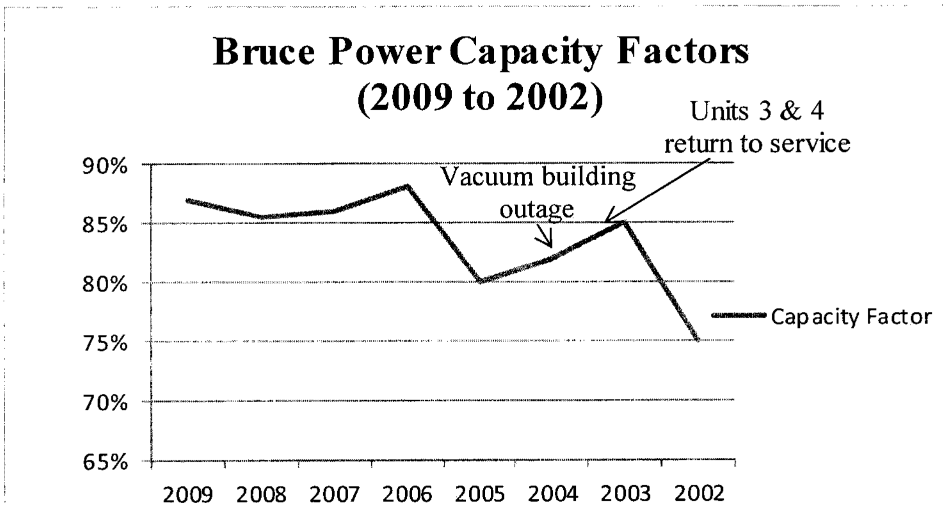
a) Please identify the jurisdiction or jurisdictions whose experience is noted in this statement.

b) Please indicate whether any Candu operations show indications of improving capacity factors over time.

Response

a) This excerpt refers to the experience in the United States as nuclear power plant capacity factors have increased from approximately 66% in 1990 to approximately 90% today as cited in the following webpage: http://www.world-nuclear.org/info/inf01.html

b) Bruce Power appears to have improved the capacity factors of the CANDU units that it operates as shown by the graph below and the overall capacity factors for all Bruce Power units shown in the table below. However, such an analysis is complicated by a number of factors that would affect the output of these units. For example, there was a vacuum building outage in 2004 at Bruce B for about one month that required the shutdown of these four units. In addition, Bruce Power returned to service Unit 4 in October 2003 and Unit 3 in January 2004 from a layup of the units. Returning these older units to service is likely to reduce Bruce Power's overall capacity factors, absent offsetting performance improvements. Finally, the data presented for 2009 is the availability factor which is likely to be a more appropriate performance measure for 2009 given the amount of time when there was Surplus Baseload Generation (SBG) in Ontario. During some of these periods of SBG Bruce Power was requested to reduce the output of its units. Power Advisory didn't have ready access to availability factors for this full period (1992 to 2009).Therefore, it is difficult to draw definitive conclusions from these data based on the high level analysis we have performed.



	2009	2008	2007	2006	2005	2004	2003	2002
Capacity Factor	87%	86%	86%	88%	80%	82%	85%	75%

Source: Bruce Power Annual Reports and TransCanada Corporation, 2009 Annual Report (which presents availability factor)

Board Staff Response to OPG Interrogatory #1

Ref: Update to Report on Methodologies for Setting Ontario Power Generation Payment Amounts. August 30, 2010. Power Advisory LLC.

Pursuant to its reasons set out in the Procedural Order No. 3, the Board eliminated certain proposed issues and restricted the issues to: (1) when it would be appropriate to establish incentive regulation, or other form of alternative rate regulation, for setting payment amounts (issue 12.1); and (2) 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 (issue 12.2)?

Interrogatory

Set out a list, by reference to page and paragraph, of those parts of the Power Advisory Report that are in response to Issue 12.1 and Issue 12.2 described above.

Response

The Power Advisory report updates the London Economics report (May 19, 2006) and as such, issues 12.1 and 12.2 are not its prime focus. Staff felt that it would serve as a useful resource to frame the issues and to present a range of options that might be considered in a future proceeding. A discussion of "next steps" could to some extent be informed by an understanding of the range of possible endpoints.

Those parts of the Power Advisory Report that are in response to issue 12.1 include:

- Page 28, paragraph starting with sentence, "In its November 2006 Report ..."
- Page 28, paragraph starting with sentence, "There are a number of considerations ..."
- Page 28, paragraph starting with sentence, "A second consideration is ..."

Those parts of the Power Advisory Report that are in response to issue 12.2 include:

- Page 24, Section 4
- Page 24-25, Section 4.1 in general

Board Staff Response to OPG Interrogatory #2

Ref: Update to Report on Methodologies for Setting Ontario Power Generation Payment Amounts. August 30, 2010. Power Advisory LLC.

Pursuant to its reasons set out in the Procedural Order No. 3, the Board eliminated certain proposed issues and restricted the issues to: (1) when it would be appropriate to establish incentive regulation, or other form of alternative rate regulation, for setting payment amounts (issue 12.1); and (2) 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 (issue 12.2)?

Interrogatory

Based on the Power Advisory Report, or upon other evidence filed in this proceeding, what are the OEB staff's detailed answers with respect to each of issues 12.1 and 12.2? Please provide specific references to all of the evidence on which OEB staff relies upon in support of its answers.

Response

This question essentially asks Board staff to provide its final argument with respect to issues 12.1 and 12.2. Presumably like all parties, Board staff will consider its position on these issues (and indeed on all issues) once the evidentiary portion of the proceeding is complete. To the extent that Board staff has concrete recommendations with respect to issues 12.1 and 12.2, these will be presented with final argument.

Board Staff Response to PWU Interrogatory #1

Issue 12.2
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?

Ref (a): August 30, 2010. Update to Report on Methodologies for Setting Ontario Power Generation Payment Amounts. Prepared for Ontario Energy Board. Power Advisory LLC.

Interrogatory
The above report makes reference to EB-2006-0064, Board Report: A regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc., November 30, 2006 [Board Report: Setting Payment Amounts for Prescribed Generation Assets]. On page 7, paragraph 5 of that report, the Board states:

> Although an incentive regulation methodology was the central recommendation, staff acknowledged that a number of proceedings would be required to determine some of the components of a complete incentive regulation formulation. In particular, Board staff recommended that the Board commission studies to determine cost inflation and productivity factors and investigate the need for "Z" factors and "off ramps" to account for unforeseen circumstances. Board staff acknowledged that these studies would also have to consider the appropriate methodologies to examine OPG's data and the availability of credible information and comparators to establish these factors.

The report filed by Board staff in this proceeding, referenced above, does not comment on the issue of 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.

Please describe the process that Board staff believes should be adopted to establish the framework for incentive regulation, or other form of alternative rate regulation, for OPG that would take into account the above excerpt from the Board Report: Setting Payment Amounts for Prescribed Generation Assets.

Response
Please see the response to OPG interrogatory #2 at ExhM/Tab1.15/Sch2.