ONTARIOPOWER GENERATION

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March 22, 2013

VIA EMAIL, COURIER AND RESS

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON
M4P 1E4

Dear Ms. Walli:

Re: EB-2012-0002 – Correction to Settlement Agreement

Attached is an updated version of the Settlement Agreement filed March 14, 2013. I am providing two (2) paper copies. OPG submitted the document on the Regulatory Electronic Submission System ("RESS") today.

The only change from the orginal version is a change to the note in line 8 of Attachment 1, Table 23A, where references to other line numbers were incorrect. There is no change to the substance of the table or anything else in the document.

Sincerely,

[Original signed by]

Colin Anderson

Attach

cc: Charles Keizer (Torys)
Carlton D. Mathias
EB-2012-0002 Intervenors

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March 14, 2013

VIA COURIER AND RESS

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

Dear Ms. Walli:

EB-2012-0002
Submission of Settlement Agreement

Pursuant to the Ontario Energy Board's ("OEB's") Procedural Order #6, please find attached a Settlement Agreement for the Panel's review and consideration. The Parties have worked diligently to achieve a comprehensive settlement on all issues.

As set out in the OEB's Procedural Order #1, I am providing two (2) hardcopies and one electronic copy in searchable PDF format filed through the OEB's web portal (RESS).

Best Regards,

[Original signed by]

Colin Anderson

Encl.

c. Carlton Mathias, OPG (email)
Charles Keizer, Torys LLP (email)
Violet Binette, OEB (email)
EB-2012-0002 Intervenors (email)

SETTLEMENT AGREEMENT

Ontario Power Generation Inc.

Application Regarding Deferral and Variance Accounts

for OPG's Regulated Hydroelectric & Nuclear Facilities

EB-2012-0002

March 14, 2013

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Ontario Power Generation Inc.
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SETTLEMENT AGREEMENT

A. PREAMBLE

This Settlement Agreement is filed with the Ontario Energy Board (the "Board" or "OEB") in connection with the application by Ontario Power Generation Inc. ("OPG") for an order or orders approving the disposition of certain deferral and variance account balances as at December 31, 2012, and the adoption of the Generally Accepted Accounting Principles of the United States ("USGAAP") for regulatory accounting purposes ("the Application").

Pursuant to the Board's Procedural Order No. 1 dated November 6, 2012, a Settlement Conference began on February 11, 2013, with further discussions on February 12, 13, 19, 20 and 21, 2013, in accordance with the *Ontario Energy Board Rules of Practice and Procedure* (the "Rules") and the Board's *Settlement Conference Guidelines* (the "Guidelines").

The Parties

OPG and the following intervenors (the "Intervenors" and, collectively with OPG, the "Parties"), being all of the parties in the proceeding, participated in the Settlement Conference in respect of all issues in the proceeding:

- Association of Major Power Consumers in Ontario ("AMPCO")
- Canadian Manufacturers & Exporters ("CME")
- Consumers Council of Canada ("CCC")
- Energy Probe Research Foundation ("Energy Probe")
- Power Workers' Union ("PWU")
- School Energy Coalition ("SEC")
- Vulnerable Energy Consumers Coalition ("VECC")

Ontario Energy Board staff also participated in the Settlement Conference, but in accordance with the Guidelines is neither a Party nor a signatory to this Settlement Agreement. Although Board Staff is not a Party to this Settlement Agreement, the Board Staff who did participate in the Settlement Conference are bound by the same confidentiality provisions that apply to the Parties to the proceeding.

Confidentiality

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Guidelines. The Parties understand this to mean that the documents and other information provided, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement, or not, of each issue during the Settlement Conference are strictly confidential and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, other than as may be necessary to resolve a subsequent dispute over the interpretation of any provision of this Settlement Agreement.

Parameters of the Proposed Settlement

Without prejudice to the positions of the Parties with respect to the issues that might otherwise be considered in this proceeding should a hearing be required, the Parties have organized this Settlement Agreement in a manner that is consistent with the Final Issues List as set out in Appendix ‘A’ of Procedural Order No. 2, which sets out seven distinct issues. An additional section has been added to address other aspects of the settlement that do not fit neatly into one of the issues in the Final Issues List.

The Parties have reached a comprehensive agreement on all issues.

The Settlement Agreement describes the agreements reached on the settled issues and identifies the Parties who agree or who take no position on each issue. A party who is noted as taking no position on an issue may or may not have participated in the discussion on that particular issue and takes no position on the settlement reached or on the sufficiency of the evidence filed to date.

For each issue, the Settlement Agreement provides a direct reference to the supporting evidence on the record to date. The Parties agree this Agreement and the Appendices also form part of the record in EB-2012-0002. The Appendices were prepared by the Applicant. The Intervenors are relying on the accuracy and completeness of the Appendices in entering into this Agreement.

The Parties who agree with the individual settlements of particular issues accept that the evidence provided is sufficient to support the Settlement Agreement in relation to such settled issue and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make the findings proposed with respect to each of the issues.

Best efforts have been made to identify all of the evidence that relates to each settled issue. The supporting evidence for each settled issue is identified individually by reference to its exhibit number in an abbreviated format such that, for example, Exhibit A4, Tab 1, Schedule 1 will be referred to as A4-1-1. A concise description of each reference is also provided. In this regard, OPG’s response to an interrogatory (“IR”) is described by citing the name of the Party and the number of the IR (e.g. Board Staff IR #1). The identification and listing of the evidence that relates to each issue is provided to assist the Board. The identification and listing of the evidence that relates to each settled issue is not intended to limit any Party who wishes to assert that other evidence is relevant to a particular settled issue.

According to the Guidelines (p. 3), the Parties must consider whether a Settlement Agreement should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. OPG and the other Parties who participated in the Settlement Conference agree that no settled issue requires an adjustment mechanism other than as may be expressly set forth herein.

All of the issues contained in this proposal have been settled by the Parties as a package and none of the provisions of these are severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this comprehensive Settlement Agreement. The distinct issues addressed in this proposal are intricately interrelated, and reductions or increases to the agreed-upon amounts or changes in other agreed-upon parameters may have financial consequences in other areas of this proposal, which may be unacceptable to one or more of the Parties. If the Board does not accept this package in its entirety, then there is no settlement (unless the Parties agree that any portion of the package that the Board does accept may continue as part of a valid Settlement Agreement).

None of the Parties can withdraw from this proposed Settlement Agreement except in accordance with Rule 32.05 of the Rules. It is also agreed that this Agreement is without prejudice to any of the Parties re-examining these issues in any subsequent proceeding and taking positions inconsistent with the resolution of these issues in this Agreement. However, none of the Parties will, in any subsequent proceeding, take a position with respect to the resolution therein of any issue settled in this Agreement which would result in the terms and conditions of this Agreement, and the intent of this Agreement, being altered or abrogated.

Attached to this Settlement Agreement are:

Attachment 1: Contains copies of Ex. H1-1-2, Tables 16 and 17, which showed the calculation of deferral and variance account recovery amounts and payment riders for regulated hydroelectric and nuclear, respectively, and recasts of those tables, labeled Tables 16A and 17A, which show amounts and riders resulting from this agreement. This attachment also contains a recast of Ex. H1-1-2 Table 23, labeled Table 23A, showing calculation of Interim Period Shortfall Riders resulting from this agreement. This attachment also contains a table (17B) which shows the amortization pattern resulting from the 60/40 split described elsewhere in this agreement.

Attachment 2: Contains recasts of Ex. H1-1-2, Tables 14, 14a and a new Table 14c, which show amounts related to the Bruce Lease Net Revenues Variance Account split between derivative and non-derivative portions as set out in this agreement.

Attachment 3: Contains a new table, Table 1, showing the projected revenue requirement impact of Pickering and Bruce accounting service life changes for 2013.

Attachment 4: Contains recasts of Ex. H1-1-2, Tables 21 and 22, which show the calculation of rate and consumer impacts resulting from this agreement.

Summary of the Proposed Settlement

The Parties were able to reach agreement on all issues and have therefore agreed that, subject to OEB approval of this proposed Settlement Agreement, there are no issues that need to be considered through a hearing.

OPG applied to the OEB pursuant to 78.1 of the *Ontario Energy Board Act*, *1998*, for an order or orders approving the disposition of the audited actual balances as of December 31, 2012 in its deferral and variance accounts, except for the balances in the Hydroelectric Incentive Mechanism Variance Account and Hydroelectric Surplus Baseload Generation Variance Account of ($2.4M)[1] and $4.1M[2] respectively, and a portion of the Capacity Refurbishment Variance Account of $2.4M[3].

For purposes of settlement, the Parties agreed to defer the consideration of the balance of $30.2M[4] in the Nuclear Development Variance Account until OPG's next Nuclear cost of service application and to forego the recovery of interest charges for certain accounts.

In the Application, the December 31, 2012 audited actual balances of OPG's deferral and variance accounts totaled $1,274.4M[5]. After the adjustments set out in columns (b) and (d) of Tables 16A and 17A of Attachment 1, the Parties accept the December 31, 2012 audited actual balances for recovery totalling $1,058.3M as set out on an account basis in column (e) of Tables 16A and 17A of Attachment 1 of this Settlement Agreement, consisting of $111.0M for hydroelectric and $947.3M for nuclear deferral and variance accounts.

Based on specified recovery periods, in its Application OPG proposed to recover $103.3M[6] and $849.4M[7] in respect of regulated hydroelectric and nuclear accounts, respectively over 2013 and

[1] See Attachment 1, Table 16, line 3, Columns (a) and (g).

[2] See Attachment 1, Table 16, line 4, Columns (a) and (g).

[3] See Attachment 1, Table 16, line 7, Columns (a) and (g) of $1.1M plus Attachment 1, Table 17, line 4, Column (g) of $1.3M.

[4] See Attachment 1, Table 17, line 2, Column (a).

[5] See Attachment 1, Table 16, line 11, Column (a) of $113.8M plus Table 17, line 11, Column (a) of $1,160.6M, for a total of $1,274.4M.

[6] See Attachment 1, Table 16, line 11, Column (f).

2014, for a total of $952.8M, leaving a forecast balance uncollected as of December 31, 2014 of $321.6 million[8]. As a result of the foregoing adjustments and agreed-upon adjustments to recovery periods and adjustments relating to the recognition of changes to the service lives, for accounting purposes, of the Pickering and Bruce stations, the proposed Settlement Agreement would result in OPG recovering approximately $632.9M ($100.4M[9] for regulated hydroelectric and $532.5M[10] for nuclear) over the period from January 1, 2013 to December 31, 2014. Whereas OPG's initial request would have resulted in an estimated 8% total increase to the regulated hydroelectric and nuclear payment amounts, including riders in effect up to December 31, 2012, the proposed Settlement Agreement, if approved, will result in an estimated 3.6%[11] average total increase over 2013 and 2014.

The Parties agreed on a 60/40 weighting of the $632.9M over the two-year period of 2013 and 2014 which translates into weighted annual total increases in the regulated hydroelectric and nuclear payment amounts, including riders in effect up to December 31, 2012, of approximately 5.4% for 2013 and 1.8% for 2014.

Whereas OPG's initial proposal would have resulted in an estimated 1.4% increase on a typical residential monthly bill of $116.30, the proposed Settlement Agreement reduces this estimated impact by approximately 57% to an approximately 0.6%[12] average increase in a typical residential monthly bill over 2013 and 2014.

The particulars of the Settlement Agreement are detailed below by issue as set out in the Final Issues List approved by the Board.

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7 See Attachment 1, Table 17, line 11, Column (f).

8 See Attachment 1, Table 16, line 11, Column (g) of $10.5M plus Table 17, line 11, Column (g) of $311.1M, for a total of $321.6M.

9 See Attachment 1, Table 16A, line 11, Column (i).

10 See Attachment 1, Table 17A, line 11, Column (i).

11 See Attachment 4, Table 21, line 9, Column (c).

12 See Attachment 4, Table 22, line 5.

B. DEFERRAL AND VARIANCE ACCOUNTS

1. Is the nature or type of amounts recorded in the deferral and variance accounts appropriate?

Settled

There is an agreement to settle this issue as follows.

As indicated in H1-1-1, OPG made entries for 2011 and 2012 in a total of 19 approved deferral and variance accounts in accordance with applicable OEB decisions and orders. In its Application, OPG has requested approval to clear the audited December 31, 2012 balances in all but three of its deferral and variance accounts. The three excluded accounts are the Hydroelectric Incentive Mechanism Variance Account and the Hydroelectric Surplus Baseload Generation Variance Account as well as the hydroelectric portion of, and an amount related to a Darlington refurbishment capital cost variance included in, the Capacity Refurbishment Variance Account (the “Excluded Accounts”). The nature of the amounts recorded in each of OPG’s deferral and variance accounts is described in H1-1-1 and H2-2-1. As part of clearing the account balances, OPG has sought to recover interest that has been recorded using the generic rate of interest for deferral and variance accounts prescribed by the Board for each of the accounts as described in H1-1-1. The audited actual year-end 2012 balances in all accounts of $1,274.4M are shown in H1-1-2 and are the sum of the items in line 11, Column (a) of Tables 16 and 17 in Attachment 1 of $113.8M and $1,160.6M respectively.

The Parties agree that the nature or type of amounts recorded in the deferral and variance accounts as at December 31, 2012 other than the Excluded Accounts, as proposed by OPG, are appropriate subject to the following:

- *Nuclear Liability Deferral Account* - For purposes of this settlement, the Parties agreed to the removal of $1.8M[13] of interest accrued on the debit balance of the account during 2011 and 2012. Therefore, the Parties accept a balance of $206.2M in the account as of December 31, 2012. In addition, the Parties agree that this account should not attract interest for the period after December 31, 2012. The Intervenors did not review the new ONFA Reference Plan, but for the purposes of settlement, assume that the amounts recorded in the account by OPG accurately reflect the total impact arising from the changes to the Reference Plan as described by OPG in its evidence in this proceeding.

- *Bruce Lease Net Revenues Variance Account* - For purposes of this settlement, the Parties agreed to the removal of $5.5M[14] of interest accrued on the debit balance of the account during 2011 and 2012, accepting a balance in the account as of December 31, 2012 of

[13] See Attachment 1, Table 17A, line 1, Column (b) and footnote #3 which identifies the $1.8M in foregone interest.

[14] See Attachment 1, Table 17A, line 5a, Column (b).

$305.1M[15]. The Parties also agree that OPG will not record interest charges on the balance of this account during 2013 or 2014.

- *Nuclear Development Variance Account* – Consideration of the clearance of the balance in this account is deferred until OPG's next cost of service payment amounts proceeding applicable to the nuclear prescribed facilities, in order to allow the amount and prudence of all amounts accumulated in the account to that time to be considered by the Board together.

Approval

Parties in Support: VECC, SEC, CCC, Energy Probe, AMPCO, CME, PWU

Parties Taking No Position: N/A

Evidence

The evidence in relation to this issue includes the following:

H1-1-1	Overview of Deferral and Variance Accounts
H1-1-2	Update for Audited Actual Balances for Deferral and Variance Accounts and Other Information
H2-1-1	Nuclear Liability Deferral Account
H2-1-2	Bruce Lease Net Revenues Variance Account
H2-1-3	Pension and OPEB Cost Variance Account
H2-2-1	Supporting Evidence for Entries into Nuclear Accounts
L-1-1 Staff-01	Board Staff IR #1
L-1-1 Staff-02	Board Staff IR #2
L-1-1 Staff-03	Board Staff IR #3
L-1-1 Staff-04	Board Staff IR #4
L-1-1 Staff-05	Board Staff IR #5
L-1-1 Staff-06	Board Staff IR #6
L-1-1 Staff-07	Board Staff IR #7
L-1-1 Staff-08	Board Staff IR #8
L-1-1 Staff-09	Board Staff IR #9
L-1-1 Staff-10	Board Staff IR #10
L-1-1 Staff-11	Board Staff IR #11
L-1-1 Staff-12	Board Staff IR #12

[15] See Attachment 1, Table 17A, lines 5 and 5a, Column (c) of $230.3M and $74.8M respectively for a total of $305.1M.

L-1-1 Staff-13	Board Staff IR #13
L-1-1 Staff-14	Board Staff IR #14
L-1-2 AMPCO-01	AMPCO IR #1
L-1-2 AMPCO-02	AMPCO IR #2
L-1-4 CCC-01	CCC IR #1
L-1-4 CCC-02	CCC IR #2
L-1-4 CCC-03	CCC IR #3
L-1-4 CCC-04	CCC IR #4
L-1-6 PWU-01	PWU IR #1
L-1-7 SEC-01	SEC IR #1
L-1-7 SEC-02	SEC IR #2
L-1-7 SEC-03	SEC IR #3
L-1-7 SEC-04	SEC IR #4
L-1-7 SEC-05	SEC IR #5
L-1-7 SEC-06	SEC IR #6
L-1-7 SEC-07	SEC IR #7
L-1-7 SEC-08	SEC IR #8
L-1-7 SEC-09	SEC IR #9
L-1-7 SEC-10	SEC IR #10
L-1-7 SEC-11	SEC IR #11
L-1-7 SEC-12	SEC IR #12
L-1-7 SEC-13	SEC IR #13
L-1-7 SEC-14	SEC IR #14
L-1-7 SEC-15	SEC IR #15
L-1-7 SEC-16	SEC IR #16
L-1-7 SEC-17	SEC IR #17
L-1-7 SEC-18	SEC IR #18
L-1-7 SEC-19	SEC IR #19
L-1-7 SEC-20	SEC IR #20
L-1-7 SEC-21	SEC IR #21
L-1-7 SEC-22	SEC IR #22
L-1-7 SEC-23	SEC IR #23
L-1-7 SEC-24	SEC IR #24

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

Settled

There is an agreement to settle this issue as follows.

OPG filed an update to its Application on February 8, 2013. Included in the update was H1-1-2 Table 1, which provides the audited actual balances for the deferral and variance accounts as at December 31, 2012. These amounts were replicated in Column (a) of H1-1-2 Table 16 and Table 17 for regulated hydroelectric and nuclear, respectively. Overall, the total audited actual December 31, 2012 balances for all of OPG's accounts are debit balances of $113.8M for regulated hydroelectric and $1,160.6M for nuclear. H1-1-2 Table 16 and 17 is attached to this Settlement Agreement as part of Attachment No. 1. Taking into account the Excluded Accounts, the total audited actual December 31, 2012 balances for recovery proposed in this Application are debit balances of $110.9M for regulated hydroelectric and $1,159.2M for nuclear as set out in column (b) of H1-1-2 Tables 16 and 17, respectively, in Attachment 1.

Taking into account both the Excluded Accounts and the interest adjustments set out in Section 1, and other adjustments and advances set out elsewhere in this Settlement Agreement, the total audited actual December 31, 2012 balances for recovery in this Application by OPG are debit balances of $111.0M for regulated hydroelectric and $947.3M for nuclear as set out in column (e) of Tables 16A and 17A respectively of Attachment No. 1 to this Settlement Agreement. The Parties agree that the balances for recovery in each of the deferral and variance accounts set out in Attachment No. 1 are appropriate.

Approval

Parties in Support: VECC, SEC, CCC, Energy Probe, AMPCO, CME, PWU

Parties Taking No Position: N/A

Evidence

The evidence in relation to this issue includes the following:

H1-1-1	Overview of Deferral and Variance Accounts
H1-1-2	Update for Audited Actual Balances for Deferral and Variance Accounts and Other Information
H2-1-1	Nuclear Liability Deferral Account
H2-1-2	Bruce Lease Net Revenues Variance Account
H2-1-3	Pension and OPEB Cost Variance Account
H2-2-1	Supporting Evidence for Entries into Nuclear Accounts

L-2-1 Staff-15	Board Staff IR #15
L-2-1 Staff-16	Board Staff IR #16
L-2-1 Staff-17	Board Staff IR #17
L-2-1 Staff-18	Board Staff IR #18
L-2-1 Staff-19	Board Staff IR #19
L-2-1 Staff-20	Board Staff IR #20
L-2-1 Staff-21	Board Staff IR #21
L-2-1 Staff-22	Board Staff IR #22
L-2-1 Staff-23	Board Staff IR #23
L-2-1 Staff-24	Board Staff IR #24
L-2-2 AMPCO-03	AMPCO IR #3
L-2-2 AMPCO-04	AMPCO IR #4
L-2-2 AMPCO-05	AMPCO IR #5
L-2-2 AMPCO-06	AMPCO IR #6
L-2-2 AMPCO-07	AMPCO IR #7
L-2-2 AMPCO-08	AMPCO IR #8
L-2-2 AMPCO-09	AMPCO IR #9
L-2-2 AMPCO-10	AMPCO IR #10
L-2-2 AMPCO-11	AMPCO IR #11
L-2-4 CCC-05	CCC IR #5
L-2-4 CCC-06	CCC IR #6
L-2-6 PWU-02	PWU IR #2

3. Are the proposed rate riders and disposition periods to dispose of the account balances appropriate?

Settled

There is an agreement to settle this issue as follows.

In its Application, OPG proposed to clear the audited actual December 31, 2012 balances in the regulated hydroelectric deferral and variance accounts on a straight line basis with the Pension and OPEB Cost Variance Account balance being amortized over a 48-month period from January 1, 2013 to December 31, 2016 and all other account balances being amortized over a 24-month period from January 1, 2013 to December 31, 2014. OPG also proposed to clear the audited actual December 31, 2012 balances in the nuclear deferral and variance accounts on a straight line basis with the balances of the Pension and OPEB Cost Variance Account and the Bruce Lease Net Revenues Variance Account being amortized over a 48-month period from January 1, 2013 to December 31, 2016 and all other account balances being amortized over a 24-month period from January 1, 2013 to December 31, 2014.

As set out in H1-1-2 Table 16 of Attachment No. 1 of this Settlement Agreement, the total proposed amortization amount for regulated hydroelectric is $103.3M over the 24-month period from January 1, 2013 to December 31, 2014. The resulting 24-month amortization amount is proposed to be divided by the EB-2010-0008 approved test period regulated hydroelectric production forecast to calculate the payment amount rider. Based on this methodology, OPG was seeking a payment rider of $2.60/MWh for 2013 and 2014 in respect of regulated hydroelectric production, effective January 1, 2013.

As set out in H1-1-2 Table 17 of Attachment No. 1 of this Settlement Agreement, the total proposed amortization amount for nuclear was $849.4M over the 24-month period from January 1, 2013 to December 31, 2014. The resulting total amortization amount is proposed to be divided by the EB-2010-0008 approved test period nuclear production forecast to calculate the payment amount rider. Based on this methodology, OPG was seeking a payment rider of $8.34/MWh for 2013 and 2014 in respect of nuclear production, effective January1, 2013.

Recovery Period

For the purposes of reaching a settlement, the Parties agree that the recovery periods for disposing of the account balances and the amortization amounts for 2013 and 2014 for each account as set out in columns (g), (h) and (i) of Tables 16A and 17A of Attachment No.1 are appropriate. These include the following changes relative to OPG’s Application:

Pension and OPEB Cost Variance Account**:** As indicated in section 4.5 of H1-1-1, this account was established in EB-2011-0090 for the purpose of recording the difference between (i) the pension and OPEB costs, plus related income tax PILs, reflected in the EB-2010-0008 decision and the resulting payment amounts order, and (ii) OPG's actual pension and OPEB costs, and associated tax impacts, for the test period for the prescribed generation facilities. The audited actual December 31, 2012 balance in this account is $324.2M, comprised of $15.1M[16] for regulated hydroelectric and $309.1M[17] for nuclear.

The Parties have agreed that this will be an ongoing account. The Parties have also agreed to a disposition methodology for the December 31, 2012 balance of $324.2M as described in further detail below.

The Parties have divided the December 31, 2012 balance in this account into two parts, the "Historic Recovery" and the "Future Recovery". The clearance of the Historic Recovery portion is intended to adjust for the lack of recoveries of additional pension and OPEB amounts in 2011 and 2012 by recovering that portion of the account balance over two years. The Future Recovery portion comprising the remaining December 31, 2012 balance is recovered over 12 years. With the exception of the Historic Recovery (addressed below), the clearance of the account balance will be done over a period equivalent to the current expected average remaining service lives of OPG's employees ("EARSL"), which is 12 years.

The Parties agree that 2/12ths of the balance of the account as at December 31, 2012, including interest accrued to such date together with interest projected to accrue on such 2/12ths of the balance in 2013 and 2014 (the "Historic Recovery"), will be cleared and recovered over the two-year period from January 1, 2013 to December 31, 2014. The remaining 10/12ths of the balance of the account (the "Future Recovery") will be cleared and recovered over a 12-year period from January 1, 2013 to December 31, 2024.

To the extent the actual interest amounts during 2013 and 2014 related to the Historic Recovery are different from those used in establishing amortization amounts in this proceeding, OPG will record such differences in the Hydroelectric and Nuclear Deferral/Variance Over/Under Recovery Variance Accounts for administrative simplicity.

The amortization term and methodology for the recovery or refund of amounts being posted to the account after December 31, 2012 will be addressed in OPG's next payment amounts application to the Board. For clarity, in that proceeding, OPG and the intervenors are free to propose whatever amortization methodology or period that they feel makes sense in the circumstances to address the recovery or refund of the incremental balance (i.e., the new additions and interest, if applicable, accumulated after December 31, 2012) in the account.

The account will continue to be used to record all changes to pension and OPEB costs, whether up or down, for any reason, including changes in costs resulting from changes in pension and OPEB obligations.

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[16] See Attachment 1, Table 16, line 8, Column (a).

[17] See Attachment 1, Table 17, line 8, Column (a).

With respect to the continuation of the account, see Section 4 of this Settlement Agreement.

Bruce Lease Net Revenues Variance Account: As indicated in section 6.6 of H1-1-1, this account was established by the OEB to capture differences between the forecast revenues and costs related to the Bruce Lease agreement that are factored into the approved nuclear revenue requirement, and OPG's actual revenues and costs in respect of the Bruce facilities. The Board determined in EB-2007-0905 that the calculation of the entries to this account would be based on GAAP accounting rules.

The 2012 year-end audited actual balance (including interest) in this account is $310.5M. A component of this balance relates to reductions in supplemental rent revenue during 2011 and 2012 resulting from the increase in the fair value of a derivative, calculated in accordance with GAAP, in respect of an expected future partial supplemental rent rebate, pursuant to the Bruce Lease Agreement.

Bruce Power L.P. ("Bruce Power") pays a variable amount of supplemental rent to OPG. The supplemental rent is currently in the order of $31M per unit per year (in 2012 dollars) and is applied on the basis of the number of generating units operational in a given calendar year. Supplemental rent is also dependent on the Hourly Ontario Energy Price ("HOEP"). A provision in the Bruce Lease requires a partial rebate by OPG to Bruce Power of the supplemental rent payments for the Bruce units in a calendar year where the annual arithmetic average of the HOEP ("Average HOEP") falls below $30/MWh, and certain other conditions are met.

This potential reduction to revenue in the future, arising out of the terms of the Bruce Lease, must be accounted for as a derivative at fair value under GAAP. The derivative value represents a liability by considering, on a present value basis, the probability of OPG having to rebate future amounts of supplemental rent, and treating that present value as a reduction to revenue recognized in the current period in accordance with GAAP. For example, the present value of the current probability-weighted expectation of having to pay a supplemental rent rebate for 2015 was reflected as a reduction in revenue (and an increase in the derivative liability) in 2012. Future revenue from the supplemental rent itself (i.e., before any rebate) is not recognized under GAAP in the current period (i.e., rent revenue is recognized in the period to which the rent actually relates), leading to a potential mismatch in which the liability for the rebate is brought forward but the rent to which it relates is not.

A valuation model calculates the derivative liability by multiplying the present value, as of the valuation date, of the projected rebate amount (determined using an estimated CPI for each year as required by the terms of the lease agreement) for each of the remaining years (including the current year) of the accounting service life of the applicable Bruce units (currently Bruce B), by that year's estimated probability that the rebate will be triggered.

The Parties have agreed to a new disposition methodology for the clearance of the balance in this variance account such that the impact of the derivative accounting is recovered (or refunded) differently on an on-going basis from the balance in the account in relation to the non-derivative portion. The recovery of the derivative component will be matched to the related revenue.

To facilitate this new disposition methodology, this account will be divided into two sub-accounts,

1. The balance in the account relating to the derivative for the Bruce Lease (including associated income tax impacts on Bruce Lease net revenues calculated in accordance with GAAP) and the rent rebates associated with the supplemental rent revenue, and

2. The balance in the account relating to the non-derivative aspects of the account.

The agreed balance as at December 31, 2012 of $305.0M is split $74.8M and $230.3M for the non-derivative and derivative portions, respectively, for inclusion in the sub-accounts and clearance.

The non-derivative sub-account is to be recovered on a straight-line basis over a four year-period from January 1, 2013 to December 31, 2016 using the method proposed in H1-2-1. The resulting amortization for this sub-account of the account is $18.7M for each of 2013 and 2014.

The intention with the derivative sub-account is that the amount recovered from ratepayers in any year will be equal to the amount expected to be paid as a rent rebate for that year (i.e. rebate payment made by OPG to Bruce Power). The intended result is that the rate impacts of the rent rebate, and the supplemental rent to which it relates, will be matched in each year. To reflect the fact that amounts recovered to date (as at December 31, 2012) on this part of the account exceed rent rebates incurred to date, an adjustment to the amount to be cleared in 2013 is included. Once that adjustment is made, the impacts of the rebate, and the rate recovery of those impacts, should be concurrent. In order to achieve this result practically, each time the balance in the Bruce Lease Net Revenues Variance Account is cleared, the amortization amounts for a given year for the derivative portion of the balance will be set to equal to OPG's forecast of the tax adjusted supplemental rent rebate payable to Bruce Power for that year, with any variance between the forecast and actual amounts of the rebate (and associated income taxes as described above) included as adjustments to amortization amounts determined the next time the account balance is cleared[18].

Therefore, the amortization amounts for the derivative portion of the December 31, 2012 account balance is OPG's forecast of supplemental rent rebate payable to Bruce Power for each of 2013

[18] By way of example, the rebate amount, net of tax, in 2013 is expected to be $60.3M, but as noted below there is a credit of $54.9M for prior amounts collected from ratepayers. Thus, $5.3M will be collected in 2013. If the rebate amount, net of tax, in 2013 is actually $50M, OPG will be treated as having an overcollection of $10.3M in the account. The rebate amount, net of tax, in 2014 is expected to be $62.2M, and the total recovery has been set accordingly. In this example, the recovery would be adjusted in 2014, or whenever the payment riders for the clearance of deferral and variance accounts are next reset, to reflect the $10.3M overcollection as of the end of 2013.

and 2014, with credit given to ratepayers for the amount by which recovery from ratepayers in respect of the derivative portion (including taxes as described above) during the period from April 1, 2008 to December 31, 2012 has exceeded the total amount of supplemental rent rebates (and associated tax impacts as described above) for that period. OPG has collected $161.2M from ratepayers in respect of the derivative portion during 2011 and 2012; no amounts were collected for the period from April 1, 2008 to December 31, 2010. The rebate amounts to Bruce Power payable by OPG (and associated tax impacts as described above) during the period from April 1, 2008 to December 31, 2012 totaled $106.3M[19], resulting in a "prior period" credit to ratepayers of $54.9M[20] to be applied against the amortization amount for 2013. (The rebate was payable by OPG for 2009 and 2012 during this period.) Additionally, OPG expects to incur rebate amounts (and associated tax impacts as described above) payable of $60.3M for 2013 and $62.2M for 2014. After adjusting these amounts to reflect the $54.9M credit, the resulting amortization for this portion of the account is $5.3M[21] for 2013 and $62.2M[22] for 2014 (amounts do not add due to rounding).

Effective January 1, 2013, the Parties agree to establish separate sub-accounts for the derivative and non-derivative portions of the variance account and continue the following recovery treatment for the derivative sub-account: the amount to be cleared each year, starting in 2013, shall be equal to the amount of the rebate forecast to be payable to Bruce Power for that year by OPG and associated income tax impacts as described above less the difference between the following amounts to the extent this difference has not yet been credited to, or recovered from, ratepayers:

(i) cumulative amount recovered from ratepayers for the derivative portion since April 1, 2008; and

(ii) cumulative amount of actual rent rebates and associated income taxes (as described above) incurred by OPG since April 1, 2008.

For greater clarity, the Parties are not in this Agreement agreeing to any change in the previously-approved manner of calculation of the additions to the Bruce Lease Net Revenues Variance Account.

Nuclear Liability Deferral Account: OPG proposed to clear the December 31, 2012 audited actual account balance of $208.0M (H1-1-2 table 1c) over a two-year period (Ex H1-2-1, Section 5.0). O. Reg. 53/05 requires that amounts recorded in this account be determined as the revenue requirement impact of changes in OPG's nuclear decommissioning and nuclear waste and used fuel management liabilities ("Nuclear Liabilities"), between the liability arising from an

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[19] $106.3M from Attachment 2, Table 14c, line 3 plus line 12 minus line 13

[20] $161.2M from Attachment 2, Table 14c, line 11 less $106.3M

[21] See Attachment 2, Table 14c, line 15.

[22] See Attachment 2, Table 14c, line 16.

approved Reference Plan pursuant to the Ontario Nuclear Funds Agreement ("ONFA") incorporated into the Board's most recent order under section 78.1 of the *Ontario Energy Board Act, 1998* and the liability arising from the current approved ONFA Reference Plan. The revenue requirement impact as defined in O. Reg. 53/05 Section 6(2)7 is described in Ex H2-1-1 Section 5.0.

At the end of 2012, OPG, based on a high confidence level associated with continued operations of the Pickering Units 5-8 , extended the service life, for accounting purposes, for these units (i.e., Pickering B) and correspondingly revised the service life of Pickering Units 1 and 4 (i.e., Pickering A), effective December 31, 2012 (L-2-1 Staff-19). At the same time, OPG also extended the service lives, for accounting purposes, of both Bruce A and Bruce B stations, effective December 31, 2012, based on OPG having high confidence that the condition of the pressure tubes for the Bruce units should allow them to operate longer, consistent with Bruce Power's intent to do so (L-2-2 AMPCO-06). OPG's evidence indicates that the Pickering and Bruce service lives that OPG established effective December 31, 2012 are consistent with those reflected in the 2012 ONFA Reference Plan approved effective January 1, 2012 (L-2-1, Staff 19). The Plan itself is not in evidence in this proceeding. However, for the purposes of settlement, the Intervenors accept OPG's evidence on the contents of that Plan[23]. The Parties acknowledge that the revenue requirement impact of Nuclear Liabilities for the prescribed facilities will reflect the above service life changes starting in 2013 and, therefore, will be reflected in additions to the Nuclear Liability Deferral Account in 2013 (in the absence of a change in current nuclear payment amounts excluding riders).

The Parties have agreed that the impacts of the above changes to the station service lives will be addressed in two parts for the purposes of this Settlement Agreement. The first part will comprise an advancement of an estimated credit of $81.4M arising from the revenue requirement impact of Nuclear Liabilities for the prescribed facilities (other than reduction in depreciation expense and associated tax impacts for the non-asset retirement cost components) which will reduce the balance in this account over its clearance period as discussed in further detail below. The second part will result in an adjustment of $46.9M per year for the lower depreciation expense and the associated lower income taxes in relation to the non-asset retirement cost components of the Pickering fixed asset balances, which will be captured in a new account, Pickering Life Extension Depreciation Variance Account, discussed in further detail in Section D. The adjustments noted in these two parts will reduce overall settlement balance for recovery by a total of $175.2M.

For the purposes of settlement, the Parties have agreed to a two-year recovery period from January 1, 2013 to December 31, 2014 of the adjusted December 31, 2012 balance of $206.2M in the deferral account. The Parties further have agreed to advance the refund to ratepayers of

[23] Service lives for purposes of the new ONFA Reference Plan were extended prior to OPG recognizing them for accounting purposes, since ONFA takes a longer term view and anticipated that such a change was going to take place during the term of the ONFA Reference Plan.

an estimated credit of $81.4M in respect of the projected revenue requirement impact in 2013 of Nuclear Liabilities for the prescribed facilities resulting from the above service life changes (line 17 minus the sum of lines 5 and 13 from Table 1 found in Attachment No. 3 to this agreement). As such, the 2013 and 2014 amortization amounts for the deferral account will reflect this credit. Accordingly, the net amount of total amortization for 2013 and 2014 is $124.8M.

In order for the Nuclear Liability Deferral Account, as presently defined in O. Reg. 53/05, to operate correctly subsequent to 2012, OPG will record amortization based on $124.8M and account additions in the normal course. Starting in 2013, in the absence of changes in nuclear payment amounts as described above, the additions to the account will, in the normal course, be inherently net of the credit for the impact of the service life changes. As such, both the amortization and the additions in the normal course will reflect the impact of the service life changes effectively in an offsetting manner, the balance in the account at any point in time will reflect the appropriate outstanding amount.

Amortization and Payment Riders

In the Application, the total balance of deferral and variance accounts for recovery for regulated hydroelectric as at December 31, 2012 was $110.9M[24] and for nuclear was $1,159.2M[25], resulting in a total balance of deferral and variance accounts for recovery of $1,270.1M. Based on the proposed recovery periods, the total amortization amount over 2013 and 2014 for regulated hydroelectric was $103.3M[26] and the total amortization amount over 2013 and 2014 for nuclear was $849.4M[27], resulting in a total amount of $952.7M. Employing the OEB-approved regulated hydroelectric and nuclear production levels from EB-2010-0008, the resulting overall change in the existing payment amounts including riders would have been approximately 8%.

The implementation of the proposed Settlement Agreement would result in OPG recovering a total amortization amount for both regulated hydroelectric and nuclear of $632.9M[28] over the period from January 1, 2013 to December 31, 2014. As shown in Attachment No. 4 to this Settlement Agreement the Settlement Agreement results in an estimated 3.6% average total impact to payment amounts over 2013 and 2014.

The Parties have agreed on a 60/40 weighting for the recovery of the amortization amount of $632.9M over the 2013-2014 two-year period. Any annual amortization amounts cited in this agreement are unadjusted for this 60/40 weighting. Amortization actually recorded in 2013 and

[24] See Attachment 1, Table 16, line 11, Column (b).

[25] See Attachment 1, Table 17, line 11, Column (b).

[26] See Attachment 1, Table 16, line 11, Column (f).

[27] See Attachment 1, Table 17, line 11, Column (f).

[28] See Attachment 1, Table 16A, line 11, Column (i) of $100.4M plus Table17A, line 11, Column (i) of $532.5M for a total of $632.9M.

2014 will be 60% and 40%, respectively of the total agreed amounts for 2013 and 2014, as shown in Attachment 1, Table 17B.

This 60/40 weighting translates into weighted annual increases in the regulated hydroelectric and nuclear payment amounts including riders of approximately 5.4% for 2013 and 1.8% for 2014, relative to the current payment amounts including rate riders in effect up to December 31, 2012. Whereas OPG's initial proposal would have resulted in an estimated 1.4% increase on a typical residential monthly bill, the proposed Settlement Agreement will reduce this estimated impact by approximately 57% to an approximately 0.6%[29] average increase over 2013 and 2014 in a typical residential monthly bill. The resulting regulated hydroelectric and nuclear riders for 2013 are \$3.04/MWh[30] and \$6.27/MWh[31], respectively. The resulting regulated hydroelectric and nuclear riders for 2014 are \$2.02/MWh[32] and \$4.18/MWh[33], respectively.

Interim Rider

OPG has requested separate regulated hydroelectric and nuclear payment riders, effective January 1, 2013, so as to recover the audited actual deferral and variance account balances as at December 31, 2012 for the accounts that it seeks to clear. OPG is also seeking to recover the differences between amounts recovered during the period from January 1, 2013 until the implementation date of new payment amounts based on the \$4.33/MWh interim rider for nuclear and nil for regulated hydroelectric (as per the Board's Decision and Procedural Order No. 1 dated November 6, 2012) and those based on the new riders effective January 1, 2013. OPG proposed to affect this recovery through Interim Period Shortfall Riders for each of regulated hydroelectric and nuclear production (as set out in H1-2-1). The Parties have agreed to an effective date of January 1, 2013 and an implementation date of March 1, 2013.

The Parties have agreed that the Interim Period Shortfall Riders shall be calculated as set out in H1-2-1, Section 6 as modified for the introduction of the weighted payment riders in 2013 and 2014. The period over which the Interim Period Shortfall Riders (regulated hydroelectric and nuclear) shall be collected will be from the implementation date to December 31, 2013, rather than to December 31, 2014. The Interim Period Shortfall Riders shall be calculated so as to maintain the recovery between 2013 and 2014 at \$379.8M and \$253.2M respectively, as previously set out. The resulting Interim Period Shortfall Riders assuming implementation dates of March 1, 2013 or April 1, 2013 are calculated as shown in Attachment 1, Table 23A.

Approval

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[29] See Attachment 4, Table 22, line 5.

[30] See Attachment 1, Table 16A, line 13, Column (g).

[31] See Attachment 1, Table 17A, line 13, Column (g).

[32] See Attachment 1, Table 16A, line 13, Column (h).

[33] See Attachment 1, Table 17A, line 13, Column (h).

Parties in Support:	VECC, SEC, CCC, Energy Probe, AMPCO, CME,
Parties Taking No Position:	PWU

Evidence

The evidence in relation to this issue includes the following:

H1-2-1	Clearance of Deferral and Variance Accounts
I1-1-1	Regulated Hydroelectric and Nuclear Riders
I1-1-2	Rate and Consumer Impact
L-3-1 Staff-25	Board Staff IR #25
L-3-1 Staff-26	Board Staff IR #26
L-3-1 Staff-27	Board Staff IR #27
L-3-1 Staff-28	Board Staff IR #28
L-3-2 AMPCO-12	AMPCO IR #12
L-3-2 AMPCO-13	AMPCO IR #13
L-3-2 AMPCO-14	AMPCO IR #14
L-3-2 AMPCO-15	AMPCO IR #15
L-3-2 AMPCO-16	AMPCO IR #16
L-3-3 CME-01	CME IR #1
L-3-4 CCC-07	CCC IR #7
L-3-4 CCC-08	CCC IR #8
L-3-5 EP-01	EP IR #1
L-3-5 EP-02	EP IR #2
L-3-7 SEC-25	SEC IR #25
L-3-7 SEC-26	SEC IR #26
L-3-7 SEC-27	SEC IR #27
L-3-7 SEC-28	SEC IR #28
L-3-7 SEC-29	SEC IR #29
L-3-7 SEC-30	SEC IR #30
L-3-7 SEC-31	SEC IR #31

4. Is the proposed continuation of the Pension and OPEB Cost Variance Account until the effective date of the next payment amounts order appropriate?

Settled

There is an agreement to settle this issue as follows.

The Pension and OPEB Cost Variance Account has a specified end date of December 31, 2012. In its Decision and Procedural Order No. 1 dated November 6, 2012, the OEB granted interim authority to continue posting entries into this account from January 1, 2013 until such date as will be determined in the Board's final order in the current proceeding. In addition to such interim authority, as described in section 4.0 of H2-1-3, OPG has requested authorization to continue recording entries in the Pension and OPEB Cost Variance Account until the effective date of OPG's next payment amounts order.

The Parties agree that the Pension and OPEB Cost Variance Account will be ongoing without a prescribed end date. Recovery of amounts accumulated in this account starting in 2013 (excluding interest related to the 2/12ths portion of the December 31, 2012 balance discussed in Section 3 above) will be as per Section 3 of this Settlement Agreement. For purposes of settlement, the Parties agree that OPG will not record interest charges on the outstanding balance in 2013 and 2014 (except for the 2/12ths portion as described in Section 3 above). The Parties agree that OPG will include, in the first applicable payment amounts proceeding initiated for a period after 2014, consideration of whether this account should include interest commencing in 2015. Subject to the Board's decision in that proceeding, OPG will provisionally resume recording interest charges effective January 1, 2015 on the entire balance remaining in the account at that time, without prejudice to intervenors arguing against the recording of interest charges at any time after 2014 in that future proceeding.

For greater clarity, additions to the ongoing variance account, including those for income tax impacts, will continue to be calculated and recorded in a manner consistent with that used for 2011 and 2012. Actual pension and OPEB costs for the purposes of the variance account will be calculated using the same accounting standards as those used to derive the forecast of such costs included in the payment amounts then in effect. While the EB-2010-0008 payment amounts (excluding riders) remain in effect, actual costs will be calculated in accordance with Canadian GAAP until new payment amounts are established on the basis of USGAAP, at which time USGAAP will become the basis of calculating the corresponding costs.[34]

[34] For details on accounting treatment, please see the following references:

- EB-2010-0008, Exhibit F4-3-1, Section 6.3
- EB-2012-0002, Exhibit H1-1-2, Attachment 2, Note 2
- EB-2012-0002, Exhibit H1-1-2, Attachment 3, Pages 6-8

Approval

Parties in Support:	VECC, SEC, CCC, Energy Probe, AMPCO, CME, PWU
Parties Taking No Position:	N/A

Evidence

The evidence in relation to this issue includes the following:

H1-3-1	Continuation of Deferral and Variance Accounts
H2-1-3	Pension and OPEB Cost Variance Account
L-4-1 Staff-29	Board Staff IR #29
L-4-1 Staff-30	Board Staff IR #30
L-4-5 EP-03	EP IR #3
L-4-7 SEC-32	SEC IR #32

5. Is the proposed continuation of other deferral and variance accounts appropriate?

Settled

There is an agreement to settle this issue as follows.

As indicated in H1-1-1 (pp. 1-2), the Pickering A Return to Service Deferral Account was terminated on December 31, 2011 and each of the Hydroelectric Interim Period Shortfall (Rider D) Variance Account, the Transmission Outages and Restrictions Variance Account, the Nuclear Fuel Cost Variance Account and the Nuclear Interim Period Shortfall (Rider B) Variance Account were terminated on December 31, 2012, in accordance with the Board's EB-2010-0008 order.

In addition to the Pension and OPEB Cost Variance Account continued as agreed in Section 4 above and unless expressly stated otherwise in this agreement, the Parties agree that the continuation of all other deferral and variance accounts as outlined in OPG's application at H1-3-1 is appropriate.

Approval

Parties in Support:	VECC, SEC, CCC, Energy Probe, AMPCO, CME, PWU
Parties Taking No Position:	N/A

Evidence

The evidence in relation to this issue includes the following:

H1-1-1	Overview of Deferral and Variance Accounts
H1-3-1	Continuation of Deferral and Variance Accounts
L-5-2 AMPCO-17	AMPCO IR #17
L-5-4 CCC-09	CCC IR #9

C. USGAAP FOR REGULATORY PURPOSES

6. Is the request to adopt USGAAP for regulatory accounting, reporting and rate-making purposes appropriate?

Settled

There is an agreement to settle this issue as follows.

For the purposes of reaching a settlement, the Parties agree that OPG's adoption of USGAAP for regulatory accounting, reporting and rate-making purposes effective January 1, 2012 is appropriate.

Approval

Parties in Support:	VECC, SEC, CCC, Energy Probe, AMPCO, CME, PWU
Parties Taking No Position:	N/A

Evidence

The evidence in relation to this issue includes the following:

A3-1-2	Approval to Use USGAAP
H1-1-1, 4.6	Overview of Deferral and Variance Accounts - Impact for USGAAP Deferral Account
H1-1-1, Table 6	Impact for USGAAP Deferral Account
H1-1-2, 3.1.2	Update for Audited Actual Balances for Deferral and Variance Accounts and Other Information - Impact for USGAAP Deferral Account
H1-1-2, Table 6	Impact for USGAAP Deferral Account
L-6-1 Staff-31	Board Staff IR #31
L-6-1 Staff-32	Board Staff IR #32
L-6-1 Staff-33	Board Staff IR #33
L-6-1 Staff-34	Board Staff IR #34
L-6-1 Staff-35	Board Staff IR #35
L-6-1 Staff-36	Board Staff IR #36
L-6-1 Staff-37	Board Staff IR #37
L-6-1 Staff-38	Board Staff IR #38
L-6-1 Staff-39	Board Staff IR #39
L-6-1 Staff-40	Board Staff IR #40
L-6-1 Staff-41	Board Staff IR #41
L-6-1 Staff-42	Board Staff IR #42
L-6-1 Staff-43	Board Staff IR #43

L-6-2 AMPCO-18	AMPCO IR #18
L-6-5 EP-04	EP IR #4

7. Is OPG's forecast of accounting differences between CGAAP and USGAAP appropriate?

Settled

There is an agreement to settle this issue as follows.

The implications of the transition to USGAAP on OPG's regulatory accounting are set out by OPG in A3-1-2, which describes how OPG's regulatory accounting would be affected in the areas of (a) long term disability ("LTD") benefit plan costs, (b) Scientific Research and Experimental Development investment tax credits, and (c) Bruce Lease revenues and costs. Of these, OPG states that only the change in the treatment of actuarial losses and gains and past service costs associated with OPG's LTD plan and related income tax impacts would have a financial impact on OPG's prescribed assets. Specifically, OPG recorded a debit of $63.1M ($2.8M[35] for regulated hydroelectric and $60.3M[36] for nuclear) for this financial impact in the Impact for USGAAP Deferral Account for 2012, including $0.9M of interest.

For the purposes of reaching a settlement, the Intervenors accept OPG's evidence that the accounting differences between CGAAP and USGAAP and resulting financial impacts and effects on regulatory accounting are as identified by OPG, and they are appropriate. The Parties further agree that the $63.1M balance in the Impact for USGAAP Deferral Account should be recovered as proposed by OPG. The Parties also agree no further amounts will be recorded in the Impact for USGAAP Deferral Account after December 31, 2012, with the exception of interest and amortization.

Approval

Parties in Support:	VECC, SEC, CCC, Energy Probe, AMPCO, CME, PWU
Parties Taking No Position:	N/A

Evidence

The evidence in relation to this issue includes the following:

A3-1-2	Approval to Use USGAAP
H1-1-1, 4.6	Overview of Deferral and Variance Accounts - Impact for USGAAP Deferral Account
H1-1-1, Table 6	Impact for USGAAP Deferral Account

[35] See Attachment 1, Table 16, line 9, Column (a).

[36] See Attachment 1, Table 17, line 9, Column (a).

H1-1-2, 3.1.2	Update for Audited Actual Balances for Deferral and Variance Accounts and Other Information - Impact for USGAAP Deferral Account
H1-1-2, Table 6	Impact for USGAAP Deferral Account
L-7-1 Staff-44	Board Staff IR #44
L-7-1 Staff-45	Board Staff IR #45
L-7-2 AMPCO-19	AMPCO IR #19
L-7-7 SEC-33	SEC IR #33
L-7-7 SEC-34	SEC IR #34
L-7-7 SEC-35	SEC IR #35

D. OTHER ASPECTS OF SETTLEMENT

For the purposes of reaching a settlement, the Parties further agree, as part of the overall settlement, as follows:

- *Nuclear Liability Deferral Account* – If, other than through an ONFA Reference Plan update process, OPG proposes to effect an accounting change impacting the calculation of the Nuclear Liabilities and resulting in a revenue requirement impact for the prescribed facilities that is neither reflected in the current or proposed payment amounts nor recorded in the Nuclear Liability Deferral Account (including, without limitation, any change in the useful lives of any asset for depreciation or amortization purposes), then OPG shall seek an accounting order from the OEB, on notice to all of the intervenors in the present proceeding, so that the OEB may consider how to address the impact of such proposed accounting change until OPG's next cost of service payment amounts application for the prescribed nuclear facilities. The obligation to apply for such accounting orders shall be governed by a materiality threshold for the annualized revenue requirement impact for the prescribed facilities of $10M. The parties agree that the above obligation for OPG is effective January 1, 2013 and will apply on an ongoing basis without a prescribed end date, notwithstanding the establishment of new payment amounts for prescribed nuclear facilities in the future.

- *Pickering Life Extension Depreciation Variance Account* - The changes in the service lives, for depreciation purposes, of Pickering described in Section 3 above result in a reduction in depreciation expense for the non-asset retirement cost components of the Pickering fixed asset balances effective January 1, 2013, relative to the amounts reflected in the EB-2010-0008 nuclear payment amount. For purposes of this settlement agreement, OPG agrees to credit customers with a $46.9M benefit, per year, for the lower depreciation expense of $35.2M[37] and associated lower income tax impacts of $11.7M[38]. OPG will establish a Pickering Life Extension Depreciation Variance Account to record the credit amount of $46.9M over the course of a year at approximately $3.9M per month, for the period from January 1, 2013 until the effective date of new nuclear payment amounts (excluding riders) reflecting the revised service lives. The Parties have agreed that the payment rider to clear the agreed-upon December 31, 2012 balances in this proceeding will be established such that the year-end (and month-end) amount in this new account in each of 2013 and 2014 is expected to be zero. Specifically, the nuclear rider has been calculated by reducing amortization amounts for 2013 and 2014 otherwise resulting from this agreement by $46.9M per year, in order to reflect the credit to customers for the changes in the Pickering service lives. As the account is designed such that the credit reflected in the nuclear payment rider is matched to the reduction in

[37] See Attachment 3, Table 1, line 5.
[38] See Attachment 3, Table 1, line 13.

revenue requirement for depreciation expense and associated income tax impact, no interest will be recorded in this account.

For greater clarity, the Parties acknowledge that should new nuclear payment amounts reflecting the revised service lives be established with an effective date prior to December 31, 2014, amortization based on the $46.9M per year credit would continue to be recorded until December 31, 2014, thereby resulting in a debit balance to be recovered from ratepayers. The Parties agree that any such future debit balance in the account will be accepted by them, subject to it having been accurately calculated and recorded. If required, these principles will apply to periods after December 31, 2014 until such time as new nuclear payment amounts reflecting the revised service lives are established. For greater clarity, the recordings of additions of $46.9M per year credit will continue in this account after December 31, 2014 if new nuclear payment amounts are not set at that time, until such time new ones are established reflecting the revised service lives.

By way of example for the above, should new nuclear payment amounts be set effective January 1, 2014 based on a revenue requirement that incorporates a reduction in depreciation expense and associated taxes for the 2014 year, OPG would not record a credit in the account for 2014. However, OPG would still record an amortization amount of $46.9M in the account in 2014 in order to reflect the fact that the rate riders, set in this proceeding at a lower level to reflect the 2014 credit, would continue during 2014. This would result in a debit balance in the account at the end of 2014. This balance would need to be recovered from ratepayers in order to avoid the “double-counting” of the benefit of lower depreciation and associated taxes for 2014.

Approval

Parties in Support: VECC, SEC, CCC, Energy Probe, AMPCO, CME, PWU

Parties Taking No Position: N/A

Evidence

The evidence in relation to these issues includes the following:

- H1-1-1 Overview of Deferral and Variance Accounts
- H1-1-2 Update for Audited Actual Balances for Deferral and Variance Accounts and Other Information
- H2-1-1 Nuclear Liability Deferral Account
- H2-2-1 Supporting Evidence for Entries into Nuclear Accounts
- L-1-1 Staff-02 Board Staff IR #2

- L-1-1 Staff-03 Board Staff IR #3
- L-1-6 PWU-01 PWU IR #1
- L-1-7 SEC-02 SEC IR #2
- L-2-1 Staff-19 Board Staff IR #19
- L-2-2 AMPCO-10 AMPCO IR #10

ATTACHMENTS

Attachment 1

Copies of Ex. H1-1-2, Tables 16 and 17, which show calculation of Deferral and Variance Account Recovery payment Rides for regulated hydroelectric and nuclear, respectively, and recasts of those tables, labeled Tables 16A and 17A, which show amounts and riders resulting from this agreement. This attachment also contains a recast of Ex. H1-1-2 Table 23, labeled Table 23A, showing calculation of Interim Period Shortfall Riders resulting from this agreement. This attachment also contains a table labeled Table 17B which shows the amortization pattern resulting from the 60/40 weighting described in section B3.

Numbers may not add due to rounding.

Table 16
(Updated version of Ex. H1-2-1 Table 1 - Originally filed 2013-02-08 as Ex. H1-1-2 Table 16)
Calculation of Deferral and Variance Account Recovery Payment Rider - Regulated Hydroelectric ($M)

Line No.	Account	Balance at December 31, 2012[1]	Balance For Recovery[2]	Recovery Period (Months)[3]	Amortization 2013[4]	Amortization 2014[4]	(d)+(e) 2013-2014 Amortization / Rider	(a)-(f) Projected Unrecovered Balance at December 31, 2014
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Hydroelectric Water Conditions Variance**	17.1	17.1	24	8.6	8.6	17.1	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	34.0	34.0	24	17.0	17.0	34.0	0.0
3	**Hydroelectric Incentive Mechanism Variance**	(2.4)	0.0	N/A	0.0	0.0	0.0	(2.4)
4	**Hydroelectric Surplus Baseload Generation Variance**	4.1	0.0	N/A	0.0	0.0	0.0	4.1
5	**Income and Other Taxes Variance - Hydroelectric**	(2.5)	(2.5)	24	(1.3)	(1.3)	(2.5)	0.0
6	**Tax Loss Variance - Hydroelectric**	48.2	48.2	24	24.1	24.1	48.2	0.0
7	**Capacity Refurbishment Variance - Hydroelectric**	1.1	0.0	N/A	0.0	0.0	0.0	1.1
8	**Pension and OPEB Cost Variance - Hydroelectric**	15.1	15.1	48	3.8	3.8	7.6	7.6
9	**Impact for USGAAP Deferral - Hydroelectric**	2.8	2.8	24	1.4	1.4	2.8	0.0
10	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(3.9)	(3.9)	24	(1.9)	(1.9)	(3.9)	0.0
11	**Total** (lines 1 though 10)	113.8	110.9		51.7	51.7	103.3	10.5
12	**Total Approved 2011-2012 Production[5] (TWh)**						39.7	
13	**Regulated Hydroelectric Payment Rider ($/MWh)** (line 11 / line 12)						2.60	

Notes:
1 From Ex. H1-1-2 Table 1.
2 From col. (a) except for lines 3, 4 and 7. See Ex. H1-1-1 Sections 4.4 and 5.5.
3 From Ex. H1-2-1 Table 1, col. (c).
4 Col. (b) amount x 12 months / recovery period in col. (c).
5 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.

Numbers may not add due to rounding.

Table 17
(Updated version of Ex. H1-2-1 Table 2 - Originally filed 2013-02-08 as Ex. H1-1-2 Table 17)
Calculation of Deferral and Variance Account Recovery Payment Rider - Nuclear ($M)

Line No.	Account	Balance at December 31, 2012[1]	Balance For Recovery[2]	Recovery Period (Months)[3]	Amortization 2013[4]	Amortization 2014[4]	(d)+(e) 2013-2014 Amortization / Rider	(a)-(f) Projected Unrecovered Balance at December 31, 2014
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Nuclear Liability Deferral**	208.0	208.0	24	104.0	104.0	208.0	0.0
2	**Nuclear Development Variance**	30.2	30.2	24	15.1	15.1	30.2	0.0
3	**Ancillary Services Net Revenue Variance - Nuclear**	1.7	1.7	24	0.8	0.8	1.7	0.0
4	**Capacity Refurbishment Variance - Nuclear[5]**	13.1	11.8	24	5.9	5.9	11.8	1.3
5	**Bruce Lease Net Revenues Variance**	310.5	310.5	48	77.6	77.6	155.2	155.2
6	**Income and Other Taxes Variance - Nuclear**	(32.5)	(32.5)	24	(16.3)	(16.3)	(32.5)	0.0
7	**Tax Loss Variance - Nuclear**	253.3	253.3	24	126.7	126.7	253.3	0.0
8	**Pension and OPEB Cost Variance - Nuclear**	309.1	309.1	48	77.3	77.3	154.6	154.6
9	**Impact for USGAAP Deferral - Nuclear**	60.3	60.3	24	30.1	30.1	60.3	0.0
10	**Nuclear Deferral and Variance Over/Under Recovery Variance**	6.9	6.9	24	3.5	3.5	6.9	0.0
11	**Total** (lines 1 through 10)	1,160.6	1,159.2		424.7	424.7	849.4	311.1
12	**Total Approved 2011-2012 Production[6] (TWh)**						101.9	
13	**Nuclear Payment Rider ($/MWh)** (line 11 / line 12)						8.34	

Notes:
1 From Ex. H1-1-2 Table 1.
2 From col. (a) except for line 4. See Note 4.
3 From Ex. H1-2-1 Table 2, col. (c).
4 Col. (b) amount x 12 months / recovery period in col. (c).
5 Col. (b) amount excludes other additions to account in 2012 of $1.3M relating to a Darlington refurbishment capital cost variance to be cleared at a later date.
6 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.

Numbers may not add due to rounding.

Filed: 2013-03-14
EB-2012-0002
Exhibit M1-1
Attachment 1
Table 16A

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Table 16A

(Updated version of Ex. H1-2-1 Table 1)

Calculation of Deferral and Variance Account Recovery Payment Rider - Regulated Hydroelectric ($M)

Line No.	Account	Audited Balance at Dec 31 2012[1]	Negotiated Reductions	(a) + (b) Settlement Balance Dec 31 2012	Deferrals Advancements and Adjustments	(c) + (d) Settlement Balance For Recovery	Recovery Period (Months)	2013 Amortization / Rider [2]	2014 Amortization / Rider [2]	(g) + (h) 2013-2014 Amortization / Blended Rider	(c) - (i)[7] Balance Remaining at Dec 31, 2014 Including Adjustments
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Hydroelectric Water Conditions Variance**	17.1	-	17.1	-	17.1	24	8.6	8.6	17.1	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	34.0	-	34.0	-	34.0	24	17.0	17.0	34.0	0.0
3	**Hydroelectric Incentive Mechanism Variance**[3]	(2.4)	-	(2.4)	2.4	0.0	N/A	0.0	0.0	0.0	(2.4)
4	**Hydroelectric Surplus Baseload Generation Variance**[3]	4.1	-	4.1	(4.1)	0.0	N/A	0.0	0.0	0.0	4.1
5	**Income and Other Taxes Variance - Hydroelectric**	(2.5)	-	(2.5)	-	(2.5)	24	(1.3)	(1.3)	(2.5)	0.0
6	**Tax Loss Variance - Hydroelectric**	48.2	-	48.2	-	48.2	24	24.1	24.1	48.2	0.0
7	**Capacity Refurbishment Variance - Hydroelectric**[3]	1.1	-	1.1	(1.1)	0.0	N/A	0.0	0.0	0.0	1.1
8	**Pension and OPEB Cost Variance - Hydroelectric**[4]	15.1	-	15.1	0.04	15.2	See note 6	2.3	2.3	4.7	10.5
9	**Impact for USGAAP Deferral - Hydroelectric**	2.8	-	2.8	-	2.8	24	1.4	1.4	2.8	0.0
10	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(3.9)	-	(3.9)	-	(3.9)	24	(1.9)	(1.9)	(3.9)	0.0
11	**Total** (lines 1 though 10)	113.8	-	113.8	(2.9)	111.0		50.2	50.2	100.4	13.4
	60 / 40 Split 2013/2014 (col. (g) = col. (i) x 60%; col. (h) = col. (i) x 40%)							**60.3**	**40.2**	100.4	
12	**Total Approved 2011-2012 Production[5] (TWh)**							**19.9**	**19.9**	39.7	
13	**Regulated Hydroelectric Payment Rider ($/MWh)** (line 11 / line 12)							**3.04**	**2.02**	2.53	

Notes:

1 From Ex. H1-1-2 Table 1.

2 Col. (e) amount x 12 months / recovery period in col. (f), except line 8. See note 6.

3 Deferred per original application.

4 Col. (d) adds interest on the 2/12 amount per M1-1 Section B3.

5 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.

6 Amortization calculated as described in Ex. M1-1 Section B3.

7 Except for row 8, where col. (j) = col. (e) - col. (i).

Numbers may not add due to rounding.

Filed: 2013-03-14
EB-2012-0002
Exhibit M1-1
Attachment 1
Table 17A

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Table 17A

(Recast version of Ex. H1-1-2 Table 17)

Calculation of Deferral and Variance Account Recovery Payment Rider - Nuclear ($M)

Line No.	Account	Audited Balance at 31-Dec 2012[1]	Negotiated Reductions	(a) + (b) Settlement Balance 31-Dec 2012	Deferrals, Advancements and Adjustments	(c) + (d) Settlement Balance For Recovery	Recovery Period (Months)	2013 Amortization / Rider [2]	2014 Amortization / Rider [2]	(g)+(h) 2013-2014 Amortization / Blended Rider	(c)-(i)[12] Balance Remaining at Dec 31, 2014 Including Adjustments
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Nuclear Liability Deferral [3]**	208.0	(1.8)	206.2	(81.4)	124.8	24	62.4	62.4	124.8	81.4
2	**Nuclear Development Variance [4]**	30.2	-	30.2	(30.2)	0.0	24	0.0	0.0	0.0	30.2
3	**Ancillary Services Net Revenue Variance - Nuclear**	1.7	-	1.7	-	1.7	24	0.8	0.8	1.7	0.0
4	**Capacity Refurbishment Variance - Nuclear [5]**	13.1	-	13.1	(1.3)	11.8	24	5.9	5.9	11.8	1.3
5	**Bruce Lease Net Revenues Variance - Derivative Portion**	230.3	-	230.3	-	230.3	See note 6	5.3	62.2	67.5	162.8
5a	**Bruce Lease Net Revenues Variance - Non-derivative Portion [7]**	80.2	(5.5)	74.8	-	74.8	48	18.7	18.7	37.4	37.4
6	**Income and Other Taxes Variance - Nuclear**	(32.5)	-	(32.5)	-	(32.5)	24	(16.3)	(16.3)	(32.5)	0.0
7	**Tax Loss Variance - Nuclear**	253.3	-	253.3	-	253.3	24	126.7	126.7	253.3	0.0
8	**Pension and OPEB Cost Variance - Nuclear [8]**	309.1	-	309.1	0.8	309.9	See note 9	47.6	47.6	95.2	214.7
9	**Impact for USGAAP Deferral - Nuclear**	60.3	-	60.3	-	60.3	24	30.1	30.1	60.3	0.0
10	**Nuclear Deferral and Variance Over/Under Recovery Variance**	6.9	-	6.9	-	6.9	24	3.5	3.5	6.9	0.0
10a	**Pickering Life Extension Depreciation Account [10]**	N/A	N/A	N/A	(93.8)	(93.8)	See note 10	(46.9)	(46.9)	(93.8)	0.0
11	**Total** (lines 1 through 10a)	1,160.6	(7.3)	1,153.3	(206.0)	947.3		237.8	294.7	532.5	527.8
11a	**60 / 40 Split 2013/2014** (col. (g) = col. (i) x 60%; col. (h) = col. (i) x 40%)							**319.5**	**213.0**	532.5	
12	**Total Approved 2011-2012 Production [11] (TWh)**							**51.0**	**51.0**	101.9	
13	**Nuclear Payment Rider ($/MWh)** (line 11a / line 12)							**6.27**	**4.18**	5.23	

Notes:

1 Ex. H1-1-2 Table 1, except lines 5 and 5a. Line 5 is the sum of the amounts on line 8 of Ex. M1-1, Attachment 2, Table 14. Line 5a is the sum of the amounts on line 9 of Ex. M1-1, Attachment 2, Table 14 plus interest on the total balance in the Bruce Lease Net Revenues Variance Account, from Ex. H1-1-2 Tables 1a, 1b and 1c, line 20.

2 Col. (e) amount x 12 months / recovery period in col. (f), except line 5. See Note 6.

3 Adjustment in col. (b) is $1.8M in foregone interest as described in Ex. M1-1 Section B1. Adjustment in col. (d) is $81.4M credit for accounting changes for station service lives as described in Ex. M1-1 Section B3 and shown at Ex. M1-1, Attachment 3, Table 1, line 17b.

4 Balance in account to be held over for disposition in a future proceeding.

5 Portion deferred per original application.

6 Amortization calculated as described in Ex. M1-1 Section B3, and shown in cols. (g) and (h) is from Ex. M1-1, Attachment 2, Table 14c, lines 15 and 16, respectively.

7 Col. (b) removes interest on the total balance in the Bruce Lease Net Revenues Variance Account, from Ex. H1-1-2 Tables 1a, 1b and 1c, line 20.

8 Col. (d) adds interest on the 2/12 amount per M1-1 Section B3.

9 Amortization calculated as described in Ex. M1-1 Section B3.

10 As described in Ex. M1-1 Section D. The $46.9M / year adjustment is shown at Attachment 3, Table 1, line 17a.

11 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.

12 Except for rows 8 and 10a, where col. (j) = col. (e) - col. (i).

Numbers may not add due to rounding.

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Exhibit M1-1
Attachment 1
Table 17B

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Table 17B

Amortization Pattern Under 60 / 40 Weighting

Line No.	Account	Unadjusted Amortization Pattern from M1-1 Attachment 1 Tables 16A and 17A, Columns (g) and (h)			Amortization Pattern Adjusted for Weighting 60% 2013 / 40% 2014		
		2013 Amortization	2014 Amortization	(a)+(b) 2013-2014 Amortization	(c) x 60% 2013 Amortization	(c) x 40% 2014 Amortization	(d) + (e) 2013-2014 Amortization
		(a)	(b)	(c)	(d)	(e)	(f)
	Regulated Hydroelectric Accounts						
1	**Hydroelectric Water Conditions Variance**	8.6	8.6	17.1	10.3	6.8	17.1
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	17.0	17.0	34.0	20.4	13.6	34.0
3	**Hydroelectric Incentive Mechanism Variance**	0.0	0.0	0.0	0.0	0.0	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**	0.0	0.0	0.0	0.0	0.0	0.0
5	**Income and Other Taxes Variance - Hydroelectric**	(1.3)	(1.3)	(2.5)	(1.5)	(1.0)	(2.5)
6	**Tax Loss Variance - Hydroelectric**	24.1	24.1	48.2	28.9	19.3	48.2
7	**Capacity Refurbishment Variance - Hydroelectric**	0.0	0.0	0.0	0.0	0.0	0.0
8	**Pension and OPEB Cost Variance - Hydroelectric**	2.3	2.3	4.7	2.8	1.9	4.7
9	**Impact for USGAAP Deferral - Hydroelectric**	1.4	1.4	2.8	1.7	1.1	2.8
10	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(1.9)	(1.9)	(3.9)	(2.3)	(1.5)	(3.9)
11	**Sub Total - Regulated Hydroelectric** (lines 1 through 10)	50.2	50.2	100.4	60.3	40.2	100.4
	Nuclear Accounts						
12	**Nuclear Liability Deferral**	62.4	62.4	124.8	74.9	49.9	124.8
13	**Nuclear Development Variance**	0.0	0.0	0.0	0.0	0.0	0.0
14	**Ancillary Services Net Revenue Variance - Nuclear**	0.8	0.8	1.7	1.0	0.7	1.7
15	**Capacity Refurbishment Variance - Nuclear**	5.9	5.9	11.8	7.1	4.7	11.8
16	**Bruce Lease Net Revenues Variance - Derivative Portion**	5.3	62.2	67.5	40.5	27.0	67.5
17	**Bruce Lease Net Revenues Variance - Non-derivative Portion**	18.7	18.7	37.4	22.4	15.0	37.4
18	**Income and Other Taxes Variance - Nuclear**	(16.3)	(16.3)	(32.5)	(19.5)	(13.0)	(32.5)
19	**Tax Loss Variance - Nuclear**	126.7	126.7	253.3	152.0	101.3	253.3
20	**Pension and OPEB Cost Variance - Nuclear**	47.6	47.6	95.2	57.1	38.1	95.2
21	**Impact for USGAAP Deferral - Nuclear**	30.1	30.1	60.3	36.2	24.1	60.3
22	**Nuclear Deferral and Variance Over/Under Recovery Variance**	3.5	3.5	6.9	4.2	2.8	6.9
23	**Pickering Life Extension Plant Depreciation Account**	(46.9)	(46.9)	(93.8)	(56.3)	(37.5)	(93.8)
24	**Sub Total - Nuclear** (lines 12 through 23)	237.8	294.7	532.5	319.5	213.0	532.5
25	**Total** (line 11 + line 24)	288.0	344.9	632.9	379.8	253.2	632.9

Settlement Agreement
Table 23A
(Recast version of Ex. H1-1-2 Table 23)
Calculation of Interim Period Shortfall Riders

Line No.	Account	March 1, 2013 Implementation		April 1, 2013 Implementation	
		Regulated Hydroelectric	Nuclear	Regulated Hydroelectric	Nuclear
		(a)	(b)	(c)	(d)
1	**Approved Rider ($/MWh)**[1]	3.04	6.27	3.04	6.27
2	**Interim Rider ($/MWh)**[2]	0.0	4.33	0.0	4.33
3	**2011/2012 Average January Production Forecast (TWh)**[3]	1.6	4.8	1.6	4.8
4	**2011/2012 Average February Production Forecast (TWh)**[3]	1.5	4.2	1.5	4.2
5	**2011/2012 Average March Production Forecast (TWh)**[3]			1.7	4.3
6	**Interim Period Production Forecast (TWh)**	3.2	9.0	4.9	13.2
	(line 5 + line 6 for March 1 implementation)				
	(line 5 + line 6 + line 7 for April 1 implementation)				
7	**Production Forecast Used to Set Proposed Rider (TWh)**[4]	19.9	51.0	19.9	51.0
8	**Interim Period Shortfall Rider ($/MWh)** (((line 1 - line 2) x line 6) / (line 7 - line 6))	0.58	0.41	1.00	0.68

Notes:
1 2013 rider proposed for approval in this Settlement Agreement.
Regulated Hydroelectric from Ex. M1-1, Attachment 1, Table 16A, line 13. Nuclear from Ex. M1-1, Attachment 1, Table 17A, line 13.
2 Per EB-2012-0002 Procedural Order No. 1.
3 Based on average of 2011 and 2012 production for the given month, from monthly production figures provided in L-2-1 Staff-16, Attachment 1, Table 2 (Regulated Hydroelectric) and Table 3 (Nuclear).
4 Regulated Hydroelectric from Ex. M1-1, Attachment 1, Table 16A, line 12. Nuclear from Ex. M1-1, Attachment 1, Table 17A, line 12.

Attachment 2

Recasts of Ex. H1-1-2, Tables 14, 14a and a new Table 14c, which show amounts related to the Bruce Lease Net Revenues Variance Account split between derivative and non-derivative portions as set out in this agreement.

Settlement Agreement

Table 14

(Recast version of Ex. H1-1-2 Table 14)

Bruce Lease Net Revenues Variance Account[1]

Summary of Account Transactions - 2011 and 2012

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Actual 2012
		(a)	(b)	(c)
1	**Actual Total Bruce Lease Net Revenues[2] ($M)**	32.7	35.5	(117.7)
2	**Forecast Bruce Lease Net Revenues - EB-2009-0174 / EB-2010-0008[3] ($M)**	191.9	271.1	271.1
3	**Nuclear Forecast Production - EB-2009-0174 / EB-2010-0008[3] (TWh)**	88.2	101.9	101.9
4	**Rate Credited to Customers ($/MWh)** (line 2 / line 3)	2.18	2.66	2.66
5	**Actual Nuclear Production[4] (TWh)**	8.8	39.8	49.0
6	**Amount Credited to Customers ($M)** (line 4 x line 5)	19.1	105.9	130.4
7	**Total Addition to Variance Account ($M)** (line 6 - line 1)	(13.6)	70.4	248.2
8	**Less: Addition to Variance Account - Derivative Portion[5] ($M)**	3.2	14.4	212.6
9	**Addition to Variance Account - Non-derivative Portion ($M)** (line 7 - line 8)	(16.8)	56.0	35.5

Notes:

1 The variance account is discussed in Ex. H2-1-2 and Ex. H1-1-2.

2 From Ex. M1-1, Attachment 2, Table 14a, line 22.

3 In accordance with the EB-2009-0174 Decision and Order, the forecast in col. (a) is for the EB-2007-0905 21-month test period of April 1, 2008 to December 31, 2009.
Forecasts in cols. (b) and (c) are for the 24-month test period of January 1, 2011 to December 31, 2012, as reflected in the EB-2010-0008 Payment Amounts Order: line 2 is from App. A, Table 2, line 20; line 3 is from App. C, Table 1, line 2.

4 Amount for full year 2011 is as reported in OPG’s Management’s Discussion & Analysis for the year ended December 31, 2011 as filed with the Ontario Securities Commission, and is provided at Ex. A3-1-1, Attachment 1, page 12.

5 From Ex. M1-1, Attachment 2, Table 14a, line 23.

Settlement Agreement

Table 14a
(Recast version of Ex. H1-1-2 Table 14a)
Bruce Lease Net Revenues Variance Account
Comparison of Bruce Lease Net Revenues - 2011 and 2012 ($M)

Line No.	Particulars	Jan - Feb 2011 Actual	Mar - Dec 2011 Actual	(a) + (b) 2011 Actual	2011 Board Approved (EB-2010-0008)	(c) - (d) Change	2012 Actual	2012 Board Approved (EB-2010-0008)	(f) - (g) Change
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Revenues:								
1	**Site Services (OPG to Bruce Power)**	0.0	1.1	1.1	0.6	0.5	0.7	0.5	0.2
2	**Low & Intermediate Level Waste Services**	3.0	11.7	14.6	13.6	1.0	5.8	12.4	(6.6)
3	**Cobalt-60**	0.0	0.5	0.5	0.5	(0.0)	0.4	0.5	(0.2)
4	**Total Services**	3.0	13.2	16.2	14.7	1.5	6.8	13.4	(6.6)
5	**Fixed (Base) Rent**	6.8	34.1	40.9	40.9	0.0	40.9	40.9	(0.0)
6	**Supplemental Rent - Derivative Portion**	(4.3)	(19.2)	(23.5)	0.0	(23.5)	(283.5)	0.0	(283.5)
6a	**Supplemental Rent - Non-derivative Portion**	30.8	153.7	184.5	186.7	(2.2)	191.4	202.3	(10.9)
7	**Amortization of Initial Deferred Rent**	2.0	10.1	12.1	12.1	0.0	12.1	12.1	(0.0)
8	**Total Rent**	35.3	178.7	214.0	239.8	(25.7)	(39.1)	255.3	(294.4)
9	**Total Revenues**	38.3	191.9	230.2	254.4	(24.2)	(32.3)	268.7	(301.0)
	Costs:								
10	**Depreciation**	6.0	27.2	33.2	34.5	(1.3)	78.9	34.5	44.4
11	**Property Tax**	2.1	10.1	12.2	13.6	(1.4)	11.4	14.1	(2.6)
12	**Capital Tax**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**Accretion**[1]	49.6	247.0	296.6	294.5	2.1	327.8	307.2	20.6
14	**(Earnings) Losses on Segregated Funds**[1]	(68.0)	(172.1)	(240.1)	(286.2)	46.1	(350.9)	(304.6)	(46.3)
15	**Used Fuel Storage and Disposal**[1]	3.0	24.0	27.0	17.0	10.1	44.5	24.0	20.5
16	**Waste Management Variable Expenses**[2]	0.2	0.8	1.0	0.8	0.1	2.9	0.7	2.2
17	**Interest**	2.2	9.4	11.6	11.9	(0.3)	14.7	6.9	7.8
18	**Total Costs Before Income Tax**	(4.9)	146.5	141.6	86.1	55.5	129.4	82.8	46.6
19	**Income Tax - Current - Derivative Portion**[3]	0.0	0.0	0.0	0.0	0.0	(11.7)	0.0	(11.7)
19a	**Income Tax - Current - Non-derivative Portion**[4]	0.0	0.0	0.0	0.0	0.0	11.7	8.6	3.0
20	**Income Tax - Future - Derivative Portion**[3]	(1.1)	(4.8)	(5.9)	0.0	(5.9)	(59.2)	0.0	(59.2)
20a	**Income Tax - Future Non-derivative Portion**[5]	11.6	14.6	26.2	40.2	(14.0)	15.2	34.3	(19.1)
21	**Total Costs**	5.6	156.4	161.9	126.3	35.6	85.5	125.7	(40.3)
22	**Total Bruce Lease Net Revenues** (line 9 - line 21)	32.7	35.5	68.2	128.1	(59.8)	(117.7)	143.0	(260.8)
23	**Bruce Lease Net Revenues - Derivative Portion** (line 6 - line 19 - line 20)	(3.2)	(14.4)	(17.6)	0.0	(17.6)	(212.6)	0.0	(212.6)
24	**Bruce Lease Net Revenues - Non-derivative Portion** (line 22 - line 23)	35.9	49.9	85.9	128.1	(42.2)	94.9	143.0	(48.1)

Notes:

1 Amounts in cols. (c) and (f) are from Ex. H1-1-2 Table 19, cols. (b) and (c) respectively.

2 Amount in col. (c) is from Ex. H1-1-2 Table 19, line 5, col. (b). Amount in col. (f) is the sum of $1.8M for ongoing waste management variable expenses from Ex. H1-1-2 Table 19, line 5, col. (c) and $1.1M for expenses resulting from the implementation of new CNSC requirements in 2012 per note 4 in Ex. H1-1-2 Table 19.

3 The total of amounts in each of cols. (c) and (f) is the sum of the following income tax impacts related to the embedded derivative (all references to Ex. H1-1-2 Table 14b cols. (a) and (b), respectively): (i) line 15 x line 21 or line 30 for the impact related to changes in taxable income/tax loss; and (ii) (line 15 - line 7) x line 27 for the portion of the impact related to changes in net temporary differences.

4 Amounts in cols. (c) and (f) represent the difference between income tax amounts related to total Bruce Lease net revenues from Ex. H1-1-2 Table 14b, line 22, cols. (a) and (b), respectively, and those at Ex. M1-1, Attachment 2, Table 14a, line 19 in cols. (c) and (f), respectively, related to the derivative portion of the net revenues.

5 Amounts in cols. (c) and (f) represent the difference between income tax amounts at Ex. H1-1-2 Table 14b, line 32, cols. (a) and (b), respectively, related to total Bruce Lease net revenues and those at Ex. M1-1, Attachment 2, Table 14a, line 20 in cols. (c) and (f), respectively, related to the derivative portion of the net revenues.

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Table 14c

Balance for Recovery of Derivative Portion of Bruce Lease Net Revenues Variance Account ($M)

As at December 31, 2012

Line No.	Particulars	Amount at Dec. 31, 2012
		(a)
	Amount for Recovery in 2013 and 2014 Before Prior Recovery Adjustment	
	2012:	
1	**Actual Supplemental Rent Payment Reduction (Partial Rebate)**[1]	77.9
2	**Less: Income Tax Impact**[2] (line 1 x 2012 tax rate of 25%)	19.5
3	**Net Rent Payment Reduction**	58.4
	2013:	
4	**Estimated Supplemental Rent Payment Reduction (Partial Rebate)**[3]	80.3
5	**Less: Income Tax Impact**[2] (line 4 x expected 2013 tax rate of 25%)	20.1
6	**Net Rent Payment Reduction**	60.2
	2014:	
7	**Estimated Supplemental Rent Payment Reduction (Partial Rebate)**[3]	82.9
8	**Less: Income Tax Impact**[2] (line 7 x expected 2014 tax rate of 25%)	20.7
9	**Net Rent Payment Reduction**	62.2
10	**Total Amount for Recovery in 2013 and 2014 Before Prior Recovery Adjustment**	180.8
	(line 3 + line 6 + line 9)	
	Prior Recovery Adjustment	
11	**EB-2010-0008 Approved Account Balance at Dec. 31, 2010 - Derivative Portion of Additions**[4]	161.2
12	**Less: 2009 Actual Supplemental Payment Reduction (Partial Rebate)**[5]	69.4
13	**Add: Income Tax Impact of 2009 Rebate** (line 11 x 2009 tax rate of 31%)	21.5
14	**Prior Recovery Adjustment**	113.4
	Amount for Recovery in 2013 and 2014 After Prior Recovery Adjustment	
15	**2013 Amortization of December 31, 2012 Account Balance** (line 3 + line 6 - line 14)	5.3
16	**2014 Amortization of December 31, 2012 Account Balance** (line 9)	62.2
17	**Total Amount for Recovery in 2013 and 2014**	67.5

Notes:

1 From Ex. H1-1-2 Table 14b, col. (b), line 15 and as discussed in Ex. H1-1-2, section 3.3.1.1.

2 Represents income tax impact of the reduction in taxable income (or increase in tax loss) arising from the supplemental rent payment reduction.

3 From Ex. H1-1-2 Attachment 4, page 1, line "Full Rent Rebate".

4 The derivative portion of account additions in the EB-2010-0008 approved December 31, 2010 balance in the Bruce Lease Net Revenues Variance Account is calculated as follows:

Line No.		Year Ended Dec. 31, 2009	Year Ended Dec. 31, 2010	Total at Dec. 31, 2010
		(a)	(b)	(c)
1a	Supplemental Rent Revenue - Derivative Portion[#]	187.4	45.0	232.4
2a	Less: Income Tax Impact (line 1a x tax rate of 31% for 2009, 29% for 2010)	58.1	13.1	71.1
3a	Derivative Portion of Account Additions (line 1a - line 2a)	129.3	32.0	161.2

2009 amount consists of reductions to revenue of $69.4M for the 2009 rent rebate (from line 12 above) and $118.0M for the increase in the fair value of the Bruce Lease embedded derivative during 2009 (EB-2010-0008, Ex. G2-2-1, section 4.5).

5 As discussed in EB-2010-0008, Ex. G2-2-1, section 4.5.

Attachment 3

Table 1, showing the projected revenue requirement impact of Pickering and Bruce accounting service life changes and supporting tables, Table 1a and 2.

Numbers may not add due to rounding.

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Table 1

Projected Revenue Requirement Impact of Pickering and Bruce Accounting Service Life Changes ($M)

Year Ending December 31, 2013

Line No.	Description	Projected Revenue Requirement Impact
		(a)
	PRESCRIBED FACILITIES	
	Return on Rate Base:	
1	**Accretion Rate on Lesser of ARC and UNL** (from Ex. M1-1, Att. 3, Table 1a, note 1, col. (c), line 3a)	(14.6)
2	**Non-ARC Rate Base** (refer to Ex. M1-1, Att. 3, Table 1a, note 2)	1.2
3	**Total Return on Rate Base Impact**	(13.4)
	Depreciation Expense:	
4	**Asset Retirement Costs** (from Ex. M1-1, Att. 3, Table 2, col. (c), line 18)	(46.5)
5	**Non-Asset Retirement Costs** (from Ex. M1-1, Att. 3, Table 1a, note 3, col. (d), line 10a)	(35.2)
6	**Total Depreciation Expense Impact**	(81.6)
	Other Expenses:	
7	**Used Fuel Storage and Disposal Variable Expenses** (from Ex. M1-1, Att. 3, Table 2, col. (c), line 2)	(1.2)
8	**Low & Intermediate Level Waste Management Variable Expenses** (from Ex. M1-1, Att. 3, Table 2, col. (c), line 3)	(0.0)
9	**Total Other Expenses Impact**	(1.2)
	Income Taxes: (refer to Ex. M1-1, Att. 3, Table 1a, note 4)	
10	**Accretion Rate on Lesser of ARC and UNL**	(4.9)
11	**Return on Rate Base - Non-ARC Impact**	0.4
12	**Depreciation Expense on Asset Retirement Costs**	(15.5)
13	**Depreciation Expense on Non-Asset Retirement Costs**	(11.7)
14	**Used Fuel Storage and Disposal Variable Expenses**	(0.4)
15	**Low & Intermediate Level Waste Management Variable Expenses**	(0.0)
16	**Total Income Tax Impact**	(32.1)
17	**Total Projected Revenue Requirement Impact - Prescribed Facilities** (line 3 + line 6 + line 9 + line 16)	(128.3)
17a	**Projected Revenue Requirement Impact of Non-ARC Depreciation - Prescribed Facilities** (line 5 + line 13)	(46.9)
17b	**Projected Revenue Requirement Impact Excluding Non-ARC Depreciation - Prescribed Facilities** (line 17 + line 17a)	(81.4)
	BRUCE FACILITIES	
	Depreciation Expense:	
18	**Asset Retirement Costs**	28.2
19	**Non-Asset Retirement Costs**	(7.2)
20	**Total Depreciation Expense Impact**	21.0
	Other Expenses:	
21	**Accretion**	24.7
22	**Used Fuel Storage and Disposal Variable Expenses**	(1.1)
23	**Low & Intermediate Level Waste Management Variable Expenses**	(0.0)
24	**Total Other Expenses Impact**	23.6
	Income Taxes:	
25	**Impact on Bruce Facilities' Income Tax Calculation**	(11.1)
26	**Impact on Prescribed Facilities' Income Tax Calculation**	11.1
27	**Total Income Tax Impact**	0.0
28	**Total Projected Revenue Requirement Impact - Bruce Facilities**	44.6
	(line 20 + line 24 + line 27)	
29	**Total Projected Revenue Requirement Impact**	(83.7)
	(line 17 + line 28)	

See Ex. M1-1, Attachment 3, Table 1a for notes.

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Table 1a

Projected Revenue Requirement Impact of Pickering and Bruce Accounting Service Life Changes ($M)

Year Ending December 31, 2013

Notes to Ex. M1-1, Attachment 3, Table 1

Notes:

1 The full amount of the projected average asset retirement costs ("ARC") would earn a return at the weighted average accretion rate under both scenarios of "with" and "without" Pickering and Bruce accounting service life changes effective December 31, 2012, as the projected average ARC is lesser than the projected average unfunded nuclear liability ("UNL") for 2013 in both scenarios, as shown at line 21 of Ex. M1-1, Att. 3, Table 2. Specifically, the impact on the return amount is calculated as follows:

Table to Note 1

Line No.	Description	With Service Life Changes	Without Service Life Changes	(a)-(b) Difference
		(a)	(b)	(c)
1a	2013 Projected Average ARC (from Ex. M1-1, Att. 3, Table 2, line 21)	1,470.2	1,723.9	(253.7)
2a	Weighted Average Accretion Rate#	5.37%	5.43%	
3a	Return on Rate Base (for cols. (a) and (b), line 1a x line 2a)	78.9	93.6	(14.6)

\# The "without service life changes" weighted average accretion rate of 5.43% is as calculated in EB-2012-0002, L-1-7 SEC-11. (December 31, 2021 for Pickering A; September 30, 2014 for Pickering B; December 31, 2051 for Darlington). The "with service life changes" weighted average accretion rate has been calculated in the same manner, as follows:

Table to Note # - Calculation of Year-End 2012 Weighted Average Accretion Rate

Line No.	Asset Retirement Obligation Tranche	Amount of Liabilities at Dec. 31, 2012 ($M)*	Weighting	Accretion Accretion Rate**	(b) x (c) Weighted Average Accretion Rate
		(a)	(b)	(c)	(d)
1a	Tranche prior to December 31, 2006	11,584.4	76.4%	5.75%	4.40%
2a	Tranche recoded on December 31, 2006 arising from the approved 2006 ONFA Reference Plan	1,726.5	11.4%	4.60%	0.52%
3a	Tranche recorded on January 1, 2010 in relation to the decision related to Darlington Refurbishment project	398.6	2.6%	4.80%	0.13%
4a	Tranche recorded on December 31, 2011 arising from the approved 2012 ONFA Reference Plan	994.0	6.6%	3.43%	0.22%
5a	Tranche recorded on December 31, 2012 arising from the approved 2012 ONFA Reference Plan	451.1	3.0%	3.50%	0.10%
6a	Total/ Weighted average as at December 31, 2012***	15,154.5	100.0%	N/A	5.37%

* The December 31, 2012 amounts for the tranches in existence prior to December 31, 2012 are different from those in EB-2012-0002, L-1-7 SEC-11, Chart 2 due to the impact of accretion expense, variable expenses for used fuel storage and disposal and low and intermediate level waste management, and expenditures against the liabilities during 2012.

** Accretion rates for the first four tranches are as shown in EB-2012-0002, L-1-7 SEC-11. Accretion rate of 3.50% for the fifth tranche, which was recorded at December 31, 2012, is as noted in EB-2012-0002, Ex. H1-1-2, section 3.3.2.

*** Represents OPG's total Nuclear Liabilities excluding consolidation adjustments

2 Non-ARC rate base would be higher due to a lower depreciation expense as shown at line 5. Therefore, the cost of capital impact shown is calculated as -(line 5 / 2) x 7.40%. Line 5 is divided by 2 to reflect the mid-year average methodology for determining rate base. The rate of 7.40% used to estimate the impact is the weighted average cost of capital for 2012, from the EB-2010-0008 Payment Amounts Order, Appendix A, Table 5b, line 6, col. (c).

3 The decrease in the 2013 projected non-ARC depreciation of $35.2M is estimated as the difference between:
(i) the total estimated decrease in both non-ARC and ARC depreciation, excluding the year-end 2012 ARC adjustment, and
(ii) the estimated decrease in ARC depreciation excluding the year-end 2012 ARC adjustment.
The $35.2M difference is calculated as follows:

Table to Note 3 - Projected 2013 ARC Depreciation Expense Excluding Year-End 2012 ARC Adjustment ($M)

Line No.		Pickering A	Pickering B	Darlington	(a)+(b)+(c) Total
		(a)	(b)	(c)	(d)
	Estimated Decrease in 2013 Total Depreciation Excluding Year-end 2012 ARC Adjustment:				
1a	Decrease in Depreciation Due to Extension of the Pickering B Service Life+	0.0	(84.6)	0.0	(84.6)
2a	Increase in Depreciation Due to Decrease in the Pickering A Service Life+	13.1	0.0	0.0	13.1
3a	Net Decrease in 2013 Total Depreciation Excluding Year-end 2012 ARC Adj.	13.1	(84.6)	0.0	(71.6)
4a	ARC as at January 1, 2013 Excluding Year-End 2012 Adjustment++	347.1	94.8	1,345.5	1,787.4
	Estimated 2013 ARC Depreciation Excluding Year-end 2012 ARC Adjustment Without Service Life Changes:				
5a	Remaining Useful Life as at December 31, 2012 (months)+++	108	21	468	
6a	Annual ARC Depreciation (line 4a / line 5a x 12 for cols. (a) through (c))	38.6	54.2	34.5	127.2
	Estimated 2013 ARC Depreciation Excluding Year-end 2012 ARC Adjustment With Service Life Changes:				
7a	Remaining Useful Life as at December 31, 2012 (months)++++	96	88	468	
8a	Annual Depreciation (line 4a / line 7a x 12 for cols. (a) through (c))	43.4	12.9	34.5	90.8
9a	Decrease in ARC Depreciation Excl. Year-End 2012 ARC Adj. (line 8a - line 6a)	4.8	(41.2)	0.0	(36.4)
10a	Estimated Decrease in 2013 Non-ARC Depreciation (line 3a - line 9a)	8.2	(43.4)	0.0	(35.2)

\+ As per OPG's approved 2012 Depreciation Review Recommendations (p. 4 of Att. 1 to Ex-2012-0002, L-2-2 AMPCO-06), which cites rounded corresponding amounts of $85M and $13M.

++ Amount in col. (d) from Ex. M1-1, Att. 3, Table 2, col. (b), line 17.

+++ Represents the service lives, for accounting purposes, of the nuclear stations as at December 31, 2012 assuming no service life changes (December 31, 2021 for Pickering A; September 30, 2014 for Pickering B; December 31, 2051 for Darlington).

++++ Represents the service lives, for accounting purposes, of the nuclear stations as at December 31, 2012 following the service life changes (December 31, 2020 for Pickering A; April 30, 2020 for Pickering B; December 31, 2051 for Darlington).

4 Tax amounts at lines 10, 11, 12, 13, 14 and 15 relate to impact items at lines 1, 2, 4, 5, 7 and 8, respectively, and are calculated by multiplying the corresponding items by t / (1-t) where t is the 2013 income tax rate of 25%. For example, line 10 = line 1 x .25 / .75 = -$14.6M x .25 / .75 = -$4.9M.

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Table 2

Prescribed Facilities - Asset Retirement Obligation, Nuclear Segregated Funds and Asset Retirement Costs ($M)

Year Ending December 31, 2013

Line No.	Description	Note	2013 Projected With Service Life Changes	2013 Projected Without Service Life Changes	(a)-(b) 2013 Projected Impact of Service Life Changes
			(a)	(b)	(c)
	ASSET RETIREMENT OBLIGATION				
1	**Opening Balance**	1, 2	8,034.1	8,311.0	(276.9)
2	**Used Fuel Storage and Disposal Variable Expenses**		52.7	53.9	(1.2)
3	**Low & Intermediate Level Waste Management Variable Expenses**		3.3	3.3	(0.0)
4	**Accretion Expense**		442.1	451.8	(9.7)
5	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(131.4)	(131.4)	0.0
6	**Closing Balance** (line 1 through line 5)		8,400.8	8,688.6	(287.8)
7	**Average Asset Retirement Obligation** ((line 1 + line 6)/2)		8,217.4	8,499.8	(282.4)
	NUCLEAR SEGREGATED FUNDS BALANCE				
8	**Opening Balance**	3	6,316.5	6,316.5	0.0
9	**Earnings (Losses)**		327.5	327.5	0.0
10	**Contributions**		136.3	136.3	0.0
11	**Disbursements**		(53.1)	(53.1)	0.0
12	**Closing Balance** (line 8 through line 11)		6,727.1	6,727.1	0.0
13	**Average Nuclear Segregated Funds Balance** ((line 8 + line 12)/2)		6,521.8	6,521.8	0.0
	UNFUNDED NUCLEAR LIABILITY BALANCE (UNL)				
14	**Opening Balance** (line 1 - line 8)		1,717.6	1,994.5	(276.9)
15	**Closing Balance** (line 6 - line 12)		1,673.6	1,961.4	(287.8)
16	**Average Unfunded Nuclear Liability Balance** ((line 14 + line 15)/2)		1,695.6	1,978.0	(282.4)
	ASSET RETIREMENT COSTS (ARC)				
17	**Opening Balance**	1, 4	1,510.5	1,787.5	(276.9)
18	**Depreciation Expense**	5	(80.7)	(127.2)	46.5
19	**Closing Balance** (line 17 + line 18)		1,429.8	1,660.3	(230.5)
20	**Average Asset Retirement Costs** ((line 17 + line 19)/2)		1,470.2	1,723.9	(253.7)
21	**LESSER OF AVERAGE UNL OR ARC** (lesser of line 16 or line 20)		1,470.2	1,723.9	(253.7)

Notes:

1 Amounts at lines 1 and 17 in col. (a) are from EB-2012-0002, Ex. H1-1-2, Table 18, col. (c), lines 12 and 30, respectively.
2 Amount in col. (b) is the sum of amounts at lines 9 and 11 from EB-2012-0002, Ex. H1-1-2, Table 18, col. (c).
3 Amounts in cols. (a) and (b) are from EB-2012-0002, Ex. H1-1-2, Table 18, col. (c), line 18.
4 Amount in col. (b) is from EB-2012-0002, Ex. H1-1-2, Table 18, col. (c), line 28.
5 Amount in col. (b) is from Ex. M1-1, Att. 3, Table 1a, note 3, col. (d), line 6a.

Attachment 4

Recasts of Ex. H1-1-2, Tables 21 and 22, which show the calculation of rate and consumer impacts resulting from this agreement.

Numbers may not add due to rounding.

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Table 21
(Updated version of Ex. I1-1-2 Table 1)
Computation of Percent Change in Payment Amounts
EB-2010-0008 to EB-2012-0002

Line No.	Description	Notes	EB-2010-0008 Board Approved Payment Amounts	EB-2012-0002 Proposed Payment Amounts	Percent Change in Payment Amounts
			(a)	(b)	(c)
	PERCENT CHANGE IN PAYMENT AMOUNTS				
	AVERAGE RATE:				
1	**Regulated Hydroelectric Rate Including Rider ($/MWh)**	1	34.13	38.31	12.2%
2	**Nuclear Rate Including Rider ($/MWh)**	2	55.85	56.75	1.6%
3	**Approved 2011-12 Regulated Hydroelectric Production (TWh)**	3	39.7	39.7	
4	**Approved 2011-12 Nuclear Production (TWh)**	3	101.9	101.9	
5	**Total Approved 2011-12 Production (TWh)** (line 3 + line 4)		141.6	141.6	
6	**Regulated Hydroelectric Portion of Production-Weighted Average Rate ($/MWh)** (line 1 x line 3 / line 5)		9.57	10.74	
7	**Nuclear Portion of Production-Weighted Average Rate ($/MWh)** (line 2 x line 4 / line 5)		40.19	40.84	
8	**Total Production-Weighted Average Rate ($/MWh)** (line 6 + line 7)		49.77	51.58	
9	**OVERALL CHANGE IN PAYMENT AMOUNTS FROM EB-2010-0008 TO EB-2012-0002**				**3.6%**
	(((line 8 col. (b) - line 8 col. (a)) / line 8 col. (a))/100)				

Notes:

1 EB-2010-0008 amount from EB-2010-0008 Payment Amounts Order, Appendix B, Table 1, line 3 plus line 5.
EB-2012-0002 amount is Board approved 2011-2012 payment amount from EB-2010-0008 Payment Amounts Order, Appendix B, Table 1, line 3 plus proposed rider from Ex. M1-1 Attachment 1, Table 16A, line 13, col. (g).

2 EB-2010-0008 amount from EB-2010-0008 Payment Amounts Order, Appendix C, Table 1, line 3 plus line 5.
EB-2012-0002 amount is Board approved 2011-2012 payment amount from EB-2010-0008 Payment Amounts Order, Appendix C, Table 1, line 3 plus proposed rider from Ex. M1-1 Attachment 1, Table 17A, line 13, col. (g).

3 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.

Numbers may not add due to rounding.

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Table 22
Typical Consumer Bill Impact

Line No.	Description	Residential
1	**Typical Consumption[1] (kWh/Month)**	842
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 12)	409
3	**Typical Bill[1] ($/Month)**	116.30
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 /1000)	**0.74**
5	**Typical Bill Impact (%)** (line 4 / line 3)	**0.6%**
6	Current OPG weighted average Hydro & Nuclear Rate ($/MWh)	49.77
7	Proposed OPG weighted average Hydro & Nuclear Rate ($/MWh)	51.58
8	Change in OPG weighted average Hydro & Nuclear Rate ($/MWh) (line 7 - line 6)	1.81
9	Change in OPG weighted average Hydro & Nuclear Rate (%) (line 8 / line 6)	4%
10	Total Forecast 2013-14 Regulated Production[2] (TWh)	138.8
11	Forecast of Provincial Demand[3] (TWh)	285.6
12	OPG Proportion of Consumer Usage (line 10 / line 11)	48.6%

Notes:

1 For Residential consumers, average monthly consumption (800 kWh) and average monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills. Typical Consumption includes line losses.

2 See L-3-5 EP-02

3 Based on IESO June 2012 18 Month Outlook. As the 18 Month Outlook did not provide a demand forecast for 2014, OPG used the IESO Energy demand forecast for 2013 (142.8 TWh) and assumed the 2014 forecast to be equal to the 2013 forecast (142.8 TWh + 142.8 TWh = 285.6 TWh).