ONTARIO POWER GENERATION

Garry M. Hendel
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Ontario Regulatory Affairs

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December 18, 2014

VIA RESS AND COURIER

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-2014-0370 – Clearance of Deferral and Variance Account Balances - Application and Prefiled Evidence

Attached please find an application by Ontario Power Generation Inc. ("OPG") for an order or orders approving the disposition of the balances as of December 31, 2014 in its deferral and variance accounts. I am providing twelve (12) paper copies of OPG's prefiled evidence.

OPG is also submitting this application on the Regulatory Electronic Submission System ("RESS"). This material will be available on OPG's website at http://www.opg.com in due course.

Regarding Notice publication, OPG notes that in its previous application to clear deferral and variance accounts (EB-2012-0002) OPG was directed to serve its application on specific interested parties, to publish the Notice in five publications, and to make its materials available at its offices and on its website. This followed on the use of a similar approach in Hydro One's application for transmission rates in EB-2012-0031. To limit costs and effort and to increase efficiency, OPG respectfully requests that the OEB consider using this approach in this application.

Regards,

[Original signed by]

Garry M. Hendel

c:	Charles Keizer (Tory's)	via email (no attachments)
	Carlton Mathias	via email (no attachments)

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ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998;*

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. for an order or orders approving the disposition of the balances as of December 31, 2014 in its deferral and variance accounts.

APPLICATION

1. The applicant, Ontario Power Generation Inc. ("OPG") is a corporation, incorporated under the Ontario *Business Corporations Act*, with its head office in the City of Toronto. The principal business of OPG is the generation and sale of electricity in Ontario.

2. In this Application, OPG applies to the Ontario Energy Board ("OEB") pursuant to section 78.1 of the *Ontario Energy Board Act, 1998*, for an order or orders approving the disposition of the balances as of December 31, 2014 in its deferral and variance accounts. To clear the account balances, OPG seeks separate payment riders for the nuclear and regulated hydroelectric accounts for the generating facilities prescribed under Ontario Regulation 53/05 ("O. Reg. 53/05"), as amended, of the Act.

3. OPG proposes that for accounts other than the Pension and OPEB Cost Variance Account and the Bruce Lease Net Revenues Variance Account, clearance of the account balances would occur over an 18-month period from July 1, 2015 through December 31, 2016.

4. For the Pension and OPEB Cost Variance Account, OPG proposes to continue to dispose of the remaining portion of the December 31, 2012 balances as per the terms of the OEB-approved settlement in EB-2012-0002. For amounts in the Pension and OPEB Cost Variance Account that have accrued since December 31, 2012, OPG proposes to clear these balances over a 24-month period from July 1, 2015 to June 30, 2017.

5. For the Bruce Lease Net Revenues Variance Account – Derivative Sub-Account, OPG proposes to clear the balance using the method as per the terms of the OEB-approved settlement in EB-2012-0002.

6. To achieve the requested disposition of the balances in the deferral and variance accounts (as described in paragraphs 2 and 3 above), OPG is seeking payment riders of $3.78/MWh and $15.78/MWh for the output of its prescribed Hydroelectric and Nuclear facilities, respectively, effective July 1, 2015.

7. The Application will be supported by written evidence. The written evidence filed by OPG may be supplemented or amended from time to time by OPG prior to the OEB's final decision on the Application.

8. OPG requests that pursuant to section 32.01 of the OEB Rules of Practice and Procedure, this proceeding be conducted by way of a written hearing.

9. OPG further applies to the OEB pursuant to the provisions of the Act and the OEB Rules of Practice and Procedure for such orders and directions as may be necessary in relation to the Application and the proper conduct of this proceeding.

10. The persons affected by this Application are all electricity consumers in Ontario. It is impractical to set out the names and addresses of the consumers because they are too numerous.

11. OPG requests that copies of all documents filed with the OEB by each party to this Application along with copies of all comments filed with the OEB in accordance with Rule 9 of the OEB Rules of Practice and Procedure be served on the applicant and the applicant's counsel as follows:

(a) The applicant: Garry Hendel
Senior Manager, Regulatory Affairs
Ontario Power Generation Inc.

Mailing address: H18 G2
700 University Avenue
Toronto ON M5G 1X6

Telephone: 416-592-6054

Facsimile: 416-592-8519

Electronic mail: opgregaffairs@opg.com

(b) The applicant's Counsel: Charles Keizer
Torys LLP

Mailing address: 79 Wellington St. W.
PO Box 270
Toronto Dominion Centre
Toronto ON M5K 1N2

Telephone: 416-865-0040

Facsimile: 416-865-7380

Electronic mail: ckeizer@torys.com

(c)	The applicant's Counsel:	Carlton D. Mathias Assistant General Counsel Ontario Power Generation Inc.
	Mailing address:	H18 A24 700 University Avenue Toronto ON M5G 1X6
	Telephone:	416-592-4964
	Facsimile:	416-592-1466
	Electronic mail:	carlton.mathias@opg.com

Dated at Toronto, Ontario, this 18th day of December, 2014.

Ontario Power Generation Inc.

[Original signed by]

Charles Keizer
Torys LLP

APPROVALS

In this Application, OPG is seeking the following specific approvals:

- Approval to clear the approved balances as of December 31, 2014 in the following accounts:
  - Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts
  - Income and Other Taxes Variance Account
  - Pension and OPEB Cost Variance Account – Historic, Future and Post 2012 Additions Sub Accounts
  - Capacity Refurbishment Variance Account – Hydroelectric and Nuclear Sub-Accounts
  - Hydroelectric Water Conditions Variance Account – Previously Regulated and Newly Regulated Sub Accounts
  - Hydroelectric Incentive Mechanism Variance Account – Previously Regulated and Newly Regulated Sub Accounts
  - Hydroelectric Surplus Baseload Generation Variance Account – Previously Regulated and Newly Regulated Sub Accounts
  - Hydroelectric Deferral and Variance Over/Under Recovery Variance Account – Previously Regulated and Newly Regulated Sub Accounts
  - Nuclear Liability Deferral Account
  - Nuclear Development Variance Account
  - Bruce Lease Net Revenues Variance Account – Derivative and Non-Derivative Sub Accounts
  - Pickering Life Extension Depreciation Variance Account
  - Nuclear Deferral and Variance Over/Under Recovery Variance Account

- The approved balances for clearing are those amounts that have accrued since December 31, 2012, in respect of those accounts for which there was balance approved by the OEB for clearance in EB-2012-0002, and since December 31, 2013, in respect of those accounts for which there was a balance approved by the OEB for clearance in EB-2013-0321.

- Approval to clear the approved balances in the above referenced accounts, except for the post 2012 additions to the Pension and OPEB Cost Variance Account and the derivative portion of the Bruce Lease Net Revenues Variance Account, over 18 months (July 1, 2015 through December 31, 2016).

- Approval to clear the approved balance in the Pension and OPEB Cost Variance Account attributable to the 2013 and 2014 Additions over 24 months (July 1, 2015 through June 30, 2017).

- Approval to clear the Bruce Lease Net Revenues Variance Account – Derivative Sub Account over 18 months (July 1, 2015 through December 31, 2016) using the method which was approved in EB-2012-0002. That method requires the amount cleared each year to be equal to the amount of the supplemental rent rebate forecast to be payable to Bruce Power for that year by OPG and associated income tax impacts, less the difference between amounts previously recovered in respect of this sub-account and actual rent rebates paid to Bruce Power by OPG and associated income taxes.

- Approval of the following payment riders effective July 1, 2015 through December 31, 2016: Regulated Hydroelectric $3.78/MWh and Nuclear $15.78/MWh.

DRAFT ISSUES LIST

The following is the draft issues list proposed by OPG.

1. Are the amounts recorded in the deferral and variance accounts appropriate?

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

3. Are the proposed rate riders and disposition periods for the account balances appropriate?

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

STAKEHOLDER INFORMATION SESSION

1.0 PURPOSE

This evidence provides a description of the stakeholder information session that OPG held on its Deferral and Variance Account Application prior to filing it with the OEB.

2.0 BACKGROUND

In advance of its application for payment riders to clear the audited December 31, 2014 balances in the deferral and variance accounts and certain associated matters, OPG held a stakeholder information session on upcoming OEB applications. The following provides an outline of the session including the objective, process, participants, and participant funding guidelines.

3.0 OBJECTIVE

The objective of the information session was to inform stakeholders about this application.

4.0 PROCESS

OPG held the stakeholder information session on a non-confidential, without-prejudice basis. Mr. Steve Klein of OPTIMUS | SBR was retained as a neutral, third-party facilitator and to document and report on the session.

The session provided an overview of the Application.

OPG invited stakeholders who participated in the last OEB proceeding regarding OPG's payment amounts, and other stakeholders who, in OPG's view, may have a material interest in the Application.

The stakeholder invitation letter which included session agenda and funding guidelines is provided in Attachment 1. Funding was offered to participants who qualified under the funding guidelines. A list of the invited participants is provided in Attachment 2. The presentation provided to stakeholders related to this application is provided in Attachment 3.

OPTIMUS | SBR prepared meeting notes that documented discussions and stakeholder comments and feedback received during this process. Once completed, the meeting notes will be available at http://www.opg.com/about/regulatory-affairs/Pages/regulatory-affairs.aspx

LIST OF ATTACHMENTS

Attachment 1:	Stakeholder Invitation Letter, Session Agenda and Funding Guidelines
Attachment 2:	List of Invited Participants
Attachment 3:	Presentation

ONTARIO POWER GENERATION

Randy Pugh
MBA, CPA-CMA, CPA-CGA
Director, Regulatory Affairs

Regulatory Affairs

700 University Avenue, Toronto, Ontario M5G 1X6

Tel: 416-592-3546 Fax: 416-592-8519
randy.pugh@opg.com

December 4, 2014

VIA EMAIL

Dear Stakeholder:

Information Session on Upcoming OPG Applications

The purpose of this letter is to invite you to participate in an information session on December 17, 2014. The session will provide information on:

1) The Total Factor Productivity (TFP) Study prepared by London Economics International LLC (LEI). The study is expected to be completed prior to the information session and will be filed with the OEB as directed in EB-2013-0321. Copies will be provided at this meeting; and,

2) The status of the upcoming Deferral and Variance Account Application, as discussed during the EB-2013-0321 Application.

Consistent with the OEB's expectations in EB-2012-0340, OPG's future rates will be established through an incentive regulation methodology for hydroelectric operations and a multi-year cost of service methodology for nuclear operations. The OEB has stated that it sees no reason for delay, and OPG believes that it is necessary to start a consultation expeditiously to minimize the potential for delays in the start of new rates. OPG will therefore also provide information on its hydroelectric and nuclear business environment for the five year period commencing in 2016. This initial meeting will be followed by additional sessions in early 2015. An independent facilitator will document and report on the discussions.

We are contacting representatives of aboriginal peoples and stakeholders who participated in the EB-2013-0321 proceeding and any others who we believe will have an interest in these discussions.

The full-day meeting will be held on December 17, 2014, from 9:00 am to 3:30 pm in the Mini-Auditorium, mezzanine level at OPG's head office, 700 University Avenue (corner of University Ave. and College St.) in Toronto.

The agenda is attached. All presentation materials will be posted on OPG's web-site, www.opg.com following the session.

OPG will provide funding for participation in the information session to eligible participants. A copy of the funding guidelines is attached for your information.

If you have any questions or would like to discuss OPG's consultation process please contact me at 416-592-3546. Please confirm your attendance at the session by December 12, 2014 by contacting Pina De Santis by email at pina.desantis@opg.com or by phone at 416-592-3703.

Best Regards,

Randy Pugh
MBA, CPA-CMA, CPA-CGA
Director, Regulatory Affairs

Attachments:

1. Meeting Agenda
2. OPG Participant Funding Guideline

Attachment 1

AGENDA

Information Session
December 17, 2014

Mini Auditorium – 700 University Avenue, Toronto, ON

8:45 a.m. – 9:00 a.m.	- Registration
9:00 a.m. – 9:15 a.m.	- Welcome - Introductions - Safety Rules - Agenda
9:15 a.m. – 10:00 a.m.	- Hydroelectric Overview
10:00 a.m. – 10:30 a.m.	- Discussion
10:30 a.m. – 10:45 a.m.	- Break
10:45 a.m. – 12:00 a.m.	- Hydroelectric TFP Study and Inflation Factor Assessment
12:00 a.m. – 12:30 p.m.	- Discussion
12:30 p.m. – 1:15 p.m.	- Lunch
1:15 p.m. – 2:00 p.m.	- Nuclear Overview
2:00 p.m. – 2:30 p.m.	- Discussion
2:30 p.m. – 2:45 p.m.	- Break
2:45 p.m. – 3:30 p.m.	- Status of the Deferral and Variance Accounts Application

Attachment 2

Participant Funding Guidelines

To facilitate dialogue with its stakeholders, Ontario Power Generation (OPG) will provide funding to assist qualifying stakeholders to participate in its information sessions. The funding criteria that will be used are based on the OEB's most recent Practice Direction on Cost Awards. The following provides eligibility guidelines and a description of the funding process.

Eligibility

- The determination of whether a party is eligible for funding will be at the sole discretion of OPG.
- Funding is limited to not-for-profit organizations whose interests are affected by the application such as public interest organizations, environmental organizations, and Aboriginal communities.
- Individuals and organizations with a direct commercial or business interest in the application are not eligible for funding. This includes, but may not be limited to, transmitters, wholesalers, generators, distributors, retailers and marketers, or organizations representing these interests.
- Municipal or provincial government staff or representatives are not eligible for funding.
- Parties with similar interests are encouraged to combine their participation.
- Funding will be provided only to stakeholders participating in the discussion session.

Process for Funding and Eligible expenses

- To allow timely processing of requests, it is suggested that stakeholders seeking funding apply to OPG at least 7 days prior to the session. Stakeholders should indicate in writing that they will be participating and include a statement justifying their eligibility. Parties should submit their request for financial support to:

  Mr. Randy Pugh
  Ontario Power Generation
  700 University Ave. H18-D1,
  Toronto, ON M5G 1X6

  Fax: 416-592-8519
  Email: randy.pugh@opg.com

- OPG will notify the party prior to the session if their funding application is accepted.
- Funding will be provided for meeting preparation and attendance for one person based on rates outlined in the OEB's Cost Award Tariff.
- Preparation time is not to exceed an amount equal to the meeting time. Preparation time is only allowed if the stakeholder attends the session.
- Out of pocket travel expenses will be allowed including reasonable meals and accommodation only if the participant's place of business is greater than 100 km from the meeting site. Receipts must be submitted for all meals, accommodations and travel with the exception of mileage for personal automobile.

- Reasonable disbursements, such as postage, photocopying, etc., are eligible expenses.
- Eligible participants must submit an OPG disbursement claim sheet form complete with receipts, no later than 30 days after the session.

December 17, 2014

Information Meeting Invitations List

Organization	Contact
Association of Iroquois and Allied Indians	Grand Chief Gord Peters
Association of Major Power Consumers in Ontario	Adam White
Association of Major Power Consumers in Ontario	Shelley Grice
Association of Power Producers of Ontario	David Butters
Bruce Power	Richard Horrobin
Canadian Federation of Independent Business	Plamen Petkov
Canadian Manufacturers and Exporters	Paul Clipsham
Canadian Manufacturers and Exporters	Vincent DeRose
Canadian Manufacturers and Exporters	Ian Howcroft
Chiefs of Ontario	Ontario Regional Chief Stan Beardy
Consumers Council of Canada	Julie Girvan
Electricity Distributors Association	Teresa Sarkesian
Enbridge Gas Distribution Inc.	Andrew Mandyam
Energy Probe Research Foundation	David MacIntosh
Energy Probe Research Foundation	Norm Rubin
Environmental Defence	Kent Elson
Environmental Defence	Jack Gibbons
EnWin Utilities Ltd.	Andrew Sasso
Grand Council of Treaty #3	Grand Chief Warren White

Organization	**Contact**
Green Energy Coalition	Kai Millyard
Green Energy Coalition	David Poch
Haudenosaunee Development Institute	Aaron Detlor
Hydro One Networks Inc.	Susan Frank
Hydro Quebec	Matthieu Plante
Independent Electricity System Operator	Paula L. Lukan
Independent Electricity System Operator	Tam Wagner
Lake Ontario Waterkeeper	Mark Mattson
London Property Management Association	Randy Aiken
Métis Nation of Ontario	Gary Lipinski
Ministry of Energy	Danish Khaliq
Nishnawbe Aski Nation	Grand Chief Harvey Yesno
Ontario Chamber of Commerce	Liam McGuinty
Ontario Energy Board	Violet Binette
Ontario Mining Association	Cheryl Brownlee
Ontario Power Authority	Miriam Heinz
Pollution Probe	Husam Mansour
Power Workers' Union	John Sprackett
Power Workers' Union	Kim McKenzie
Retail Council of Canada	Gary Rygus
School Energy Coalition	Wayne McNally
School Energy Coalition	Jay Shepherd

Organization	**Contact**
Shell Energy North America (Canada) Inc.	Paul Kerr
Society of Energy Professionals	Mike Belmore
Society of Energy Professionals	Richard Long
Sustainability-Journal.ca	Ron Tolmie
TransCanada	Murray Ross
Union Gas	Chris Ripley
Union of Ontario Indians	Grand Council Chief Patrick Madahbee
Vulnerable Energy Consumers Coalition	Michael Janigan
Vulnerable Energy Consumers Coalition	James Wightman

VALUES ▪ SAFETY ▪ INTEGRITY ▪ EXCELLENCE ▪ PEOPLE AND CITIZENSHIP

Deferral and Variance Account Application

December 17, 2014

Garry Hendel
Senior Manager, Regulatory Affairs

ONTARIO POWER GENERATION

Scope of OPG's Application

Seeks clearance of deferral and variance account balances, as at December 31, 2014

- Total December 31, 2014 balances are approximately $2B.
- OPG is seeking to recover all December 31, 2014 balances except balances in the two Pension and OPEB accounts (*Cash vs. Accrual* and *Cash vs. Cash*) established in EB-2013-0321 (projected balances of approximately $70M).
- A portion of the December 31, 2014 balances (four accounts with a combined balance of approximately $190M) was approved for recovery in EB-2013-0321.
- OPG is therefore applying to recover the remaining balances of about $1.75B.
- OPG will file its application based on projected 2014 account balances and will provide audited account balances in February 2015. As the projections are based on 10 months actual experience in 2014, the projected balances are expected to be fairly close to actual balances

Application Summary

- OPG is applying for:
  - With the exception of the new pension and OPEB accounts approved in EB-2013-0321, OPG will apply to recover the December 31, 2014 balances in all other deferral and variance accounts.
  - 18 month clearance (July 1, 2015 through December 31, 2016) for all above accounts except the Pension and OPEB Cost Variance Account and the Bruce Lease Net Revenues Variance Account.
  - For the Pension and OPEB Cost Variance Account and the Bruce Lease Net Revenues Variance Account, OPG proposes to:

    a) Continue to dispose of the remaining portion of the December 31, 2012 balances as per the terms of the OEB-approved settlement in EB-2012-0002.

    b) For amounts accrued in the Pension & OPEB Cost Variance Account after December 31, 2012, clearance will occur over a 24 month period (July 1, 2015 to June 30, 2017.)
  - Riders effective July 1, 2015 through Dec 31, 2016.
  - Separate payment riders for the nuclear and hydroelectric accounts. Common rider will be used for previously and newly regulated hydroelectric account balance recovery.
- As the recovery term extends beyond December 31, 2016 as noted above, the amount OPG plans to recover in the 2015 to 2016 period is approximately $1.3B.
- Increase in customer bills resulting from this application is estimated to be approximately $3.08/month for a typical residential customer
- Rider calculations use approved 2014-15 production forecasts.

Current and Proposed Regulated Hydroelectric Payment Amounts and Riders

	Current		Proposed	
	2014 Nov – Dec ($/MWh)	**2015 Jan – Jun** ($/MWh)	**2015 Jul – Dec** ($/MWh)	**2016** ($/MWh)
Previously Regulated Hydro				
Base Payment Amount	40.20	40.20	40.20	40.20
Previously Approved D&V Rider	2.02	6.04	6.04	-
Proposed Rider	-	-	3.78	3.78
Total	42.22	46.24	50.02	43.98
Newly Regulated Hydro				
Base Payment Amount	41.93	41.93	41.93	41.93
EB-2013-0321 Approved D&V Rider	-	-	-	-
Proposed Rider	-	-	3.78	3.78
Total	41.93	41.93	45.71	45.71

Current and Proposed Nuclear Payment Amounts and Riders

	Current		Proposed	
	2014 Nov – Dec ($/MWh)	2015 Jan – Jun ($/MWh)	2015 Jul – Dec ($/MWh)	2016 ($/MWh)
Regulated Nuclear				
Base Payment Amount	59.29	59.29	59.29	59.29
Previously Approved D&V Rider	4.18	1.33	1.33	-
Proposed Rider	-	-	15.78	15.78
Total	63.47	60.62	76.40	75.07

Previously Regulated Hydroelectric– Projected 2014 Year End Balances ($M)

Account	Projected Year End Balance 2014	Deferred or OEB-Approved for Recovery	Balances Requested for Recovery	Balance Recovered 2015 to 2016 Through Proposed Rider	Balance for Recovery after Dec 31, 2016
	(a)	(b)	(c) = (a) – (b)	(d)	(e) = (c) – (d)
Hydroelectric Water Conditions Variance	9.5	-	9.5	9.5	-
Ancillary Services Net Revenue Variance – Hydroelectric	(10.7)	-	(10.7)	(10.7)	-
Hydroelectric Incentive Mechanism Variance	(7.5)	(5.0)	(2.5)	(2.5)	-
Hydroelectric Surplus Baseload Generation Variance	46.6	19.2	27.4	27.4	-
Income and Other Taxes Variance - Hydroelectric	(0.1)	-	(0.1)	(0.1)	-
Tax Loss Variance - Hydroelectric	-	-	-	-	-
Capacity Refurbishment Variance - Hydroelectric	232.6	112.7	119.9	119.9	-
Gross Revenue Charge Variance Account	-	-	-	-	-
Pension and OPEB Cost Variance - Hydroelectric - Historic	-	-	-	-	-
Pension and OPEB Cost Variance - Hydroelectric - Future	10.5	-	10.5	2.1	8.4
Pension and OPEB Cost Variance - Hydroelectric - post 2012 Additions	35.5	-	35.5	26.6	8.9
Pension and OPEB Cash Versus Accrual Differential Deferral Account	3.3	3.3	-	-	-
Pension and OPEB Cash Payment Variance Account	(0.2)	(0.2)	-	-	-
Impact for USGAAP Deferral - Hydroelectric	-	-	-	-	-
Hydroelectric Deferral and Variance Over/Under Recovery Variance	3.7	-	3.7	3.7	-
Total	323.2	130.1	193.1	175.8	17.3

▪ SAY IT DO IT ▪ SIMPLIFY IT ▪ THINK TOP AND BOTTOM LINE ▪ INTEGRATE AND COLLABORATE ▪ TELL IT AS IT IS

ONTARIO POWER GENERATION

Newly Regulated Hydroelectric – Projected 2014 Year End Balances ($M)

Account	Projected Year End Balance 2014	Deferred or OEB-Approved for Recovery	Balances Requested for Recovery	Balance Recovered 2015 to 2016 Through Proposed Rider	Balance for Recovery after Dec 31, 2016
	(a)	(b)	(c) = (a) – (b)	(d)	(e) = (c) – (d)
Hydroelectric Water Conditions Variance	3.2	-	3.2	3.2	-
Ancillary Services Net Revenue Variance - Hydroelectric	0.2	-	0.2	0.2	-
Hydroelectric Incentive Mechanism Variance	-	-	-	-	-
Hydroelectric Surplus Baseload Generation Variance	5.4	-	5.4	5.4	-
Income and Other Taxes Variance - Hydroelectric	-	-	-	-	-
Capacity Refurbishment Variance - Hydroelectric	-	-	-	-	-
Pension and OPEB Cash Versus Accrual Differential Deferral Account	5.8	5.8	-	-	-
Pension and OPEB Cash Payment Variance Account	(0.7)	(0.7)	-	-	-
Hydroelectric Deferral and Variance Over/Under Recovery Variance	-	-	-	-	-
Total	13.9	5.2	8.7	8.7	-

Nuclear– Projected 2014 Year End Balances ($M)

Account	Projected Year End Balance 2014	Deferred or OEB-Approved for Recovery	Balances Requested for Recovery	Balance Recovered 2015 to 2016 Through Proposed Rider	Balance for Recovery after Dec 31, 2016
	(a)	(b)	(c) = (a) – (b)	(d)	(e) = (c) – (d)
Nuclear Liability Deferral	286.3	-	286.3	286.3	-
Nuclear Development Variance	59.0	56.5	2.5	2.5	-
Ancillary Services Net Revenue Variance - Nuclear	1.7	-	1.7	1.7	-
Capacity Refurbishment Variance - Nuclear - Capital Portion	13.1	5.7	7.4	7.4	-
Capacity Refurbishment Variance - Nuclear - Non-Capital Portion	6.7	-	6.7	6.7	-
Bruce Lease Net Revenues Variance - Derivative Sub-Account	129.9	-	129.9	53.8	76.1
Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account	37.3	-	37.3	37.3	-
Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions	126.8	-	126.8	126.8	-
Income and Other Taxes Variance - Nuclear	(8.5)	-	(8.5)	(8.5)	-
Tax Loss Variance - Nuclear	-	-	-	-	-
Pension and OPEB Cost Variance - Nuclear - Historic	-	-	-	-	-
Pension and OPEB Cost Variance - Nuclear - Future	214.7	-	214.7	42.9	171.7
Pension and OPEB Cost Variance - Nuclear - post 2012 Additions	678.6	-	678.6	509.0	169.7
Pension and OPEB Cash Versus Accrual Differential Deferral Account	62.0	62.0	-	-	-
Pension and OPEB Cash Payment Variance Account	(0.8)	(0.8)	-	-	-
Impact for USGAAP Deferral - Nuclear	-	-	-	-	-
Pickering Life Extension Depreciation Variance	7.8	-	7.8	7.8	-
Nuclear Deferral and Variance Over/Under Recovery Variance	57.4	-	57.4	57.4	-
Total	1,671.9	123.4	1,548.5	1131.1	417.5

ONTARIO POWER GENERATION

Questions?

PROCEDURAL ORDERS, CORRESPONDENCE, NOTICES

To be filed when available.

LIST OF WITNESSES

To be filed when available.

CURRICULA VITAE OF WITNESSES

To be filed when available.

OVERVIEW OF DEFERRAL AND VARIANCE ACCOUNTS

1.0 PURPOSE

This evidence provides an overview of OPG's deferral and variance accounts and presents the amounts recorded in the accounts since they were last approved for clearance and the projected year-end 2014 balance in each account. These accounts were established pursuant to O. Reg. 53/05 and the OEB's decisions in EB-2007-0905, EB-2009-0038, EB-2009-0174, EB-2010-0008, EB-2011-0090, EB-2011-0432, EB-2012-0002 and EB-2013-0321.

2.0 OVERVIEW

The balances in all accounts, including additions to accounts during 2013 and projected 2014 additions, are shown in Ex. H1-1-1 Table 1. The projected total year-end 2014 debit balance is $337.1M for the regulated hydroelectric facilities (consisting of $323.4M for previously regulated and $13.8M for newly regulated) and $1,671.9M for the nuclear facilities[1].

In this proceeding, OPG proposes to clear the audited balances in all accounts as at December 31, 2014, with the exception of the new accounts established in EB-2013-0321. OPG expects that the audited balances will be available in mid–February of 2015 and will be filed then. Given that the projected balances reflect ten months of actual data, OPG does not anticipate that the audited balances will be significantly different from projected balances shown in this Application. Details regarding proposed account clearance and riders are presented in Ex. H1-2-1.

3.0 LISTING OF ACCOUNTS

The OEB has authorized variance and deferral accounts for OPG as listed below. Entries into these accounts for 2013 and 2014 have been calculated in accordance with the applicable OEB decisions and orders. The December 31, 2012 balances in all authorized accounts were approved by the OEB in EB-2012-0002, with the exception of four accounts

[1] A debit entry or balance is an amount to be collected from ratepayers. A credit entry or balance is an amount to be returned to ratepayers.

that were reviewed and had their audited December 31, 2013 balances approved by the OEB in EB-2013-0321. The four accounts are: 1) the Hydroelectric Incentive Mechanism Variance Account, 2) the Hydroelectric Surplus Baseload Generation Variance Account, 3) the nuclear capital and hydroelectric capital and non-capital portions of the Capacity Refurbishment Variance Account, and 4) the Nuclear Development Variance Account.

Pre-existing Accounts in EB-2013-0321:

- Hydroelectric Water Conditions Variance Account
- Ancillary Services Net Revenue Variance Account
- Hydroelectric Incentive Mechanism Variance Account
- Hydroelectric Surplus Baseload Generation Variance Account
- Income and Other Taxes Variance Account
- Tax Loss Variance Account[2]
- Capacity Refurbishment Variance Account
- Pension and OPEB Cost Variance Account
- Impact for USGAAP Deferral Account[2]
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
- Nuclear Liability Deferral Account
- Nuclear Development Variance Account
- Bruce Lease Net Revenues Variance Account
- Pickering Life Extension Depreciation Variance Account
- Nuclear Deferral and Variance Over/Under Recovery Variance Account

Newly authorized accounts in EB-2013-0321, effective November 1, 2014:

- Gross Revenue Charge Variance Account
- Pension and OPEB Cash Payment Variance Account
- Pension and OPEB Cash Versus Accrual Differential Deferral Account

As this Application does not propose disposing of the balances in the above three accounts, no discussion of them appears below.

[2] These two accounts will be terminated on December 31, 2014 as per EB-2013-0321.

4.0 ACCOUNT BALANCES[3]

Exhibit H1-1-1, Table 1 summarizes the year-end balances for 2012 through 2014. Exhibit H1-1-1, Tables 1a through 1c are continuity tables which, for each account, show the opening balances, additions (labelled “Transactions”), amortization subtracted and interest added, any transfers between accounts during the period, and the closing balances by time period. Exhibit H1-1-1, Tables 2 through 14 provide supporting calculations showing the derivation of additions into these accounts since their balances were last approved by the OEB.

Where applicable, additions for 2013 have been calculated with reference to amounts underpinning the payment amounts approved in EB-2010-0008, in accordance with the methodologies approved in EB-2012-0002. All 2013 balances for previously regulated hydroelectric and nuclear facilities are the same as the actual balances presented in EB-2013-0321, Ex. L-9.1-17 SEC-132, Attachment 1, Table 1 (corrected version filed on June 4, 2014). Additions for January through October 2014 have been calculated with reference to the same amounts underpinning the payment amounts approved in EB-2010-0008. Additions for November and December 2014 are calculated with reference to the amounts underpinning the EB-2013-0321 payment amounts in accordance with the methodologies approved in EB-2013-0321.

In EB-2013-0321, OPG indicated it is not seeking to recover from, or refund to, ratepayers part of the differences between the revenue requirement in its pre-filed evidence dated September 27, 2013 and the information based on OPG’s 2014-2016 Business Plan. These amounts are outlined in OPG’s Impact Statement dated December 6, 2013, as found at EB-2013-0321, Ex. N1-1-1 Chart 1. This approach, approved in EB-2013-0321, results in adjustments to the November and December 2014 entries in the Ancillary Services Net Revenue Variance Account, Capacity Refurbishment Variance Account-Nuclear and Bruce Lease Net Revenues Variance Account as shown in Tables 3, 12 and 13, respectively.

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[3] Amounts cited may not calculate due to rounding

Except for accounts that do not attract interest as noted below, interest is applied to the monthly opening balance of the accounts at the OEB-prescribed rates. The projected 2014 year-end balances reflect interest at the current prescribed rate of 1.47 per cent per annum.

The amortization presented for 2013 and 2014 is as per Appendix B of the EB-2012-0002 Payment Amounts Order.

5.0 ACCOUNT DESCRIPTIONS AND ENTRIES

This section provides brief descriptions of the deferral and variance accounts that OPG seeks to clear in this Application and the reasons for the credits and debits to the accounts since the balances were approved by the OEB.

5.1 Hydroelectric Water Conditions Variance Account

This account records the financial impact (including changes in gross revenue charge and water rental costs) of differences between forecast and actual water conditions. The Hydroelectric Water Conditions Variance Account applies to the previously regulated hydroelectric facilities and 21 of the newly regulated hydroelectric facilities. OPG maintains separate sub-accounts for the previously and newly regulated hydroelectric prescribed assets.

The balances for 2013 and January through October 2014 are based on the forecast methodology approved in EB-2012-0002 (as described in EB 2012-0002, Payment Amounts Order, Appendix B, pages 3-4). The projected additions for November and December 2014 are based on the production forecast and methodology approved in EB-2013-0321.

Due to unfavourable water supply conditions (i.e., precipitation) affecting the Niagara and St. Lawrence Rivers in 2013, the calculated hydroelectric production was less than the reference forecast production by 664 GWh. This variance resulted in a net debit entry of $15.2M to the account during 2013.

Due to favourable water supply conditions affecting the Niagara and St. Lawrence rivers in 2014, the projected calculated hydroelectric production is expected to be higher than the reference forecast production by 272 GWh. This variance is expected to result in a projected net credit of $6.3M during 2014. Expected conditions for the newly regulated hydroelectric facilities in November and December of 2014 result in a projected net debit of $3.2M. The derivations of these variances are shown in Ex. H1-1-1, Table 2.

5.2 Ancillary Services Net Revenue Variance Account

OPG uses sub accounts to record differences between actual hydroelectric and nuclear ancillary services net revenues and forecast amounts reflected in the approved revenue requirement. OPG maintains separate sub-accounts for the previously and newly regulated hydroelectric prescribed assets.

Hydroelectric and nuclear ancillary services net revenues were lower in 2013 than the amounts underpinning the EB-2010-0008 payment amounts. The decrease was due to:

- increased competition resulting in lower prices for operating reserve,
- lower than expected regulation service (formerly automatic generation control) revenues due to the elimination of the Global Adjustment charge associated with the use of the Sir Adam Beck Pump Generating Station under O. Reg. 429/04 as amended, and
- lower reactive power revenue at Pickering A due to lower prices (the reactive power contract is HOEP based).

These factors resulted in debit entries of $1.8M and $1.2M to the Hydroelectric and Nuclear Ancillary Services Net Revenue Variance Sub Accounts, respectively.

Ancillary services net revenues are projected to total $12.8M higher in 2014 than the amounts underpinning the EB-2010-0008 and EB-2013-0321 payment amounts. This total is comprised of higher revenues from the previously regulated hydroelectric ($12.9M), and slightly lower revenues from the newly regulated hydroelectric (-$0.2M) and nuclear (-$0.4M) facilities. The overall increase in ancillary revenues is primarily due to higher prices for regulation service and operating reserve from the previously regulated hydroelectric facilities, slightly offset by lower revenues from nuclear and the other adjustments discussed below.

For November and December 2014, adjustments are also made to ensure that amounts recorded in the account do not include those that OPG indicated it is not seeking to recover from, or refund to, ratepayers as part of the differences between the revenue requirement in its pre-filed evidence in EB-2013-0321 dated September 27, 2013 and the information based on OPG's 2014-2016 Business Plan.

The derivations of account entries for 2013 and 2014 are shown in Ex. H1-1-1 Table 3.

5.3 Hydroelectric Incentive Mechanism Variance Account

This account was reviewed in EB-2013-0321. The approved December 31, 2013 balance is a credit of $5.0M. This balance is being cleared over 12 months effective January 1, 2015 as ordered in EB-2013-0321.

This account records a credit to ratepayers for 50 per cent of hydroelectric incentive mechanism ("HIM") net revenues above a threshold amount established by the OEB. In EB-2012-0002, the threshold was established at $13M per calendar year after December 31, 2012. Thus the threshold for January through October 2014 is $10.8M (10/12 of $13M). The derivation of projected additions to the account for 2014 is shown in Ex. H1-1-1, Table 4. Credit additions to this account from January 1, 2014 to October 31, 2014 total $2.4M and have been made in accordance with the OEB's order in EB-2012-0002.

For November and December 2014, this account will record a credit to ratepayers equal to 50 per cent of OPG's total HIM net revenues from the prescribed hydroelectric facilities above $8.5M, being 2/12 of the 2014 annual threshold of $51M, as shown in the EB-2013-0321 Payment Amounts Order. The projected 2014 HIM net revenues for both previously and newly regulated hydroelectric combined total $5.6M. As this amount is less than the threshold, the November and December 2014 entry in this account is projected to be zero.

5.4 Hydroelectric Surplus Baseload Generation Variance Account

This account was reviewed in EB-2013-0321. The approved December 31, 2013 balance is $19.2M. This balance is being cleared over 12 months effective January 1, 2015 as ordered in EB-2013-0321.

The Hydroelectric Surplus Baseload Generation Variance Account was originally approved in EB-2010-0008 for the previously regulated hydroelectric facilities and was extended to 21 of the newly regulated hydroelectric facilities in EB-2013-0321. OPG maintains separate sub-accounts for the previously and newly regulated hydroelectric prescribed assets. This account records the financial impact (including changes in gross revenue charges and water rental costs) of foregone production at OPG's prescribed hydroelectric facilities due to surplus baseload generation ("SBG") conditions in accordance with the Payment Amounts Order in EB 2013-0321.

Additions to this account from January 1, 2014 to October 31, 2014 have been made in accordance with the OEB's order in EB-2012-0002. Additions to this account for November and December 2014 are made in accordance with the OEB's order in EB 2013-0321.

The derivation of projected additions to the account for 2014 is shown in Ex. H1-1-1 Table 5. Projected 2014 foregone production due to SBG conditions is 1,230 GWh for the previously regulated hydroelectric facilities and 175.4 GWh for newly regulated hydroelectric facilities. After a deduction of avoided gross revenue charge and water rental costs, the projected 2014 debit entries are $27.1M associated with the previously regulated hydroelectric facilities and $5.4M associated with the newly regulated hydroelectric facilities (covering only November and December 2014).

5.5 Income and Other Taxes Variance Account

This account records the financial impact on the regulated hydroelectric and nuclear revenue requirement of variations in payments in lieu of corporate income and capital taxes for OPG's prescribed assets resulting from changes to the tax rates or rules, assessments or re-assessments, new tax policies, and court decisions. The account also records variations in municipal property taxes and payments in lieu of property tax for the prescribed assets resulting from legislative or regulatory changes, including changes in municipal property tax rates or rules. The account was extended to the newly regulated hydroelectric facilities in EB-2013-0321.

For 2013 and January through October 2014, OPG recorded five entries into this account as follows:

1. A credit entry related to an increase in the recognition of Scientific Research and Experimental Development ("SR&ED") investment tax credits ("ITCs") from 50 per cent to 75 per cent based on the completion of the 2002-2005 income tax audit in 2011;
2. A debit entry related to a decrease in SR&ED ITCs due to a reduction from 100 per cent to 80 per cent of the amount of payments to contractors qualifying for ITCs, effective 2013, as a result of the 2012 federal budget;
3. A debit entry related to the portion of nuclear waste management expenditures deemed to be capital for tax purposes following the resolution of a prior year tax audit;
4. A credit entry related to an increase in the recognition of SR&ED ITCs for the period from April 1, 2008 to December 31, 2008 (in 2013) and full year 2009 (in 2014) from 75 per cent to 100 per cent based on the completion of the 2008 income tax audit (in 2013) and the 2009 income tax audit (in 2014); and
5. A debit entry related to the reduction in the federal SR&ED ITC rate from 20 per cent to 15 per cent effective in 2014, as per the 2012 federal budget.

As shown in Ex. H1-1-1, Table 6, the impact of these entries for 2013 is a net credit to ratepayers of $4.6M and for January through October 2014 is a net credit to ratepayers of $3.5M.

Entries (1) and (3) were recorded during 2013 and 2014 using the same methodology as similar entries in 2011 and 2012, which were reflected in the December 31, 2012 balance in this account and discussed and approved in EB-2012-0002.[4] Entry (2) results from changes to the SR&ED ITC rules in the 2012 federal budget effective in 2013. The three entries were also discussed in EB-2013-0321, Ex. F4-2-1, sections 3.2 and 3.5.

Entry (4) recognizes a credit to ratepayers of an additional 25 per cent of the benefit of SR&ED ITCs for the period from April 1, 2008 to December 31, 2008 (in 2013) and full year 2009 (in 2014) that were previously credited to ratepayers at 75 per cent (through entries into the Income and Other Taxes Variance Account approved in EB-2010-0008 and EB-2012-0002). In all other respects, this entry was recorded using the same methodology as entry (1).

Entry (5) recorded for the period January through October 2014 results from a reduction, effective in 2014, in the federal ITC rate from 20 per cent to 15 per cent in the 2012 federal budget that was not reflected in the EB-2010-0008 payment amounts. The rate reduction was also discussed in EB-2013-0321, Ex. F4-2-1, section 3.5.

OPG does not expect any additions into the variance account for November and December 2014 as the EB-2013-0321 payment amounts already reflect the impact of applicable items above.

5.6 Tax Loss Variance Account

The Tax Loss Variance Account was established effective April 1, 2008 in EB-2009-0038 to record the variance between the tax loss amount underpinning the EB-2007-0905 payment amounts and the tax loss amount resulting from the re-analysis of OPG's prior period tax returns based on the OEB's directions in the EB-2009-0038 Decision and Order. This account only records interest and amortization effective March 1, 2011 and, pursuant to the EB-2013-0321 Payment Amounts Order, will be terminated at the end of the approved recovery period on December 31, 2014. Interest of $3.0M was recorded in the account during 2013. Interest of $0.7M is projected to be recorded in the account during 2014. At the end of the 2014, the remaining balances in this account, projected as $0.5M for hydroelectric

[4] EB-2012-0002, Ex. H1-1-1, section 4.2

and $3.2M for nuclear, will be transferred to the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and Nuclear Deferral and Variance Over/Under Recovery Variance Account, respectively as shown in Ex. H1-1-1 Table 1c.

5.7 Capacity Refurbishment Variance Account

This account was established pursuant to section 6(2)4 of O. Reg. 53/05 to record variances between the actual capital and non-capital costs and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a prescribed generation facility referred to in section 2 of O. Reg. 53/05 and those forecast costs and firm financial commitments reflected in the revenue requirement approved by the OEB. In EB-2013-0321, the OEB authorized inclusion of applicable expenditures on the newly regulated hydroelectric facilities into this account effective November 1, 2014.

In EB-2012-0002, the OEB approved the deferral of the clearance of portions of this account to the next payment amounts proceeding. In EB-2013-0321, the OEB reviewed the deferred portions, which comprised variances recorded in 2011 and 2012 for capital and non-capital costs for the regulated hydroelectric facilities related primarily to the Niagara Tunnel project (“NTP”) and additions recorded in 2012 related to Darlington Refurbishment capital cost variances. In EB-2013-0321 the audited December 31, 2013 balances in these portions of the account were approved for clearance over 12 months commencing January 1, 2015. The approved amounts were $112.7M for hydroelectric variances and $5.7M for nuclear capital cost variances.

Regulated Hydroelectric

The December 31, 2014 regulated hydroelectric balance for both previously and newly regulated facilities is projected to be a debit of $232.6M, as shown in Ex. H1-1-1 Table 1.[5] The projected additions for 2014 of $117.4M include $115.8M related to the NTP to November 1, 2014, the effective date of the EB-2013-0321 payment amounts, and $1.6M related to several other, smaller regulated hydroelectric capital projects. Additions for capital

[5] Of this amount, $112.7M represents the 2013 balance approved for clearance in EB-2013-0321 and $119.4M represents 2014 transactions and interest.

cost variances for the NTP and other projects are derived using the same methodology as the approved December 31, 2013 portion of the account.

The derivation of the regulated hydroelectric account additions for 2014 is shown in Ex. H1-1-1 Table 7.

Nuclear

The derivation of 2013 (non-capital) and 2014 (non-capital and capital) account additions for the nuclear facilities is shown in Ex. H1-1-1 Tables 12 and 12a.

For November and December 2014, adjustments are also made to both the non-capital and capital additions to ensure that amounts recorded in the account do not include those that OPG indicated it is not seeking to recover from, or refund to, ratepayers as part of the differences between the revenue requirement in its pre-filed evidence in EB-2013-0321, dated September 27, 2013, and the information based on OPG's 2014-2016 Business Plan. These adjustments are shown Ex. H1-1-1, Table 12, lines 16 and 33.

Nuclear Non-Capital Additions

As shown in Ex. H1-1-1 table 12, the 2013 nuclear non-capital cost additions are a net debit of $4.0M and relate to Darlington Refurbishment, the Fuel Channel Life Management ("FCLM") project and Pickering Continued Operations. The projected nuclear non-capital cost 2014 net debit additions of $2.4M also relate to these projects, as well as the Fuel Life Channel Extension ("FCLE") project.

The 2013 nuclear non-capital cost additions primarily relate to the $3.3M debit entry for the FCLM project. The January through October 2014 additions mainly reflect a $9.6M credit entry for Pickering Continued Operations, partly offset by debit entries of $2.9M and $3.0M for the FCLM and the FCLE projects, respectively.

The 2013 and January through October 2014 variances for the FCLM project and Pickering Continued Operations results from actual costs that are higher (FCLM) or lower (Pickering Continued Operations) than the average of the corresponding 2011 and 2012 forecasts underpinning the EB-2010-0008 payment amounts. The FCLM project and Pickering Continued Operations were discussed in EB-2013-0321 Ex. F2-2-3.

The projected November and December 2014 non-capital cost additions primarily reflect a $3.5M debit entry for Pickering Continued Operations and a $2.2M debit entry for the FCLE project.

The FCLE project debit entries for 2014 represents the full amount of costs incurred for the project during the period, as the project was not reflected in the forecasts underpinning the EB-2010-0008 payment amounts, or OPG's 2013-2015 Business Plan underpinning the EB-2013-0321 payment amounts.

Nuclear Capital Additions

The entire $13.1M projected nuclear capital cost balance at December 31, 2014 relates to Darlington Refurbishment projects.[6] The 2014 additions are derived using the same methodology as the approved December 31, 2013 portion of the account.

For January through October 2014, the debit capital cost variance additions reflect the impacts of 2013/2014 in-service amounts for the projects previously reflected in the approved December 31, 2013 balance of the account (Darlington Energy Complex, Water and Sewer project, and Electrical Power Distribution System project), as well as a portion of the Heavy Water Storage and Drum Handling Facility project placed in-service in 2014. There were no in-service amounts reflected for these projects in the forecasts underpinning the EB-2010-

[6] Of this amount, $5.7M represents the 2013 balance approved for clearance in EB-2013-0321 and $7.2M represents 2014 activity.

0008 payment amounts. These projects were discussed in EB-2013-0321 Ex. D2-2-1, Attachment 5 and Ex. D2-2-2.

The projected cost of capital debit additions of $0.9M for November and December 2014 reflect variances from forecasts underpinning the EB-2013-0321 payment amounts in relation to the in-service timing and amount of the Darlington Refurbishment projects, including the Heavy Water Storage and Drum Handling Facility, Water and Sewer Project, and Electrical Power Distribution System projects.

5.8 Pension and OPEB Cost Variance Account

Prior to November 1, 2014, this account recorded the difference between: (1) the accrual pension and OPEB costs, plus related income tax PILs, reflected in the revenue requirement approved by the OEB, and (2) OPG's actual accrual pension and OPEB costs, and associated tax impacts, for the prescribed generation facilities. Based on the OEB's EB-2013-0321 decision, OPG is not recording new additions in this account after October 31. 2014.

As ordered by the OEB in EB-2012-0002, the balance in this account as at December 31, 2012, including interest accrued to that date, was split into the Historic Recovery and Future Recovery components. The approved Historic Recovery component was set at 2/12^{ths} of the total account balance as at December 31, 2012. The approved Future Recovery component was set at 10/12^{ths} of the total balance as at December 31, 2012. In order to facilitate the presentation of entries into the account OPG has shown the projected account additions for 2013 and the first ten months of 2014 as a separate entry (labelled "Post 2012 Additions"). All of the components are shown separately in Ex. H1-1-1 Table 1 for each of previously regulated hydroelectric and nuclear facilities.

The total projected December 31, 2014 debit balance in the account is $939.2M, with $46.0M attributable to previously regulated hydroelectric and $893.3M to nuclear, as shown in Ex. H1-1-1, Table 1. The derivation of the 2013 and 2014 debit account additions totalling

$714.0M ($35.5M for previously regulated hydroelectric and $678.6M for nuclear) is shown in Ex. H1-1-1, Tables 8 and 8a.

The 2013 and 2014 additions were calculated based on the forecasts underpinning the EB-2010-0008 payment amounts in accordance with the EB-2012-0002 Payment Amounts Order, using the methodology reflected in the year-end 2012 approved account balance. As required by the EB-2012-0002 Payment Amounts Order, accrual pension and OPEB costs used in the calculation of account additions in 2013 and the first ten months of 2014 were determined in accordance with Canadian GAAP, as the forecast pension and OPEB costs underpinning the approved EB-2010-0008 revenue requirement were also determined on that basis. The 2013 and 2014 account additions were calculated and recorded in a manner consistent with that reflected in the December 31, 2012 account balance approved in EB-2012-0002. OPG's 2013 and 2014 pension and OPEB costs were determined by OPG's independent actuary, Aon Hewitt. The accrual accounting methodology used in determining the costs is described in detail in EB-2013-0321, Ex. F4-3-1, section 6.3.[7]

Account additions in 2013 and 2014 reflect pension and OPEB costs that are higher than the EB-2010-0008 forecast amounts, primarily due to a significant decline in interest rates since the EB-2010-0008 forecasts were developed. In addition, updated mortality assumptions arising from a new comprehensive accounting valuation of pension and OPEB plan obligations as at December 31, 2013, as performed by OPG's independent actuary, and a lower expected long-term rate of return on the pension fund assets are significant factors contributing to the increase in the costs relative to the EB-2010-0008 forecasts. For pension costs, the increase was partly offset by the impact of the higher-than-forecast pension fund asset values. For OPEB costs, the increase was partly offset by the forecast of lower per capita health care benefit costs as part of the comprehensive accounting valuation, primarily due to the increase use and reduced pricing of generic drugs. The December 31, 2013 comprehensive accounting valuation and the update to mortality assumptions are discussed

[7] This evidence describes accrual accounting under US GAAP. The differences between US GAAP and Canadian GAAP for pension and OPEB costs relates to the long-term disability benefit plan, as discussed in EB-2013-0321 (Ex. A2-1-1, section 4.0), EB-2012-0002 and EB-2011-0432.

in detail in EB-2013-0321 Ex. N1-1-1, Ex. N2-1-1 and Ex. L-6.8-1 Staff-112, including accompanying attachments.

Chart 1 below presents the assumptions used to determine the 2013 and 2014 pension and OPEB costs as well as those used to derive the EB-2010-0008 forecasts.

Chart 1: Pension and OPEB Cost Assumptions (Canadian GAAP)

	2013 Actual	2014 Projection	2011 OEB-Approved	2012 OEB-Approved
Discount rate for pension	**4.30% per annum**	**4.90% per annum**	6.80% per annum	6.80% per annum
Discount rate for other post retirement benefits	**4.40% per annum**	**5.00% per annum**	7.00% per annum	7.00% per annum
Discount rate for long-term disability	**3.50% per annum**	**4.10% per annum**	5.25% per annum	5.25% per annum
Expected long-term rate of return on pension fund assets	**6.25% per annum**	**6.25% per annum**	7.0% per annum	7.0% per annum
Inflation rate	**2.0% per annum**	**2.0% per annum**	2.0% per annum	2.0% per annum
Salary schedule escalation rate	**2.5% per annum**	**2.5% per annum**	3.0% per annum	3.0% per annum
Rate of return used to project year-end pension fund asset values[8]	**N/A**	**N/A**	9.0% in 2009 and 7.0% per annum in 2010	9.0% in 2009 and 7.0% per annum in each of 2010 and 2011

The development of these assumptions is discussed in EB-2013-0321 Ex. F4-3-1, section 6.3 and related interrogatories. The significant decline in discount rates reflects the impact of financial market conditions on long-term bond rates. The decrease in the expected long-term rate of return reflects lower anticipated returns due to global financial market conditions. The 2013 and 2014 assumptions are outlined in further detail in reports from Aon Hewitt, filed in EB-2013-0321 (Ex. F4-3-1, Attachment 2 (2013) and Ex. N2-1-1, Attachment 1 (2014)). The same assumptions and inputs were used to derive the 2014 projected pension and OPEB

[8] Projections of rates of return to determine year-end pension fund asset values are not required for 2013 and 2014 costs because actual prior year-end asset values are known.

accrual costs reflected in the additions to the account as those underpinning the 2014 forecast accrual pension and OPEB costs included in OPG's proposed revenue requirement, as updated in Ex. N2-1-1, in EB-2013-0321.

The 2014 costs presented in Ex. H1-1-1, Tables 8 and 8a reflect the final assumptions as at December 31, 2013 and are expected to be close to the actual costs, absent any significant unexpected changes in legislation or OPG's operations. In conjunction with the audited account balances, OPG intends to file a separate independent actuary's report in support of the final 2013 and 2014 pension and OPEB amounts.

The projected year-end 2014 balance in the account also includes $225.2M ($10.5M for previously regulated hydroelectric and $214.7M for nuclear) as the unamortized portion of the Future Recovery component of the approved 2012 balances.

The Historic Recovery component of the approved December 31, 2012 balance will be fully amortized by December 31, 2014 through the payment riders established in EB-2012-0002, with any remaining balance transferred to Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and the Nuclear Deferral and Variance Over/Under Recovery Variance Account.

As ordered in EB-2012-0002 and EB-2013-0321, interest is not recorded on the Future Recovery and the 2013/2014 additions components of the variance account beginning on January 1, 2013.

5.9 Impact for USGAAP Deferral Account

Established in EB-2011-0432, this account captured the financial impacts on the prescribed facilities of OPG's transition to and implementation of USGAAP for the period from January 1, 2012 to December 31, 2012. This account records only interest and amortization effective January 1, 2013 and, pursuant to the EB-2013-0321 Payment Amounts Order, will be terminated at the end of the approved recovery period on December 31, 2014. Interest of $0.2M is projected to be recorded in the account during 2014. At the end of the 2014, the remaining unamortized balances in this account ($0.1M for hydroelectric and $0.8M for nuclear) will be transferred to the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and Nuclear Deferral and Variance Over/Under Recovery Variance Account, respectively as shown in Ex. H1-1-1 Table 1c.

5.10 Hydroelectric Deferral and Variance Over/Under Recovery Variance Account

This account records the differences between the amounts approved for recovery in the hydroelectric deferral and variance accounts and the actual amounts recovered based on the actual regulated hydroelectric production and approved riders. Pursuant to OEB's orders, the account also captures the transfer of the hydroelectric portions of the balances remaining in other accounts as they expire from time to time. The derivation of the debit entries of $2.9M in 2013 (actual) and $0.2M in 2014 (projected) is shown in Ex. H1-1-1, Table 9. There were no transfers from expiring accounts in 2013. As discussed above, there are projected transfers totaling $0.6M into this account from the Tax Loss Variance Account and Impact for USGAAP Deferral Account, both of which expire on December 31, 2014. These transfers are shown in Ex. H1-1-1, Table 1c.

5.11 Nuclear Liability Deferral Account

In accordance with section 5.2(1) of O. Reg. 53/05, this account records the revenue requirement impact on the prescribed facilities of any change in OPG's nuclear decommissioning and used fuel and waste management liabilities arising from an approved reference plan under the Ontario Nuclear Funds Agreement ("ONFA").

The account additions of $122.7M for 2013 and $82.2M for January through October 2014 relate to changes in the above liabilities arising from the current approved ONFA Reference Plan effective January 1, 2012. The derivation of these additions is shown at Ex. H1-1-1, Table 10. These additions have been made in accordance with the OEB's order in EB-2012-0002 using the same methodology as the additions in the approved December 31, 2012 account balance. The derivation of the 2013 additions is as described in EB-2013-0321, Ex. C2-1-1, section 4.1, and the 2014 additions are calculated in the same manner. The impact of the current approved ONFA Reference Plan on the prescribed facilities was discussed in EB-2013-0321, Ex. C2-1-1 and EB-2012-0002, Ex. H2-1-1.

OPG is not projecting any additions into the account in November and December 2014, as the EB-2013-0321 payment amounts reflect the impacts of the current approved ONFA Reference Plan.

In EB-2012-0002, $81.4M of the OEB-approved December 31, 2012 account balance was deferred for future recovery.[9] As such, this amount continues to be reflected in the account balance during 2013 and 2014, along with the additions made in 2013 and the first ten months of 2014. The projected account balance at December 31, 2014 is a debit of $286.3M, as shown in Ex. H1-1-1 Table 1. As ordered in EB-2012-0002 and EB-2013-0321, OPG is not recording any interest on the balance in this account effective January 1, 2013.

5.12 Nuclear Development Variance Account

The Nuclear Development Variance Account was established in accordance with section 5.4 of O. Reg. 53/05. This account records variances between the actual non-capital costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities and those forecast costs and firm financial commitments reflected in the revenue requirement approved by the OEB.

In EB-2012-0002, the OEB approved the deferral of the clearance of this account to EB-2013-0321 where the OEB approved clearance of the December 31, 2013 audited balance of $56.5M. This amount will be recovered as part of the EB-2013-0321 nuclear payment rider over 2015.

The December 31, 2014 balance in this account is projected to be a debit of $59M, as shown in Ex. H1-1-1, Table 1. This balance includes projected 2014 nuclear development costs of $1.6M shown in Ex. H1-1-1, Table 11. These amounts are being incurred by OPG to fulfill Provincial direction in the 2013 Ontario's Long-term Energy Plan to maintain the licence

[9] EB-2012-0002 Payment Amounts Order, App. A, Table 2, line 1, col. (d)

granted by the Canadian Nuclear Safety Commission, which preserves the option of considering New Nuclear in the future. The full amount of incurred costs is recorded in the account because the EB-2012-0002 and EB-2013-0321 payment amounts did not include a forecast of these costs. Interest of $0.8M is also projected in this account over 2014.

5.13 Bruce Lease Net Revenues Variance Account

This account continues to record differences between (i) the forecast revenues and costs related to the Bruce lease that are factored into the nuclear revenue requirement approved by the OEB, and (ii) OPG's actual revenues and costs for the Bruce facilities. A detailed discussion of these revenues and costs can be found in EB 2013-0321, Ex. G2-2-1 and EB-2012-0002, Ex. H2-1-2.

Pursuant to the EB-2012-0002 Payment Amounts Order, this account was divided into two sub-accounts as discussed below, and OPG has not recorded interest on either sub-account balance during 2013 and 2014 (with the exception of an interest credit to ratepayers related to the EB-2012-0002 calculation error discussed below).

Derivative Sub-Account

The Derivative Sub-Account captures impacts related to the derivative liability for the conditional partial supplemental rent rebate provision of the Bruce lease ("Bruce Derivative") (including associated income tax impacts on Bruce lease net revenues calculated in accordance with generally accepted accounting principles for unregulated entities) and the rent rebates associated with supplemental rent revenue. As discussed in EB-2013-0321, EB-2012-0002 and EB-2010-0008, a provision in the Bruce lease agreement requires OPG to provide a partial rebate to Bruce Power of the supplemental rent payments for certain Bruce units in a calendar year where the annual arithmetic average of the HOEP ("Average HOEP") falls below $30/MWh.

As shown in Ex. H1-1-1, Table 1a, $24.6M was added to the Derivative Sub-account in 2013. This addition was due to an increase in the fair value of the Bruce Derivative liability due to an increases in the probability-weighted average expectation of future Average HOEP falling below $30/MWh. A credit addition to the sub-account of $57.5M for January through to October 2014 is due to decreases in the probability-weighted average expectation of future Average HOEP falling below $30/MWh. As in EB-2010-0008 and EB-2013-0321, OPG has not forecast future changes in the fair value of the derivative, resulting in a projected addition of zero for November and December 2014 in Ex. H1-1-1 Table 1c.

Pursuant EB-2012-0002, the 2013 and 2014 amortization of the Derivative Sub-Account is equal to the amount of the supplemental rent rebate forecast to be payable to Bruce Power for each year by OPG and associated income tax impacts, adjusted by the difference between amounts previously recovered for the derivative, and the actual rent rebates paid by OPG to Bruce Power and associated income taxes.[10] OPG's proposal to continue with this recovery methodology is discussed in Ex. H1-2-1.

As noted in OPG's letter to the OEB dated September 26, 2013 and EB-2013-0321, Ex. H1-1-1, in preparing the EB-2013-0321 application, OPG identified an error made in the calculation of the 2013 amortization authorized in EB-2012-0002. As proposed in OPG's letter, the error is being corrected as part of the disposition of the balance of the Derivative Sub-Account in this application, by reducing the amount otherwise recoverable from ratepayers for the sub-account by $8.9M as shown in Ex. H1-1-1, Table 13c. This amount includes an interest credit to ratepayers, at the OEB-prescribed rate, for 2013 and 2014.

<u>Non-Derivative Sub-Account</u>

The Non-Derivative Sub-Account captures variances in non-derivative elements of the Bruce lease net revenues, including the cost impact of any changes in OPG's liability for decommissioning the Bruce nuclear generating facilities and the management of nuclear waste and nuclear fuel related to the Bruce stations.

Pursuant to EB-2012-0002, variances recorded in the account are measured against the amount of Bruce lease revenues net of costs credited to customers, determined by

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[10] As discussed in EB-2012-0002 Ex. M1-1, pp. 15-17, up to December 31, 2012, OPG recovered the impacts of the supplemental rent rebate provision as determined on the basis of generally accepted accounting principles (i.e., as changes in the fair value of the derivative liability rather than amounts of rebate payable).

multiplying the rate of recovery reflected in the EB-2010-0008 nuclear revenue requirement by OPG's actual nuclear production. The rate of recovery of $2.66/MWh was used in deriving the 2013 and January through October 2014 additions to the account. Pursuant to the EB-2013-0321 Decision, a rate of recovery of $0.84/MWh is used to calculate the projected November and December 2014 additions as shown in Ex. H1-1-1, Table 13.

The derivation of the 2013 and 2014 debit entries of $85.9M of $40.8M, respectively, to the Non-Derivative Sub-Account is shown in Ex. H1-1-1, Table 13. The additions relate primarily to the impacts of the current approved ONFA Reference Plan effective January 1, 2012, partially offset by higher earnings on the nuclear segregated funds than was reflected in the EB-2010-0008 forecasts. In 2013 and January through October 2014, there are also largely offsetting variances in supplemental rent revenue, which is higher than forecast in EB-2010-0008 due to CPI-based annual increases and the beginning of commercial operation of the refurbished Bruce A Units 1 and 2, and revenue for low and intermediate level waste management services, which is lower than forecast in EB-2010-0008 due to lower volumes of waste received from Bruce Power.

For November and December 2014, adjustments are made to the Non-Derivative Sub-Account to ensure that amounts recorded in the sub-account do not include those that OPG indicated it is not seeking to recover from, or refund to, ratepayers as part of the differences between the revenue requirement in its pre-filed evidence in EB-2013-0321, dated September 27, 2013, and the information based on OPG's 2014-2016 Business Plan. This adjustment is shown in Ex. H1-1-1, Table 13, line 8.

5.14 Pickering Life Extension Depreciation Variance Account

This variance account was established in EB-2012-0002 to record a credit amount of $3.9M per month for the period from January 1, 2013 until the effective of payment amounts that reflect the revised service lives, for depreciation purposes, of the Pickering station.[11] In that proceeding, the nuclear payment riders established for 2013 and 2014 were reduced by an

[11] The impact of the revised accounting service lives for Pickering on the test period depreciation expense was discussed in EB-2013-0321 Ex. F4-1-1, section 3.3.

equivalent amount, resulting in a debit amortization amount being recorded in this account starting in 2013. As the EB-2013-0321 payment amounts are effective November 1, 2014 and reflect the revised service lives of the Pickering station, additions to the account cease after October 31, 2014 pursuant to the EB-2013-0321 Payment Amounts Order.

As the EB-2012-0002 payment rider continues until December 31, 2014, the account continues to record an amortization debit entry during 2014. This results in an accumulation, by December 31, 2014, of a balance to be recovered from ratepayers of $7.8M, as shown in Ex. H1-1-1, Table 1. This operation of the account is outlined in the approved EB-2012-0002 Settlement Agreement (Ex. M1-1, p. 30) and avoids the double-counting of the impact of the revised service lives that would otherwise result once the EB-2013-0321 payment amounts come into effect.

OPG proposes to completely amortize the December 31, 2014 account balance by December 31, 2016, and to terminate this account at that time.

Pursuant to EB-2012-0002 and EB-2013-0321, no interest is recorded on the balance of the account.

5.15 Nuclear Deferral and Variance Over/Under Recovery Variance Account

This account records the differences between the amounts approved for recovery in the nuclear deferral and variance accounts and the actual amounts recovered based on the actual nuclear production and approved riders. Pursuant to the OEB's orders, the account also captures the transfer of the nuclear portions of the balances remaining in other accounts as they expire from time to time. The derivation of the 2013 account additions of $39.5M and the projected 2014 additions of $12.7M is shown in Ex. H1-1-1, Table 14. There were no transfers from expiring accounts in 2013. Transfers from the nuclear portions of the Tax Loss Variance Account and Impact for USGAAP Deferral Account, both of which expire December 31, 2014, are projected to total $3.9M and are shown in Ex. H1-1-1, Table 1c.

Numbers may not add due to rounding.

Table 1
Deferral and Variance Accounts
Closing Account Balances - 2012 to 2014 ($M)

Line No.	Account	EB-2012-0002 Year End Balance 2012[1]	Actual Year End Balance 2013[2]	Projected Year End Balance 2014[3]
		(a)	(b)	(c)
	Regulated Hydroelectric:			
1	**Hydroelectric Water Conditions Variance**	17.1	22.4	12.7
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	34.0	15.8	(10.6)
3	**Hydroelectric Incentive Mechanism Variance**	(2.4)	(5.0)	(7.5)
4	**Hydroelectric Surplus Baseload Generation Variance**	4.1	19.2	52.0
5	**Income and Other Taxes Variance - Hydroelectric**	(2.5)	(1.1)	(0.1)
6	**Tax Loss Variance - Hydroelectric**	48.2	19.7	0.0
7	**Capacity Refurbishment Variance - Hydroelectric**	1.1	112.7	232.6
8	**Gross Revenue Charge Variance**	N/A	N/A	0.0
9	**Pension and OPEB Cost Variance - Hydroelectric - Historic**	2.5	1.0	0.0
10	**Pension and OPEB Cost Variance - Hydroelectric - Future**	12.6	11.3	10.5
11	**Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions**	N/A	18.6	35.5
12	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric**	N/A	N/A	9.2
13	**Pension & OPEB Cash Payment Variance - Hydroelectric**	N/A	N/A	(0.9)
14	**Impact for USGAAP Deferral - Hydroelectric**	2.8	1.2	0.0
15	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(3.9)	1.3	3.7
16	**Total**	113.8	217.3	337.1
	Nuclear:			
17	**Nuclear Liability Deferral**	206.2	254.0	286.3
18	**Nuclear Development Variance**	30.2	56.5	59.0
19	**Ancillary Services Net Revenue Variance - Nuclear**	1.7	1.9	1.7
20	**Capacity Refurbishment Variance - Nuclear - Capital Portion**	1.3	5.7	13.1
21	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**	11.8	8.9	6.7
22	**Bruce Lease Net Revenues Variance - Derivative Sub-Account**	230.3	214.4	129.9
23	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002**	74.8	52.3	37.3
24	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions**	N/A	85.9	126.8
25	**Income and Other Taxes Variance - Nuclear**	(32.5)	(17.9)	(8.5)
26	**Tax Loss Variance - Nuclear**	253.3	103.8	0.0
27	**Pension and OPEB Cost Variance - Nuclear - Historic**	51.5	20.7	0.0
28	**Pension and OPEB Cost Variance - Nuclear - Future**	257.6	231.8	214.7
29	**Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions**	N/A	383.7	678.6
30	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear**	N/A	N/A	62.0
31	**Pension & OPEB Cash Payment Variance - Nuclear**	N/A	N/A	(0.8)
32	**Impact for USGAAP Deferral - Nuclear**	60.3	24.7	0.0
33	**Pickering Life Extension Depreciation Variance**	N/A	9.5	7.8
34	**Nuclear Deferral and Variance Over/Under Recovery Variance**	6.9	42.6	57.4
35	**Total**	1,153.3	1,478.5	1,671.9
36	**Grand Total** (line 16 + line 35)	1,267.1	1,695.8	2,009.0

Notes:
1 From Ex. H1-1-1, Table 1a, col. (c).
2 From Ex. H1-1-1, Table 1a, col. (h).
3 From Ex. H1-1-1, Table 1c, col. (f).

Table 1a
Deferral and Variance Accounts
Continuity of Account Balances - 2012 to 2013 ($M)

Line No.	Account	Audited Year End Balance 2012[1]	EB-2012-0002 Negotiated Reductions[2]	(a)+(b) EB-2012-0002 Year End Balance 2012[3]	Actual 2013 Transactions[4]	Actual 2013 Amortization[4,5]	Actual 2013 Interest[4,5]	Actual 2013 Transfers[5]	(c)+(d)+(e)+(f)+(g) Actual Year End Balance 2013 [5]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Previously Regulated Hydroelectric:								
1	**Hydroelectric Water Conditions Variance**	17.1	0.0	17.1	15.2	(10.3)	0.4	0.0	22.4
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	34.0	0.0	34.0	1.8	(20.4)	0.4	0.0	15.8
3	**Hydroelectric Incentive Mechanism Variance**	(2.4)	0.0	(2.4)	(2.5)	0.0	(0.0)	0.0	(5.0)
4	**Hydroelectric Surplus Baseload Generation Variance**	4.1	0.0	4.1	14.9	0.0	0.1	0.0	19.2
5	**Income and Other Taxes Variance - Hydroelectric**	(2.5)	0.0	(2.5)	(0.1)	1.5	(0.0)	0.0	(1.1)
6	**Tax Loss Variance - Hydroelectric**	48.2	0.0	48.2	0.0	(28.9)	0.5	0.0	19.7
7	**Capacity Refurbishment Variance - Hydroelectric**	1.1	0.0	1.1	111.1	0.0	0.5	0.0	112.7
8	**Pension and OPEB Cost Variance - Hydroelectric - Historic**	2.5	0.0	2.5	0.0	(1.5)	0.0	0.0	1.0
9	**Pension and OPEB Cost Variance - Hydroelectric - Future**	12.6	0.0	12.6	0.0	(1.3)	0.0	0.0	11.3
10	**Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions**	N/A	N/A	N/A	18.6	N/A	0.0	0.0	18.6
11	**Impact for USGAAP Deferral - Hydroelectric**	2.8	0.0	2.8	0.0	(1.7)	0.0	0.0	1.2
12	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(3.9)	0.0	(3.9)	2.9	2.3	(0.0)	0.0	1.3
13	**Total**	113.8	0.0	113.8	162.0	(60.3)	1.8	0.0	217.3
	Nuclear:								
14	**Nuclear Liability Deferral**	208.0	(1.8)	206.2	122.7	(74.9)	0.0	0.0	254.0
15	**Nuclear Development Variance**	30.2	0.0	30.2	25.6	0.0	0.7	0.0	56.5
16	**Ancillary Services Net Revenue Variance - Nuclear**	1.7	0.0	1.7	1.2	(1.0)	0.0	0.0	1.9
17	**Capacity Refurbishment Variance - Nuclear - Capital Portion**	1.3	0.0	1.3	4.3	0.0	0.0	0.0	5.7
18	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**	11.8	0.0	11.8	4.0	(7.1)	0.1	0.0	8.9
19	**Bruce Lease Net Revenues Variance - Derivative Sub-Account**	230.3	0.0	230.3	24.6	(40.5)	(0.0)	0.0	214.4
20	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002**	80.2	(5.5)	74.8	0.0	(22.4)	0.0	0.0	52.3
21	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions**	N/A	N/A	N/A	85.9	0.0	0.0	0.0	85.9
22	**Income and Other Taxes Variance - Nuclear**	(32.5)	0.0	(32.5)	(4.5)	19.5	(0.3)	0.0	(17.9)
23	**Tax Loss Variance - Nuclear**	253.3	0.0	253.3	0.0	(152.0)	2.5	0.0	103.8
24	**Pension and OPEB Cost Variance - Nuclear - Historic**	51.5	0.0	51.5	0.0	(31.4)	0.5	0.0	20.7
25	**Pension and OPEB Cost Variance - Nuclear - Future**	257.6	0.0	257.6	0.0	(25.8)	0.0	0.0	231.8
26	**Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions**	N/A	N/A	N/A	383.7	N/A	0.0	0.0	383.7
27	**Impact for USGAAP Deferral - Nuclear**	60.3	0.0	60.3	0.0	(36.2)	0.6	0.0	24.7
28	**Pickering Life Extension Depreciation Variance**[7]	N/A	N/A	N/A	(46.8)	56.3	0.0	0.0	9.5
29	**Nuclear Deferral and Variance Over/Under Recovery Variance**	6.9	0.0	6.9	39.5	(4.2)	0.3	0.0	42.6
30	**Total**	1,160.6	(7.3)	1,153.3	640.2	(319.5)	4.4	0.0	1,478.5
31	**Grand Total** (line 13 + line 29)	1,274.4	(7.3)	1,267.1	802.2	(379.8)	6.2	0.0	1,695.8

Notes:
1. From EB-2012-0002 Payment Amounts Order, App. A, Table 1 col. (a) for previously regulated hydroelectric and Table 2 col. (a) for nuclear.
2. From EB-2012-0002 Payment Amounts Order, App. A, Table 1 col. (b) for regulated hydroelectric and Table 2 col. (b) for nuclear.
3. From EB-2012-0002 Payment Amounts Order, App. A, Table 1 col. (c) for previously regulated hydroelectric and Table 2 col. (c) for nuclear. With the exception of balances at lines 3, 4, 7, 10, 15, 17, 21, 26 and 28, all balances were approved by the OEB in EB-2012-0002 (Payment Amounts Order, App. B, Table B-1, col. (a)).
4. From EB-2013-0321 Ex. L-9.1-17 SEC-132 (corrected version filed on June 4, 2014), Attachment 1, Table 1
5. From the EB-2012-0002 Payment Amounts Order, App. B, Table B-1, col. (c).
6. Effective January 1, 2013, per the EB-2012-0002 Payments Amount Order, no interest is recorded on the balance of Nuclear Liability Deferral Account. Effective January 1, 2013, per the EB-2012-0002 and EB-2013-0321 Payment Amounts Orders, no interest is recorded on the balances of the Bruce Lease Net Revenues Variance Account and the Pension and OPEB Cost Variance Account excluding the Historic Recovery component. Line 19 includes an interest credit related to the inadvertent overstatement in the EB-2012-0002 Payment Amounts Order and related Settlement Agreement of the amount recoverable in 2013 and 2014 for the Bruce Lease Net Revenues Derivative Sub-Account, as noted in EB-2013-0321, Ex. H1-1-1, section 4.13 and OPG's letter to the OEB dated September 26, 2013 referenced therein.
7. Per the EB-2012-0002 and EB-2013-0321 Payment Amounts Orders, for the period from January 1, 2013 to October 31, 2014, the account reflects a credit of $3.9M per month to ratepayers for the benefit of lower non-asset retirement costs depreciation expense and associated income tax impacts resulting from the revision of the Pickering generation stations' service lives, as discussed in Ex. H1-1-1 section 5.14. Per these OEB orders, no interest is recorded in this account.

Numbers may not add due to rounding.

Table 1b
Deferral and Variance Accounts
Continuity of Account Balances - January to October 2014 ($M)

Line No.	Account	Actual Year End Balance 2013[1]	Current Activity January 1 to October 31, 2014 Transactions	Amortization[2]	Interest[3]	Transfers	(a)+(b)+(c)+(d)+(e) Current Balance October 31, 2014
		(a)	(b)	(c)	(d)	(e)	(f)
	Previously Regulated Hydroelectric:						
1	**Hydroelectric Water Conditions Variance**	22.4	(1.7)	(5.7)	0.2	0.0	15.2
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	15.8	(12.1)	(11.3)	0.0	0.0	(7.6)
3	**Hydroelectric Incentive Mechanism Variance**	(5.0)	(2.4)	0.0	(0.1)	0.0	(7.5)
4	**Hydroelectric Surplus Baseload Generation Variance**	19.2	22.7	0.0	0.3	0.0	42.2
5	**Income and Other Taxes Variance - Hydroelectric**	(1.1)	(0.0)	0.8	(0.0)	0.0	(0.3)
6	**Tax Loss Variance - Hydroelectric**	19.7	0.0	(16.1)	0.1	0.0	3.7
7	**Capacity Refurbishment Variance - Hydroelectric**	112.7	117.4	0.0	2.0	0.0	232.1
8	**Pension and OPEB Cost Variance - Hydroelectric - Historic**	1.0	0.0	(0.9)	0.0	0.0	0.2
9	**Pension and OPEB Cost Variance - Hydroelectric - Future**	11.3	0.0	(0.7)	0.0	0.0	10.6
10	**Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions**	18.6	16.8	N/A	0.0	0.0	35.5
11	**Impact for USGAAP Deferral - Hydroelectric**	1.2	0.0	(0.9)	0.0	0.0	0.3
12	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	1.3	0.6	1.3	0.0	0.0	3.2
13	**Total**	217.3	141.2	(33.5)	2.5	0.0	327.6
	Nuclear:						
14	**Nuclear Liability Deferral**	254.0	82.2	(41.6)	0.0	0.0	294.6
15	**Nuclear Development Variance**	56.5	1.2	0.0	0.7	0.0	58.5
16	**Ancillary Services Net Revenue Variance - Nuclear**	1.9	0.3	(0.6)	0.0	0.0	1.7
17	**Capacity Refurbishment Variance - Nuclear - Capital Portion**	5.7	6.3	0.0	0.1	0.0	12.0
18	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**	8.9	(2.4)	(3.9)	0.1	0.0	2.7
19	**Bruce Lease Net Revenues Variance - Derivative Sub-Account**	214.4	(57.5)	(22.5)	0.0	0.0	134.4
20	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002**	52.3	0.0	(12.5)	0.0	0.0	39.8
21	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions**	85.9	41.1	0.0	0.0	0.0	127.0
22	**Income and Other Taxes Variance - Nuclear**	(17.9)	(3.4)	10.8	(0.1)	0.0	(10.6)
23	**Tax Loss Variance - Nuclear**	103.8	0.0	(84.4)	0.6	0.0	20.0
24	**Pension and OPEB Cost Variance - Nuclear - Historic**	20.7	0.0	(17.4)	0.1	0.0	3.4
25	**Pension and OPEB Cost Variance - Nuclear - Future**	231.8	0.0	(14.3)	0.0	0.0	217.5
26	**Pension and OPEB Cost Variance - Nuclear - post 2012 Additions**	383.7	294.9	N/A	0.0	0.0	678.6
27	**Impact for USGAAP Deferral - Nuclear**	24.7	0.0	(20.1)	0.2	0.0	4.8
28	**Pickering Life Extension Depreciation Variance[4]**	9.5	(39.0)	31.3	0.0	0.0	1.7
29	**Nuclear Deferral and Variance Over/Under Recovery Variance**	42.6	12.1	(2.3)	0.6	0.0	53.0
30	**Total**	1,478.5	335.7	(177.5)	2.4	0.0	1,639.0
31	**Grand Total** (line 13 + line 29)	1,695.8	476.9	(211.0)	5.0	0.0	1,966.6

Notes:
1 From Ex. H1-1-1, Table 1a, col. (h).
2 Calculated as 10/12 multiplied by EB-2012-0002 Payment Amounts Order, App. B, Table B-1, col. (d)
3 See Ex. H1-1-1, Table 1a, Note 6
4 See Ex. H1-1-1, Table 1a, Note 7

Numbers may not add due to rounding.

Table 1c
Deferral and Variance Accounts
Continuity of Account Balances - November and December 2014 ($M)

Line No.	Account	Current Balance October 31 2014[1]	Projected Activity November 1 to December 31, 2014 Transactions	Amortization[2]	Interest[3,4]	Transfers	(a)+(b)+(c)+(d)+(e) Projected Year End Balance 2014[7]
		(a)	(b)	(c)	(d)	(e)	(f)
	Regulated Hydroelectric (Previously and Newly Regulated Hydroelectric):						
1	**Hydroelectric Water Conditions Variance**	15.2	(1.4)	(1.1)	0.0	0.0	12.7
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	(7.6)	(0.7)	(2.3)	(0.0)	0.0	(10.6)
3	**Hydroelectric Incentive Mechanism Variance**	(7.5)	0.0	0.0	(0.0)	0.0	(7.5)
4	**Hydroelectric Surplus Baseload Generation Variance**	42.2	9.7	0.0	0.1	0.0	52.0
5	**Income and Other Taxes Variance - Hydroelectric**	(0.3)	0.0	0.2	(0.0)	0.0	(0.1)
6	**Tax Loss Variance - Hydroelectric**	3.7	0.0	(3.2)	0.0	(0.5)	0.0
7	**Capacity Refurbishment Variance - Hydroelectric**	232.1	0.0	0.0	0.6	0.0	232.6
8	**Gross Revenue Charge Variance**	0.0	0.0	0.0	0.0	0.0	0.0
9	**Pension and OPEB Cost Variance - Hydroelectric - Historic**	0.2	0.0	(0.2)	0.0	0.0	0.0
10	**Pension and OPEB Cost Variance - Hydroelectric - Future**	10.6	0.0	(0.1)	0.0	0.0	10.5
11	**Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions**	35.5	0.0	0.0	0.0	(0.0)	35.5
12	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric**	0.0	9.2	0.0	0.0	0.0	9.2
13	**Pension & OPEB Cash Payment Variance - Hydroelectric**	0.0	(0.9)	0.0	(0.0)	0.0	(0.9)
14	**Impact for USGAAP Deferral - Hydroelectric**	0.3	0.0	(0.2)	0.0	(0.1)	0.0
15	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	3.2	(0.4)	0.3	0.0	0.6	3.7
16	**Total**	327.6	15.6	(6.7)	0.6	0.0	337.1
	Nuclear:						
17	**Nuclear Liability Deferral**	294.6	0.0	(8.3)	0.0	0.0	286.3
18	**Nuclear Development Variance**	58.5	0.4	0.0	0.2	0.0	59.0
19	**Ancillary Services Net Revenue Variance - Nuclear**	1.7	0.1	(0.1)	0.0	0.0	1.7
20	**Capacity Refurbishment Variance - Nuclear - Capital Portion**	12.0	0.9	0.0	0.1	0.0	13.1
21	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**	2.7	4.8	(0.8)	0.0	0.0	6.7
22	**Bruce Lease Net Revenues Variance - Derivative Sub-Account**	134.4	0.0	(4.5)	0.0	0.0	129.9
23	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002**	39.8	0.0	(2.5)	0.0	0.0	37.3
24	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions**	127.0	(0.3)	0.0	0.0	0.0	126.8
25	**Income and Other Taxes Variance - Nuclear**	(10.6)	0.0	2.2	(0.0)	0.0	(8.5)
26	**Tax Loss Variance - Nuclear**	20.0	0.0	(16.9)	0.1	(3.2)	0.0
27	**Pension and OPEB Cost Variance - Nuclear - Historic**	3.4	0.0	(3.5)	0.1	(0.0)	0.0
28	**Pension and OPEB Cost Variance - Nuclear - Future**	217.5	0.0	(2.9)	0.0	0.0	214.7
29	**Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions**	678.6	0.0	0.0	0.0	0.0	678.6
30	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear**	0.0	62.0	0.0	0.0	0.0	62.0
31	**Pension & OPEB Cash Payment Variance - Nuclear**	0.0	(0.7)	0.0	(0.0)	0.0	(0.8)
32	**Impact for USGAAP Deferral - Nuclear**	4.8	0.0	(4.0)	0.0	(0.8)	0.0
33	**Pickering Life Extension Depreciation Variance[6]**	1.7	(0.0)	6.3	0.0	0.0	7.8
34	**Nuclear Deferral and Variance Over/Under Recovery Variance**	53.0	0.7	(0.5)	0.1	4.0	57.4
35	**Total**	1,639.0	67.8	(35.5)	0.7	0.0	1,671.9
36	**Grand Total** (line 16 + line 35)	1,966.6	83.4	(42.2)	1.3	0.0	2,009.0

Notes:
1 From Ex. H1-1-1, Table 1b, col. (f).
2 Calculated as the value from EB-2012-0002 Payment Amounts Order, App. B, Table B-1, col. (d), multiplied by 2/12.
3 See Ex. H1-1-1, Table 1a, Note 6.
4 Per the EB-2013-0321 Payment Amounts Order, no interest is recorded on the Pension & OPEB Cash Versus Accrual Differential Deferral Account.
5 In accordance with the EB-2013-0321 Payment Amounts Order, the Tax Loss Variance Account and the Impact for USGAAP Deferral Account will be terminated on December 31, 2014, with the remaining corresponding balances as of that date transferred to the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and the Nuclear Deferral and Variance Account. Similarly, in accordance with the EB-2013-0321 Payment Amounts Order, the remaining corresponding History Recovery balances of the Pension and OPEB Cost Variance Account at December 31, 2014 will be transferred to the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and the Nuclear Deferral and Variance Over/Under Recovery Variance Account.
6 See Ex. H1-1-1, Table 1a, Note 7.

Numbers may not add due to rounding.

Table 2
Hydroelectric Water Conditions Variance Account
Summary of Account Transactions - 2013 and 2014

Line No.	Particulars	Actual 2013[1]	Current Jan - Oct 2014	Projected Nov - Dec 2014	(b)+(c) Projected Total 2014
		(a)	(b)	(c)	(d)
	Previously Regulated Hydroelectric:				
1	**Forecast Production - EB-2012-0002 / EB-2013-0321[2] (GWh)**	19,831.9	15,483.6	3,282.0	18,765.6
2	**Actual / Projected Calculated Production (GWh)**	19,167.4	15,577.2	3,460.3	19,037.5
3	**Difference (GWh)** (line 1 - line 2)	664.5	(93.6)	(178.3)	(271.9)
4	**Payment Amount per EB-2010-0008 / EB-2013-0321 ($/MWh)[3]**	35.8	35.8	40.2	
5	**Revenue Impact ($M)** (line 3 x line 4 / 1000)	23.8	(3.3)	(7.2)	(10.5)
6	**GRC/Water Rental Costs ($M)**	(8.5)	1.7	2.6	4.2
7	**Addition to Variance Account ($M)** (line 5 + line 6)	15.2	(1.7)	(4.6)	(6.3)
	Newly Regulated Hydroelectric:				
8	**Forecast Production - EB-2013-0321[2,5] (GWh)**	N/A	N/A	2,056.9	2,056.9
9	**Projected Calculated Production[5] (GWh)**	N/A	N/A	1,962.3	1,962.3
10	**Difference (GWh)** (line 8 - line 9)			94.6	94.6
11	**Payment Amount per EB-2013-0321 ($/MWh)[4]**	N/A	N/A	41.93	
12	**Revenue Impact ($M)** (line 10 x line 11 / 1000)	N/A	N/A	4.0	4.0
13	**GRC/Water Rental Costs ($M)**	N/A	N/A	(0.8)	(0.8)
14	**Addition to Variance Account ($M)** (line 12 + line 13)	N/A	N/A	3.2	3.2
15	**Total Addition to Variance Account ($M)** (line 7 + line 14)	15.2	(1.7)	(1.4)	(3.1)

Notes:

1 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 2, col. (a).

2 2013 and January to October 2014 forecast production has been determined using the average monthly forecasts for 2011 and 2012 underpinning the reference amounts from EB-2010-0008 per EB-2012-0002 Payment Amounts Order, App. B, page 3. November to December 2014 forecast production is as reflected in the 2014 Board-approved production value, in accordance with the EB-2013-0321 Payment Amounts Order, App. G, p 3.

3 From EB-2010-0008 Payment Amounts Order, App. B, Table 1, line 3 for 2013 and January to October 2014. From EB-2013-0321 Payment Amounts Order, App. B, Table 1, line 3 for November to December 2014.

4 From EB-2013-0321 Payment Amounts Order, App. C, Table 1, line 3.

5 In accordance with the EB-2013-0321 Payment Amounts Order, App. G, pp. 2-3, the value represents production for the 21 newly regulated hydroelectric facilities subject to the variance account.

Table 3
Ancillary Services Net Revenue Variance Account
Summary of Account Transactions - 2013 and 2014 ($M)

Line No.	Particulars	Actual 2013[1]	Current Jan - Oct 2014	Projected Nov - Dec 2014	(b)+(c) Projected Total 2014
		(a)	(b)	(c)	(d)
	Previously Regulated Hydroelectric:				
1	**Forecast Revenue - EB-2012-0002 / EB-2013-0321**[2]	38.9	32.4	5.4	37.8
2	**Actual / Projected Revenue**	37.1	44.5	6.3	50.8
3	**Addition to Variance Account** (line 1 - line 2)	1.8	(12.1)	(0.8)	(12.9)
	Newly Regulated Hydroelectric:				
4	**Forecast Revenue - EB-2013-0321**[3]	N/A	N/A	3.8	3.8
5	**Projected Revenue**	N/A	N/A	4.4	4.4
6	**Addition to Variance Account Before Adjustment** (line 4 - line 5)	N/A	N/A	(0.6)	(0.6)
7	**Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment**[4]	N/A	N/A	(0.8)	(0.8)
8	**Addition to Variance Account** (line 6 - line 7)	N/A	N/A	0.2	0.2
9	**Hydroelectric Addition to Variance Account** (line 3 + line 8)	N/A	N/A	(0.7)	(12.8)
	Nuclear:				
10	**Forecast Revenue - EB-2012-0002 / EB-2013-0321**[5]	3.0	2.5	0.3	2.8
11	**Actual / Projected Revenue**	1.7	2.1	0.3	2.4
12	**Addition to Variance Account Before Adjustment** (line 10 - line 11)	1.2	0.3	0.0	0.3
13	**Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment**[4]	N/A	N/A	(0.1)	(0.1)
14	**Nuclear Addition to Variance Account** (line 12 - line 13)	1.2	0.3	0.1	0.4

Notes:
1 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 3.
2 2013 value is $3.24M/month x 12 months per EB-2012-0002 Payment Amounts Order, App. B, page 4. January to October 2014 value is $3.24M/month x 10 months per EB-2012-0002 Payment Amounts Order, App. B, page 4. November to December 2014: $2.71M/month x 2 months per EB-2013-0321 Payment Amounts Order, App. G, page 4.
3 Calculated as $1.91M/month x 2 months per EB-2013-0321 Payment Amounts Order, App. G, page 4.
4 The adjustments are per the EB-2013-0321 Payment Amounts Order (App. G, p. 4) requirement that amounts recorded in the account do not include those that OPG indicated it is not seeking to recover from, or refund to, ratepayers as part of the differences between the revenue requirement in its EB-2013-0321 pre-filed evidence and the information based on OPG's 2014-2016 Business Plan, which was provided in the EB-2013-0321 Impact Statement at Ex. N1. The total of the adjustments represent a 2-month portion of the $8M test period increase (EB-2013-0321 Ex. N1-1-1, Chart 1) in forecast newly regulated hydroelectric and nuclear ancillary services net revenues between OPG's EB-2013-0321 pre-filed evidence and its 2014-2016 Business Plan. This difference was not included in the updated revenue requirement in the Ex. N1 impact statement. The monthly adjustment amount for newly regulated hydroelectric and nuclear is calculated below. No adjustment is necessary for the previously regulated hydroelectric ancillary services net revenue since, as discussed in section 2.4 of EB-2013-0321 Ex. N1-1-1, the revenue requirement was updated for the 2014-2016 Business Plan values.

Table to Note 4 - Monthly EB-2013-0321 (Ex. N1) Impact Statement Adjustments ($M)

Line No.	Particulars	2014[#]	2015	Total
		(a)	(b)	(c)
	Newly Regulated Hydroelectric:			
1a	Forecast Revenue - EB-2013-0321 OPG's Pre-filed Evidence[##]	11.3	23.1	34.4
2a	Forecast Revenue - OPG's 2014-2016 Business Plan	13.6	27.8	41.4
3a	Difference (line 1a - line 2a)	(2.3)	(4.7)	(7.0)
4a	Monthly EB-2013-0321 Impact Statement (Ex. N1) Adjustment (line 3a / 18 months)			(0.4)
	Nuclear:			
5a	Forecast Revenue - EB-2013-0321 Pre-filed Evidence[+]	1.9	1.9	3.8
6a	Forecast Revenue - 2014-2016 Business Plan	2.4	2.5	4.9
7a	Difference (line 4a - line 5a)	(0.55)	(0.56)	(1.11)
8a	Monthly EB-2013-0321 Impact Statement (Ex. N1) Adjustment (line 7a / 24 months)			(0.05)

\# Newly regulated hydroelectric values are for the 6-month period from July 1, 2014 to December 31, 2014.
\## From EB-2013-0321 Ex. G1-1-1 Table 1, line 6: 2014 value is col. (e) multiplied by 6/12, and 2015 value is from col. (f).
\+ From EB-2013-0321 Ex. G2-1-1 Table 1, line 8, cols. (e) and (f).

5 2013 value is $0.25M/month x 12 months per EB-2012-0002 Payment Amounts Order, App. B, page 10.
January to October 2014 value is $0.25M/month x 10 months per EB-2012-0002 Payment Amounts Order, App. B, page 10.
November to December 2014 value is $0.14M/month x 2 months per EB-2013-0321 Payment Amounts Order, App. G, page 10.

Table 4
Hydroelectric Incentive Mechanism Variance Account
Summary of Account Transactions - 2014 ($M)

Line No.	Particulars	Current Jan - Oct 2014	Projected Nov - Dec 2014	(a)+(b) Projected Total 2014
		(a)	(b)	(c)
1	**Actual / Projected Previously Regulated Hydroelectric Incentive Mechanism Net Revenue**	15.7	2.8	18.6
2	**Projected Newly Regulated Hydroelectric Incentive Mechanism Net Revenue**	N/A	2.7	2.7
3	**Total Actual / Projected Regulated Hydroelectric Incentive Mechanism Revenue**	15.7	5.6	21.3
4	**Threshold per EB-2012-0002 / EB-2013-0321** [1]	10.8	8.5	19.3
5	**Actual / Projected Hydroelectric Incentive Mechanism Net Revenue In Excess of Threshold** (line 3 - line 4; nil if line 3 < line 4)	4.9	0.0	4.9
6	**Percentage** [2]	50%	50%	50%
7	**Addition to Variance Account** (line 5 x line 6)	(2.4)	0.0	(2.4)

Notes:
1 January to October 2014 threshold from EB-2012-0002 Payment Amounts Order, App. B, page 8, multiplied by 10/12.
November to December 2014 threshold from EB-2013-0321 Payment Amounts Order, App. G, page 7.
2 January to October 2014 percentage from EB-2012-0002 Payment Amounts Order, App. B, page 8.
November to December 2014 percentage from EB-2013-0321 Payment Amounts Order, App. G, page 7.

Table 5
Hydroelectric Surplus Baseload Generation Variance Account
Summary of Account Transactions - 2014

Line No.	Particulars	Current Jan - Oct 2014	Projected Nov - Dec 2014	(a)+(b) Projected Total 2014
		(a)	(b)	(c)
	Previously Regulated Hydroelectric:			
1	**Actual / Projected Foregone Production Due to SBG Conditions (GWh)**[1]	1,060.9	169.3	1,230.3
2	**Payment Amount per EB-2010-0008 / EB-2013-0321 ($/MWh)**[2]	35.78	40.20	
3	**Revenue ($M)** (line 1 x line 2 / 1000)	38.0	6.8	44.8
4	**GRC/Water Rental Costs ($M)**	(15.3)	(2.4)	(17.7)
5	**Addition to Variance Account ($M) (line 3 + line 4)**	22.7	4.4	27.1
	Newly Regulated Hydroelectric:			
6	**Projected Foregone Production Due to SBG Conditions (GWh)**	N/A	175.4	175.4
7	**Payment Amount per EB-2013-0321 ($/MWh)**[3]	N/A	41.93	
8	**Revenue ($M)** (line 6 x line 7 / 1000)	N/A	7.4	7.4
9	**GRC/Water Rental Costs ($M)**	N/A	(2.0)	(2.0)
10	**Addition to Variance Account ($M)** (line 8 + line 9)		5.4	5.4
11	**Total Addition to Variance Account ($M)** (line 5 + line 10)	N/A	9.7	32.4

Notes:

1 Includes an upward adjustment of 29.7 GWh to the 2013 estimated foregone production reflected in the EB-2013-0321 Board-approved account balance, reflecting a refinement to OPG's spill reporting methodology in 2014 based on an accumulation of data since the new Niagara Tunnel was placed in service in March 2013.

2 From EB-2010-0008 Payment Amounts Order, App. B, Table 1 for 2013 and January to October 2014.
From EB-2013-0321 Payment Amounts Order, App. B, Table 1, line 3 for November to December 2014.

3 From EB-2013-0321 Payment Amounts Order, App. C, Table 1, line 3.

Numbers may not add due to rounding.

Table 6
Income and Other Taxes Variance Account
Summary of Account Transactions - 2013 and 2014 ($M)

Line No.	Particulars	Note	Actual 2013[1] Previously Regulated Hydroelectric	Actual 2013[1] Nuclear	Actual 2013[1] Total	Current Activity Jan to Oct 2014 Previously Regulated Hydroelectric	Current Activity Jan to Oct 2014 Nuclear	Current Activity Jan to Oct 2014 Total
			(a)	(b)	(c)	(d)	(e)	(f)
	Entry (i): Increase of Scientific Research and Experimental Development ("SR&ED") Investment Tax Credits (ITCs) Recognition Percentage from 50% to 75%							
1	**Forecast SR&ED ITCs, net of Tax on ITCs, at 50%**	2	(0.1)	(6.5)	(6.6)	(0.1)	(6.5)	(6.6)
2	**Forecast SR&ED ITCs, net of Tax on ITCs, at 75%** (line 1 x 3/2)		(0.1)	(9.8)	(9.9)	(0.1)	(9.8)	(9.9)
3	**Addition to Variance Account - SR&ED ITCs Recognition Percentage Increase** (cols. (a) to (c): line 2 - line 1; cols. (d) to (f): (line 2 - line 1) x 10/12)		(0.0)	(3.3)	(3.3)	(0.0)	(2.7)	(2.7)
	Entry (ii): Reduction in Contractor Payments Qualifying for SR&ED ITCs from 100% to 80%							
4	**Annual Qualifying Contractor Payments Reflected in Forecast SR&ED ITCs**		0.6	57.4	58.0	0.6	57.4	58.0
5	**20% Portion Not Eligible for SR&ED ITCs** (line 4 x 20%)		0.1	11.5	11.6	0.1	11.5	11.6
6	**Investment Tax Credit Rate**		0.2	0.2	0.2	0.2	0.2	0.2
7	**Reduction in SR&ED ITCs** (cols (a) to (c): line 5 x line 6; cols (d) to (f): line 5 x line 6 x 10/12)		0.0	2.3	2.3	0.0	1.4	1.5
8	**Tax on 2013 Reduction in SR&ED ITCs**		0.0	0.0	0.0	0.0	0.4	0.4
9	**Addition to Variance Account - Reduction in Contractor Payments Qualifying for SR&ED ITCs** ((line 7 - line 8) x 75% SR&ED ITC recognition percentage)		0.0	1.7	1.7	0.0	0.8	0.8
	Entry (iii): Income Tax Variance Due to Nuclear Waste Management Capital Expenditures Adjustment							
10	**Non-Deductible Portion of Cash Expenditures for Nuclear Waste & Decommissioning**		0.0	2.9	2.9	0.0	2.9	2.9
11	**Additional Capital Cost Allowance**		0.0	3.7	3.7	0.0	3.0	3.0
12	**Impact on Taxable Income** (line 10 - line 11)		0.0	(0.8)	(0.8)	0.0	(0.1)	(0.1)
13	**Income Tax Rate**	3	0.3	0.3	0.3	0.3	0.3	0.3
14	**Addition to Variance Account - Nuclear Waste Management Capital Expenditures Adjustment** (line 12 x line 13)		0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)
	Entry (iv): Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2013 for April 1, 2008 to December 31, 2008 and in 2014 for 2009 year	4						
15	**Actual SR&ED ITCs, net of Tax on ITCs, at 75%**	5	(0.1)	(8.5)	(8.6)	(0.1)	(12.7)	(12.8)
16	**Actual SR&ED ITCs, net of Tax on ITCs, at 100%** (line 15 x 4/3)		(0.1)	(11.3)	(11.4)	(0.2)	(16.9)	(17.0)
17	**Addition to Variance Account - SR&ED ITCs Recognition Percentage Increase for 2008 / 2009** (line 16 - line 15)		(0.0)	(2.8)	(2.9)	(0.0)	(4.2)	(4.3)
	Entry (v): ITC Rate Reduction from 20% to 15% Effective in 2014							
18	**Forecast SR&ED ITCs Based on 20% ITC Rate, at 75%**	6	0.0	0.0	0.0	0.1	13.1	13.2
19	**Forecast SR&ED ITCs Based on 15% ITC Rate, at 75%** (line 18 x 3/4)		0.0	0.0	0.0	0.1	9.8	9.9
20	**Addition to Variance Account - ITC Rate Reduction Effective in 2014** ((line 18 - line 19) x 10/12)		0.0	0.0	0.0	0.0	2.7	2.8
21	**Total Addition to Variance Account** (line 3 + line 9 + line 14 + line 17 + line 20)		(0.1)	(4.5)	(4.6)	(0.0)	(3.4)	(3.5)

Notes:
1 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132 , Attachment 1, Table 6.
2 Annualized forecasts for 2013 and 2014 have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008 using the methodology from the EB-2012-0002 Payment Amounts Order, and are calculated as shown in EB-2012-0002 Ex. H1-1-2 Table 6, Note 2.
3 2013 tax rate from EB-2013-0321 Ex. L-1.0-1 Staff-002, Attachment 1, Table 29, line 29. 2014 tax rate from EB-2013-0321 Payment Amounts Order, App. A, Table 7, line 31.
4 Entry (iv) was recorded in 2013 following the resolution during 2013 of the 2008 taxation year audit, and in 2014 following the resolution during 2014 of the 2009 taxation year audit. An additional entry of less than $0.1M/year is recorded in 2013 and 2014 relating to SR&ED qualifying capital expenditures.
5 Represents SR&ED ITCs, net of tax on ITCs , for the period from April 1, 2008 to December 31, 2008 and for full year 2009 previously credited to ratepayers at 75% through the December 31, 2010 and December 31, 2012 approved balances of the Income and Other Taxes Variance Account. The amount in col. (c) can be calculated as: 3/2 x (EB-2010-0008 Ex. H1-1-1, Table 13, col. (a), line 2 + line 4). The amount in col. (f) can be calculated as: 3/2 x (EB-2010-0008 Ex H1-1-1, Table 13 col. (b), line 2 + line 4).
6 The annualized forecast for 2014 is calculated from EB-2010-0008 Ex. F4-4-1 as follows: Table 2, line 5 col. (e) multiplied by 3/2 for previously regulated hydroelectric, and Table 3, line 6, col. (e) multiplied by 3/2 for nuclear.

Table 7
Capacity Refurbishment Variance Account - Hydroelectric
Summary of Account Transactions - 2014 ($M)

Line No.	Particulars	Note	Current Jan - Oct 2014	Projected Nov - Dec 2014	(a)+(b) Projected Total
			(a)	(b)	(c)
	Previously Regulated Hydroelectric:				
1	**Niagara Tunnel Net Plant Amount Not Reflected in EB-2010-0008 Rate Base**	1	1,345.8		
2	**Weighted Average Cost of Capital - EB-2010-0008**	2	7.40%		
3	**Niagara Tunnel Project - Cost of Capital** (line 1 x line 2 x 10/12)		83.0		83.0
4	**Niagara Tunnel Project - Depreciation**	3	12.2		12.2
5	**Difference Between Forecast and Actual / Projected Capital Cost Allowance Deduction**	4	(0.7)		(0.7)
6	**Increase in Regulatory Taxable Income**	5	61.8		61.8
7	**Niagara Tunnel Project - Income Tax Impact** (line 6 x 25 % / (1 - 25%))		20.6		20.6
8	**Niagara Tunnel Project - Total Capital Addition** (line 3 + line 4 + line 7)		115.8		115.8
	Capital Additions for Other Projects:				
9	**Sir Adam Beck I GS Unit G7 Frequency Conversion**		0.4	0.0	0.4
10	**Sir Adam Beck I GS Unit G3 Upgrade**		1.2	0.0	1.2
11	**Sir Adam Beck I GS Unit G10 Upgrade**		0.0	(0.1)	(0.1)
12	**Addition to Variance Account for Other Projects Before Adjustment** (lines 9 through 11)	6	1.6	(0.1)	1.5
13	**Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment**	7	N/A	(0.1)	(0.1)
14	**Addition to Variance Account for Other Projects** (line 12 - line 13)		1.6	0.0	1.6
15	**Total Addition to Variance Account - Previously Regulated Hydroelectric** (line 8 + line 14)		117.4	0.0	117.4

Notes:

1 Represents the 2014 Niagara Tunnel project net plant rate base value reflected in the EB-2013-0321 Board-approved revenue requirement. The value is calculated as follows: Board-approved in-service amount for the new Niagara Tunnel of $1,364.6M (EB-2013-0321 Payment Amounts Order, App. A, Table 1a, Note 2) less the resulting 2014 accumulated depreciation rate base amount of $18.8M.

2 From EB-2010-0008 Payment Amounts Order, App. A, Table 5b, col. (c), line 6.

3 Represents 10/12 of the 2014 annual depreciation expense of $14.4M, which can be calculated as: $14.7M (EB-2013-0321 Payment Amounts Order, Appendix A, Table 1a, Note 2) less $0.3M for pre-2013 in-service amount (EB-2013-0321 Ex. L-9.1-17 SEC-131, Chart 1, col. (a)).

4 Amount is calculated as the difference between forecast CCA deduction of $36.1M and actual/projected 2014 CCA deduction of $36.9M related to the Niagara Tunnel Project, multiplied by 10/12. The forecast amount is the average of 2011 and 2012 CCA amounts underpinning the OEB-approved forecast income tax expense in EB-2010-0008, and can be found in EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 7, Note 4, line 1a, col. (h).

5 The increase in regulatory taxable income is calculated as the sum of lines 4 and 5, plus the return on equity (“ROE”) component of the cost of capital addition at line 3. The 2014 ROE component is calculated as: net plant amount at line 1, multiplied by the EB-2010-0008 OEB-approved equity portion (47%) of the capital structure, multiplied by the OEB-approved ROE rate of 9.55% (from EB-2010-0008 Payment Amounts Order, App A, Table 5b, col. (b), line 5), multiplied by 10/12.

6 Additions to the account for January to October 2014 also include an entry of less than $0.1M related to the Sir Adam Beck G9 Upgrade project.

7 The adjustments are per the EB-2013-0321 Payment Amounts Order App. G., p. 10 requirements which are the same as those described in Ex. H1-1-1 Table 3, Note 4 and Ex. H1-1-1 Table 13, Note 6.

Table 8
Pension and OPEB Cost Variance Account
Summary of Account Transactions - 2013 and 2014[1] ($M)

Line No.	Particulars	Note	Actual 2013[2] Previously Regulated Hydroelectric	Actual 2013[2] Nuclear	Actual 2013[2] Total	Current Activity Jan to Oct 2014 Previously Regulated Hydroelectric	Current Activity Jan to Oct 2014 Nuclear	Current Activity Jan to Oct 2014 Total
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Forecast Accrual Pension Costs - EB-2012-0002**	3	7.0	138.4	145.4	5.8	115.3	121.1
2	**Forecast Accrual OPEB Costs - EB-2012-0002**	3	8.2	163.0	171.2	6.8	135.8	142.6
3	**Total Forecast Accrual Pension and OPEB Costs** (line 1 + line 2)		15.1	301.4	316.5	12.6	251.2	263.8
4	**Actual Accrual Pension Costs**	4	18.0	365.3	383.3	18.4	341.4	359.8
5	**Actual Accrual OPEB Costs**	4	11.5	233.7	245.2	8.0	149.4	157.4
6	**Total Actual Accrual Pension and OPEB Costs** (line 4 + line 5)		29.5	599.0	628.5	26.4	490.8	517.2
7	**Addition to Variance Account - Pension Costs** (line 4 - line 1)		11.0	226.9	237.9	12.6	226.1	238.6
8	**Addition to Variance Account - OPEB Costs** (line 5 - line 2)		3.4	70.7	74.0	1.2	13.5	14.8
9	**Addition to Variance Account - Income Tax Impact**	5	4.3	86.1	90.4	3.0	55.3	58.3
10	**Total Addition to Variance Account** (line 7 + line 8 + line 9)		18.6	383.7	402.3	16.8	294.9	311.7

Notes:
1 All cost amounts are presented on a CGAAP basis, as per the EB-2012-0002 Payment Amounts Order, App. B.
2 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 8.
3 Forecasts have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008, and are the same as those used to derive the OEB-approved 2012 additions to the variance account (shown in EB-2012-0002 Ex. H1-1-2, Table 5, line 1 (pension) and line 2 (OPEB), cols (d)-(f)). Total forecast costs for the regulated operations are as per EB-2012-0002 Payment Amounts Order, App. B, p. 6, determined as $26.38M/month x 12 for 2013 and $26.38/month x 10 for January to October 2014.
4 Amounts represent the regulated portion (excluding newly regulated hydroelectric) of OPG's 2013 and January to October 2014 total actual pension and OPEB costs on a CGAAP basis.
5 From Ex. H1-1-1 Table 8a, line 8.

Numbers may not add due to rounding.

Table 8a
Pension and OPEB Cost Variance Account
Calculation of Income Tax Impact - 2013 and 2014 ($M)

Line No.	Particulars	Note	Actual 2013[1]			Current January 1 to October 31, 2014		
			Previously Regulated Hydroelectric	Nuclear	Total	Previously Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Forecast Regulatory Income Tax Impact**	2	0.5	10.3	10.8	0.4	8.6	9.0
	Actual Additions to / Deductions from Regulatory Earnings Before Tax							
2	**Accrual Pension Costs**	3	18.0	365.3	383.3	18.4	341.4	359.8
3	**Accrual OPEB Costs**	4	11.5	233.7	245.2	8.0	149.4	157.4
4	**Less: Pension Plan Contributions**	5	11.4	231.6	242.9	12.5	233.1	245.7
5	**Less: OPEB Payments**	5	3.8	78.1	81.9	3.6	66.0	69.6
6	**Net Additions to Regulatory Earnings Before Tax**		14.2	289.4	303.6	10.3	191.6	201.9
7	**Actual Regulatory Income Tax Impact** (line 6 x 25% / (1 - 25%))		4.7	96.5	101.2	3.4	63.9	67.3
8	**Addition to Variance Account - Regulatory Income Tax Impact** (line 7 - line 1)		4.3	86.1	90.4	3.0	55.3	58.3

Notes:
1 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 8a.
2 Forecasts have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008, and for 2013, are the same amounts used to derive the OEB-approved 2012 additions (shown in EB-2012-0002 Ex. H1-1-2, Table 5a, line 1, cols. (d)-(f)). For January to October 2014, the EB-2012-0002 annual forecasts are pro-rated by 10/12.
3 From Ex. H1-1-1 Table 8, line 4.
4 From Ex. H1-1-1 Table 8, line 5.
5 Represents the regulated portion (excluding newly regulated hydroelectric) of OPG's 2013 and January to October 2014 total actual pension and OPEB cash amounts. 2013 amounts in col. (c) are as shown in EB-2013-0321 Ex. L-1.0-1 Staff-002, Attachment 1, Table 29, lines 15 and 16. 2013 amounts at line 4 are also found in EB-2013-0321 Ex. L-6.8-1 Staff-114.

Numbers may not add due to rounding.

Table 9
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - 2013 and 2014

Line No.	Particulars	Note	Actual 2013[1]	Current Jan - Oct 2014	Projected Nov - Dec	(b)+(c) Projected 2014
			(a)	(b)	(c)	(d)
1	**Hydroelectric Rider 2013-A / 2014-A ($/MWh)**	2	3.04	2.02	2.02	
2	**Hydroelectric Rider 2013-B ($/MWh)**	3	0.58			
3	**Mar 2013 - Dec 2014 Hydroelectric Production Forecast Used to Set Rider 2013-A and Rider 2014-A (TWh)**	4	16.7	16.5	3.3	19.9
4	**Mar 2013 - Dec 2014 Actual / Projected Hydroelectric Production (TWh)**		15.9	16.2	3.5	19.7
5	**Actual / Projected Production Variance for Mar 2013 - Dec 2014 (TWh)** (line 3 - line 4)		0.8	0.3	(0.2)	0.1
6	**Addition to Variance Account ($M)** (line 5 x (line 1 + line 2))		2.9	0.6	(0.4)	0.2

Notes:

1 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 9, col. (a).
2 From EB-2012-0002 Payment Amounts Order, App. A, Table 1, line 13, col. (g) for 2013 and col. (h) for 2014.
3 Interim period shortfall rider in effect for 2013 from EB-2012-0002 Payment Amounts Order, App. A, Table 3, col. (a), line 7.
4 Value for 2013 is calculated from the EB-2012-0002 Payment Amounts Order, App. A, Table 3, col. (a): line 6 minus line 5.
Annual value for 2014 is from EB-2012-0002 Payment Amounts Order, App. A, Table 1, col. (g), line 12. Values for January to October 2014 and November to December 2014 are averages of the corresponding monthly forecasts found at EB-2012-0002 Ex. L-2-1 Staff-16, Attachment 1, Table 2, lines 1 and 3.

Table 10
Nuclear Liability Deferral Account
Summary of Account Transactions - 2013 and 2014 ($M)

Line No.	Particulars	Note	Actual 2013[1]	Current Jan - Oct 2014
			(a)	(b)
	Revenue Requirement Impact of Current Approved ONFA Reference Plan Effective January 1, 2012:			
1	**Depreciation Expense** (col. (a) from Table to Note 2, line 13a, col. (d); col. (b) = col. (a) x 10/12)	2	51.7	43.1
	Return on Rate Base			
2	**Average Asset Retirement Costs**	3	38.3	(13.4)
3	**Weighted Average Accretion Rate**	4	5.37%	5.37%
4	**Return on Rate Base** (col. (a) = line 2 x line 3; col. (b) = line 2 x line 3 x 10/12)		2.1	(0.6)
	Variable Expenses	5		
5	**Used Fuel Storage and Disposal Variable Expenses**		26.1	23.8
6	**Low & Intermediate Level Waste Management Variable Expenses**		1.0	1.0
7	**Total Variable Expenses** (line 5 + line 6)		27.1	24.8
	Income Tax Impact			
8	**Forecast Contributions to Nuclear Segregated Funds**	6	142.7	118.9
9	**Contributions to Nuclear Segregated Funds based on the Current Approved ONFA Reference Plan**	7	98.1	141.6
10	**Decrease (Increase) in Contributions to Nuclear Segregated Funds** (line 8 - line 9)		44.6	(22.7)
11	**Net Increase in Regulatory Taxable Income** (line 1 + line 4 + line 7 + line 10)		125.5	44.6
12	**Income Tax Rate**		25.00%	25.00%
13	**Income Tax Impact** (line 11 x line 12 / (1 - line 12))		41.8	14.9
14	**Addition to Deferral Account** (line 1 + line 4 + line 7 + line 13)		122.7	82.2

Notes:

1 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 10, col. (a).

2 The depreciation expense component of the addition to the deferral account is calculated as follows:

Table to Note 2 - Depreciation Expense ($M)

Line No.		Pickering Units 1 & 4 (formerly Pickering A)	Pickering Units 5-8 (formerly Pickering B)	Darlington	Total
		(a)	(b)	(c)	(d)
	Incremental ARC - Depreciation Impact of Adjustments at December 31, 2011 and 2012:				
1a	Asset Retirement Cost ("ARC") Adjustment at December 31, 2011 #	368.4	175.9	(105.1)	439.2
2a	Remaining Useful Life as at December 31, 2011(months) +	120.0	33.0	480.0	
3a	2012 Annual Depreciation (line 1a / line 2a x 12 for cols. (a) through (c))	36.8	64.0	(2.6)	98.2
4a	ARC Adjustment at December 31, 2012 ##	(178.5)	133.3	(231.7)	(276.9)
5a	Net ARC Adjustment Balance at December 31, 2012 (line 1a - line 3a + line 4a)	153.1	245.2	(334.2)	64.1
6a	Remaining Useful Life as at December 31, 2012 (months) ++	96.0	88.0	468.0	
7a	Annual Depreciation Beginning in 2013 (line 5a / line 6a x 12 for cols. (a) through (c))	19.1	33.4	(8.6)	44.0
	Base ARC (Excluding Incremental ARC Above) -- Depreciation Impact of Pickering Service Life Changes:				
8a	ARC at December 31, 2011 Excluding December 31, 2011 Adjustment *	17.3	(27.0)	1,485.0	1,475.4
9a	2012 Annual Depreciation (line 8a / line 2a x 12 for cols. (a) through (c))	1.7	(9.8)	37.1	29.0
10a	ARC at December 31, 2012 Excluding Dec. 31, 2011 and 2012 Adjustments (line 8a - line 9a)	15.6	(17.2)	1,447.9	1,446.3
11a	2013 Annual Depreciation (line 10a / line 6a x 12 for cols. (a) through (c))	1.9	(2.3)	37.1	36.7
12a	Annual Depreciation Impact Beginning in 2013 (line 11a - line 9a)	0.2	7.5	0.0	7.7
13a	Total Annual Depreciation Expense Impact Beginng in 2013 (line 7a + line 12a)	19.4	40.9	(8.6)	51.7

\# From EB-2013-0321, Ex. C2-1-1 Table 4, line 7 and EB-2012-0002 Ex. H1-1-2, Table 9, note 2, line 1a.

\+ Represents remaining estimated average service life, for accounting purposes, of the nuclear stations as at December 31, 2011, as per EB-2012-0002, Ex. H1-1-2, Table 9, Note 2, line 2a.

\## From EB-2013-0321 Ex. C2-1-1, Table 4, line 14.

\++ Represents remaining estimated average service life, for accounting purposes, of the nuclear stations as at December 31, 2012, as per EB-2013-0321 Ex. F4-1-1, page 3.

* Amount in col. (d) from EB-2013-0321 Ex. C2-1-1, Table 2, col. (b), line 28.

3 2013 value is calculated as follows from Note 2, col. (d): (line 5a + (line 5a - line 13a))/2. 2014 value is calculated as 2013 value less Note 2, line 13a, col. (d).

4 Per EB-2012-0002 Payment Amounts Order, App. B, p. 9.

5 Annual values calculated as the difference between: (A) the product of (i) 2013/2014 unit cost rates for each of the Used Fuel Storage and Disposal Programs and the Low and Intermediate Level Waste ("L&ILW") Storage and Disposal Programs arising from the current approved ONFA Reference Plan, and (ii) average number of forecast fuel bundles and L&ILW volumes reflected in the EB-2010-0008 payment amounts, and (B) the average of 2011 and 2012 forecast variable expenses reflected in the EB-2010-0008 payment amounts. For January to October 2014, the annual forecast value is pro-rated by 10/12.

6 Annual values calculated as the average of 2011 and 2012 contributions from EB-2010-0008 Payment Amounts Order, App. A: Table 6, line 16, col. (c) for 2011 and Table 7, line 16, col. (c) for 2012. For January to October 2014, the annual forecast value is pro-rated by 10/12.

7 2013 value is as shown in EB-2013-0321 Ex. L-1.0-1 Staff-002, Attachment 1, Table 7, col. (a), line 16.

Numbers may not add due to rounding.

Table 11
Nuclear Development Variance Account
Summary of Account Transactions - 2014[1] ($M)

Line No.	Particulars	Current Jan - Oct 2014	Projected Nov - Dec 2014	(a)+(b) Projected Total 2014
		(a)	(b)	(c)
1	**Forecast Costs - EB-2010-0008 / EB-2012-0002 / EB-2013-0321**	0.0	0.0	0.0
2	**Actual Costs**	1.2	0.4	1.6
3	**Addition to Variance Account** (line 2 - line 1)	1.2	0.4	1.6

Notes:
1 The 2013 forecast is nil as per EB-2012-0002 Payment Amounts Order, App. B, p. 9, as no Darlington New Nuclear costs were reflected in the EB-2010-0008 approved revenue requirement. Similarly, the 2014 forecast is nil as per the EB-2013-0321 Payment Amounts Order, App. G, p. 9, as no such costs were reflected in the EB-2013-0321 approved revenue requirement.

Table 12
Capacity Refurbishment Variance Account - Nuclear
Summary of Account Transactions - 2013 and 2014 ($M)

Line No.	Particulars	Note	Actual 2013[1]	Current Jan-Oct 2014	Projected Nov-Dec 2014	(b)+(c) Projected Total 2014
			(a)	(b)	(c)	(d)
	Non-Capital Addition to Variance Account:					
	Forecast Non-Capital Costs - EB-2012-0002 / EB-2013-0321:					
1	**Darlington Refurbishment**	2,3	5.2	4.3	2.1	6.4
2	**Fuel Channel Life Cycle Management Project**	2,3	5.9	4.9	0.6	5.5
3	**Pickering Continued Operations**	2,3	42.0	35.0	3.1	38.1
4	**Fuel Channel Life Extension Project**	2,3	0.0	0.0	0.0	0.0
5	**Total**		53.1	44.2	5.8	50.0
	Actual / Projected Non-Capital Costs:					
6	**Darlington Refurbishment**		6.3	5.6	3.5	9.1
7	**Fuel Channel Life Cycle Management Project**		9.2	7.8	1.0	8.8
8	**Pickering Continued Operations**		41.5	25.4	6.6	32.0
9	**Fuel Channel Life Extension Project**		0.0	3.0	2.2	5.2
10	**Total**		57.0	41.8	13.2	55.1
	Non-Capital Addition to Variance Account:					
11	**Darlington Refurbishment - Non-Capital Costs** (line 6 - line 1)		1.1	1.3	1.4	2.7
12	**Fuel Channel Life Cycle Management Project - Non-Capital Costs** (line 7 - line 2)		3.3	2.9	0.4	3.3
13	**Pickering Continued Operations - Non-Capital Costs** (line 8 - line 3)		(0.5)	(9.6)	3.5	(6.1)
14	**Fuel Channel Life Extension Project** (line 9 - line 4)		0.0	3.0	2.2	5.2
15	**Non-Capital Addition to Variance Account Before Adjustment** (lines 11 through 14)		4.0	(2.4)	7.5	5.1
16	**Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment**	4	N/A	N/A	2.7	2.7
17	**Total Non-Capital Addition to Variance Account - Nuclear** (line 15 - line 16)		4.0	(2.4)	4.8	2.4
	Capital Addition to Variance Account - Darlington Refurbishment:					
18	**Forecast Cost of Capital Amount** (col. (c): from Note 5, line 3b, col. (c) x 2/12)	5		0.0	1.8	1.8
19	**Projected 2014 Net Plant Rate Base Amount**	6		126.3	126.3	
20	**Weighted Average Cost of Capital**	7		7.40%	6.86%	
21	**Projected Cost of Capital Amount** (col. (b): line 19 x line 20 x 10/12; col. (c): line 19 x line 20 x 2/12)			7.8	1.4	9.2
22	**Cost of Capital Variance** (line 21 - line 18)			7.8	(0.4)	7.4
23	**Forecast Depreciation** (col. (c): from Note 5, line 5b, col. (c) x 2/12)	5		0.0	0.8	0.8
24	**Actual / Projected Depreciation**			3.7	0.7	4.4
25	**Depreciation Variance** (line 24 - line 23)			3.7	(0.0)	3.7
	Income Tax Impact:					
26	**Forecast Capital Cost Allowance Deduction**	8		3.3	11.1	14.4
27	**Projected Capital Cost Allowance Deduction**			27.3	5.5	32.8
28	**Difference** (line 26 - line 27)			(24.0)	5.7	(18.3)
29	**Net Increase (Decrease) in Regulatory Taxable Income**	9,10		(15.6)	6.5	(9.1)
30	**Income Tax Rate**	11		25.00%	25.00%	25.00%
31	**Income Tax Impact** (line 29 x line 30 / (1 - line 30))			(5.2)	2.2	(3.0)
32	**Capital Addition to Variance Account Before Adjustment** (line 22 + line 25 + line 31)			6.3	1.8	8.0
33	**Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment**			N/A	0.8	0.8
34	**Total Capital Addition to Variance Account - Nuclear** (line 32 - line 33)		4.3	6.3	0.9	7.2

For notes see Table 12a.

Table 12a
Notes to Table 12
Capacity Refurbishment Capital Costs - 2013 and 2014 ($M)

Notes:

1 Non-capital variance account addition calculation is as shown in EB-2013-0321 Ex. L-9.1-17 SEC-132, Table 12.

2 Forecasts for 2013 and January to October 2014 have been determined based on amounts reflected in the EB-2010-0008 payment amounts, with individual annual values found at EB-2012-0002 Ex. H1-1-2, Table 12, col. (d), lines 2-4. The total annual non-capital cost forecast of $53.1M is as per the EB-2012-0002 Payment Amounts Order, App. B, p. 10, at $4.42/month. The total January to October 2014 non-capital cost forecast is therefore $4.42/month multiplied by 10 months.

3 In accordance with the EB-2013-0321 Payment Amounts Order (App. G, p.10), the forecasts for November and December 2014 have been determined as shown below at line 4a, on the basis of amounts underpinning the EB-2013-0321 payment amounts:

Table to Note 3 - EB-2013-0321 and OPG's 2014-2016 Business Plan Forecast Costs ($M)

Line No.		Darlington Refurbishment Non-Capital[#]	Fuel Channel Life Cycle Mgmt Project[##]	Pickering Continued Operations[+]	Fuel Channel Life Extension Project[++]
		(a)	(b)	(c)	(d)
1a	2014 Full Year Forecast Costs - EB-2013-0321	6.6	6.8	37.1	0.0
2a	2015 Full Year Forecast Costs - EB-2013-0321	18.2	0.6	0.0	0.0
3a	Total Forecast Costs - EB-2013-0321	24.9	7.4	37.1	0.0
4a	Nov - Dec 2014 Average Annual Forecast from EB-2013-0321 ((line 3a / 24 months) x 2)	2.1	0.6	3.1	0.0
5a	2014 Full Year Forecast Costs - OPG's 2014-2016 Business Plan	6.6	8.8	39.1	
6a	2015 Full Year Forecast Costs - OPG's 2014-2016 Business Plan	20.4	0.5	0.0	
7a	Total Forecast from OPG's - 2014-2016 Business Plan	27.0	9.2	39.1	
8a	Nov to Dec 2014 Average Annual Forecast - OPG's 2014-2016 Business Plan ((line 7a / 24 months) x 2)	2.3	0.8	3.3	
9a	Nov to Dec 2014 EB-2013-0321 Impact Statement (Ex. N1) Adjustment (cols. (a)-(c): line 8a - line 4a)	0.2	0.2	0.2	2.2

\# Lines 1 and 2a from EB-2013-0321 Decision with Reasons, p. 55.
\## Lines 1a and 2a from EB-2013-0321 Ex. F2-3-1, Table 1, line 11, cols. (e) and (f).
\+ Lines 1a and 2a from EB-2013-0321 Ex. F2-2-3, p. 4, Chart 1, "Subtotal" line.
\++ The Fuel Channel Life Extension Project was not reflected in OPG's 2013-2015 Business Plan underpinning the EB-2013-0321 payment amounts.

4 The adjustments are per the EB-2013-0321 Payment Amounts Order (App. G, p.10) requirement that amounts recorded in the account do not include those that OPG indicated it is not seeking to recover from, or refund to, ratepayers as part of the differences between the revenue requirement in its EB-2013-0321 pre-filed evidence and the information based on OPG's 2014-2016 Business Plan, which was provided in the EB-2013-0321 Impact Statement at Ex. N1. The adjustments are 2/24 of the higher corresponding costs reflected in the total test period OM&A increase of $26M (EB-2013-0321 Ex. N1-1-1, Chart 1) between OPG's EB-2013-0321 pre-filed evidence and its 2014-2016 Business Plan. This difference was not included in the updated revenue requirement in the Ex. N1 impact statement. The individual November to December 2014 adjustments total $2.7M and are shown in Note 3, line 9a.
The Fuel Channel Life Cycle Extension Project was considered in OPG's 2014-2016 Business Plan (see EB-2013-0321 Ex. F2-3-3, Attachment 1, Tab 11) as part of the nuclear portfolio project OM&A. In addition to addressing requirements with respect to the EB-2013-0321 Ex. N1 Impact Statement, the adjustment also limits the amount recoverable from ratepayers for project cost variances to the variance in total nuclear portfolio project OM&A from OPG's 2014-2016 Busines Plan.

5 The annual forecast (reference) amounts are determined as follows:

Table to Note 5 - Darlington Refurbishment Forecast Capital Amounts - EB-2013-0321 ($M)

Line No.		2014	2015	((a)+(b)) / 2 Reference Amount
		(a)	(b)	(c)
1b	Forecast Net Plant Rate Base Amount[a]	116.0	204.6	
2b	Weighted Average Cost of Capital[b]	6.86%	6.85%	
3b	Cost of Capital Forecast Amount (line 1b x line 2b)	8.0	14.0	11.0
4b	ROE Component of Cost of Capital Amount[c]	4.9	8.6	6.7
5b	Depreciation[d]	3.0	6.1	4.5
6b	Capital Cost Allowance Deduction[e]	39.3	94.3	66.8

a From EB-2013-0321 Ex. L-4.9-1 Staff-048, p. 2, Chart 1.
b From EB-2013-0321 Payment Amounts Order, App. A, Tables 5b and 6b, col. (c), line 6.
c Calculated as line 1b x equity portion (45%) of the EB-2013-0321 capital structure x EB-2013-0321 ROE rate of 9.36% (2014) and 9.30% (2015) (from EB-2013-0321 Payment Amounts Order, App A, Tables 6b and 7b, col. (b), line 5).
d From EB-2013-0321 Ex. F4-1-1, Table 2, Note 2 and EB-2013-0321 Ex. L-4.9 Staff-048, p. 2, Chart 1.
e From EB-2013-0321 Ex. D2-2-1, p. 29, Note 2.

6 The 2014 projected net plant rate base amount is calculated as follows:

Table to Note 6 - 2014 Projected Darlington Refurbishment Net Plant Rate Base Amount ($M)

Line No.		Opening Balance^	In-Service Additions/ Depreciation	(a)-(b) Closing Balance	((a)+(c)) / 2 Rate Base Amount
		(a)	(b)	(c)	(d)
1b	Gross Plant	104.2	53.4	157.5	130.8
2b	Less: Accumulated Depreciation	2.3	4.4	6.7	4.5
3b	Net Plant	101.9	49.0	150.8	126.3

^ Amounts are 2013 closing values from EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 12a, Note 1, col. (c).

7 Col. (b) is from EB-2010-0008 Payment Amounts Order, App. A, Table 5b, col. (c), line 6. Col. (c) is from EB-2013-0321 Payment Amounts Order, App. A, Table 6b, col. (c), line 6.

8 Col. (b) is 10/12 x the average of cols. (b) and (c) from EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 12a, line 5. Col. (c) is from Note 5, col. (c), line 6b x 2/12.

9 The decrease in regulatory taxable income in col. (b) is calculated as the sum of lines lines 22 and 28, plus the ROE component of the cost of capital variance at line 22. The ROE component is calculated as: net plant amount at line 19, multiplied by the EB-2010-0008 OEB-approved equity portion (47%) of the capital structure, multiplied by the OEB-approved ROE rate of 9.55% (from EB-2010-0008 Payment Amounts Order, App A, Table 5b, col. (b), line 5), multiplied by 10/12.

10 The increase in regulatory taxable income in col. (c) is calculated as the sum of lines 22 and 28, plus the ROE component of the cost of capital variance at line 22. The ROE component of the variance is calculated as 2/12 of the difference between: (i) line 19 multiplied by the EB-2013-0321 OEB-approved equity portion (45%) of the capital structure, multiplied by the OEB-approved ROE rate of 9.36% (from Note c), and (ii) Note 5, col. (c), line 4b.

11 From EB-2013-0321 Payment Amounts Order, App. A, Table 7, line 31.

Table 13
Bruce Lease Net Revenues Variance Account
Summary of Account Transactions - 2013 and 2014

Line No.	Particulars	Note	Actual 2013[1]	Current Jan - Oct 2014	Projected Nov - Dec 2014	(b)+(c) Projected Total 2014
			(a)	(b)	(c)	(d)
1	**Actual / Projected Total Bruce Lease Net Revenues ($M)**	2	7.9	122.2	3.8	126.0
2	**Forecast Bruce Lease Net Revenues - EB-2010-0008 / EB-2013-0321 ($M)**	3	135.5	135.5	40.2	
3	**Forecast Nuclear Production (TWh)**	4	51.0	51.0	47.8	
4	**Rate Credited to Customers ($/MWh)** (line 2 / line 3)		2.7	2.7	0.8	
5	**Actual / Projected Nuclear Production (TWh)**	5	44.7	39.8	8.1	
6	**Amount Credited to Customers ($M)** (line 4 x line 5)		118.5	105.8	6.8	112.6
7	**Total Addition to Variance Account Before Adjustment ($M)** (line 6 - line 1)		110.5	(16.4)	3.0	(13.4)
8	**Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment ($M)**	6	N/A	N/A	3.3	3.3
9	**Total Addition to Variance Account ($M)** (line 7 - line 8)		110.5	(16.4)	(0.3)	(16.7)
10	**Less: Addition to Derivative Sub-Account ($M)**	7	24.6	(57.5)	0.0	(57.5)
11	**Addition to Non-Derivative Sub-Account ($M)** (line 9 - line 10)		85.9	41.1	(0.3)	40.8

Notes:

1 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132 (corrected version filed on June 4, 2014), Attachment 1, Table 13, col. (a)

2 From Ex. H1-1-1 Table 13a, line 30.

3 Per EB-2012-0002 Payment Amounts Order, App. B, p. 11-12, amount in cols. (a) and (b) is determined as the annual average (at $11.30M/month) of Bruce Lease net revenues reflected in the EB-2010-0008 approved revenue requirement (EB-2010-0008 Payment Amounts Order, App. A, Table 2, line 20). Per EB-2013-0321 Payment Amounts Order, App. G, pp. 11-12, amount in col. (c) is determined as the average (at $3.35M/month) of the 2014 and 2015 of Board-approved Bruce Lease net revenues (EB-2013-0321 Payment Amounts Order, App. A, Table 3, line 20).

4 Value in col. (a) and (b) is the average of 2011 and 2012 annual nuclear production from EB-2010-0008 Payment Amounts Order, App. A, Table 3, line 1. Value in col. (c) is the average of 2014 and 2015 annual nuclear production from EB-2013-0321 Payment Amounts Order, App. A, Table 4, line 1, cols. (g) and (h).

5 Col. (a) is from EB-2013-0321 Ex. L-1.0-1 Staff-002, Attachment 1, Table 14, col. (d), line 3. Cols. (b) and (c) are from Ex. H1-1-1, Table 14, line 10, cols. (b) and (c), respectively.

6 The adjustment in col. (c) is per the EB-2013-0321 Payment Amounts Order (App. G, p. 11) requirement that OPG shall ensure that amounts recorded in the account do not include those that OPG indicated it is not seeking to recover from, or refund to, ratepayers as part of the differences between the revenue requirement in its EB-2013-0321 pre-filed evidence and the information based on OPG’s 2014-2016 Business Plan provided in the EB-2013-0321 Impact Statement at Ex. N1. The adjustments represent a 2/12 of the $20M total test period decrease (EB-2013-0321 Ex. N1-1-1, Chart 1) in forecast Bruce Lease net revenues between OPG's EB-2013-0321 pre-filed evidence and the 2014-2016 Business Plan that was not included in the updated revenue requirement in that impact statement.

7 From Ex. H1-1-1 Table 13a, line 29.

Numbers may not add due to rounding.

Table 13a
Bruce Lease Net Revenue Variance Account
Comparison of Bruce Lease Net Revenues - 2013 and 2014 ($M)[1]

Line No.	Particulars	Actual 2013[2]	Average of 2011/2012 Board Approved (EB-2010-0008)	(b) - (a) Change	Current Jan - Oct 2014	10/12 of Average of 2011/2012 Board Approved (EB-2010-0008)	(e) - (d) Change	Projected Nov - Dec 2014	2/12 of Average 2014/2015 Board Approved (EB-2013-0321)	(h) - (g) Change	(d) + (g) Projected Total 2014	Board Approved 2014 (EB-2013-	(k) - (j) Change
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Revenues:												
1	**Site Services (OPG to Bruce Power)**	0.6	0.6	(0.1)	0.5	0.5	(0.1)	0.1	0.1	0.0	0.7	0.7	0.0
2	**Low & Intermediate Level Waste Services**	5.3	13.0	7.6	3.2	10.8	7.6	2.4	2.7	0.2	5.6	14.8	9.2
3	**Cobalt-60**	0.6	0.5	(0.1)	0.4	0.4	(0.0)	0.1	0.1	0.0	0.5	0.5	0.0
4	**Total Services Revenue**	6.6	14.0	7.4	4.2	11.7	7.5	2.6	2.9	0.2	6.8	16.0	9.2
5	**Fixed (Base) Rent**	40.9	40.9	0.0	34.1	34.1	0.0	4.6	6.4	1.9	38.7	38.7	(0.0)
6	**Supplemental Rent - Non-Derivative Portion**	203.8	194.5	(9.3)	172.7	162.1	(10.6)	34.9	35.0	0.1	207.5	207.9	0.4
7	**Amortization of Initial Deferred Rent**	12.1	12.1	(0.1)	10.1	10.1	(0.0)	2.0	2.0	0.0	12.1	12.1	0.0
8	**Total Non-Derivative Rent Revenue**	256.9	247.5	(9.4)	216.8	206.3	(10.6)	41.4	43.5	2.0	258.3	258.6	0.4
9	**Total Non-Derivative Revenue** (line 4 + line 8)	263.5	261.6	(1.9)	221.0	218.0	(3.0)	44.1	46.3	2.3	265.1	274.6	9.6
10	**Supplemental Rent - Derivative Portion**	(32.8)	0.0	32.8	76.7	0.0	(76.7)	0.0	0.0	0.0	76.7	0.0	(76.7)
11	**Total Revenue** (line 9 + line 10)	230.7	261.6	30.9	297.7	218.0	(79.7)	44.1	46.3	2.3	341.8	274.6	(67.1)
	Costs:												
12	**Depreciation**	104.5	34.5	(70.0)	86.6	28.8	(57.9)	17.8	17.8	0.0	104.4	106.8	2.3
13	**Property Tax**	11.6	13.8	2.3	9.8	11.5	1.7	1.9	2.3	0.4	11.7	13.7	2.0
14	**Accretion**	369.0	300.9	(68.1)	322.4	250.7	(71.7)	64.5	65.0	0.5	386.9	382.9	(4.0)
15	**(Earnings) Losses on Segregated Funds**	(337.1)	(295.4)	41.7	(346.8)	(246.2)	100.6	(57.7)	(58.9)	(1.2)	(404.5)	(347.0)	57.4
16	**Used Fuel Storage and Disposal**	54.0	20.5	(33.5)	47.8	17.1	(30.7)	10.3	9.2	(1.0)	58.0	54.3	(3.7)
17	**Waste Management Variable Expenses and Facilities Removal Costs**	2.8	0.8	(2.0)	3.6	0.6	(3.0)	0.2	0.5	0.3	3.9	2.4	(1.5)
18	**Interest**	20.2	9.4	(10.8)	15.3	7.8	(7.5)	2.8	2.2	(0.6)	18.1	13.4	(4.7)
19	**Total Costs Before Income Tax**	225.0	84.5	(140.5)	138.7	70.4	(68.3)	39.8	38.2	(1.6)	178.5	226.5	48.0
20	**Income Tax - Current - Non-Derivative Portion**	26.9	4.3	(22.6)	49.9	3.6	(46.3)	11.6	9.7	(1.9)	61.5	57.1	(4.4)
21	**Income Tax - Future/Deferred - Non-Derivative Portion**	(20.8)	37.3	58.1	(32.2)	31.1	63.3	(11.1)	(8.2)	2.9	(43.4)	(48.6)	(5.2)
22	**Total Income Tax - Non-Derivative Portion**	6.1	41.6	35.5	17.6	34.7	17.0	0.5	1.4	1.0	18.1	8.5	(9.6)
23	**Total Non-Derivative Costs** (line 19 + line 22)	231.1	126.0	(105.0)	156.3	105.0	(51.3)	40.3	39.6	(0.6)	196.6	235.0	38.4
24	**Income Tax - Current - Derivative Portion**	(26.9)	0.0	26.9	(0.6)	0.0	0.6	0.0	(3.3)	(3.3)	(0.6)	(19.8)	(19.2)
25	**Income Tax - Future/Deferred - Derivative Portion**	18.7	0.0	(18.7)	19.7	0.0	(19.7)	0.0	3.3	3.3	19.7	19.8	0.1
26	**Total Income Tax - Derivative Portion**	(8.2)	0.0	8.2	19.2	0.0	(19.2)	0.0	0.0	0.0	19.2	0.0	(19.2)
27	**Total Costs** (line 23 + line 26)	222.8	126.0	(96.8)	175.5	105.0	(70.5)	40.3	39.6	(0.6)	215.8	235.0	19.2
28	**Bruce Lease Net Revenues - Non-Derivative Portion** (line 9 - line 23)	32.5	135.5	103.1	64.7	113.0	48.3	3.8	6.7	2.9	68.5	39.7	(28.8)
29	**Bruce Lease Net Revenues - Derivative Portion** (line 10 - line 26)	(24.6)	0.0	24.6	57.5	0.0	(57.5)	0.0	0.0	0.0	57.5	0.0	(57.5)
30	**Total Bruce Lease Net Revenues** (line 28 + line 29)	7.9	135.5	127.6	122.2	113.0	(9.3)	3.8	6.7	2.9	126.0	39.7	(86.3)

Notes:

1. All amounts for 2013 and January to October 2014 are presented on a CGAAP basis, as this is the basis used to determine EB-2010-0008 Board-approved forecasts for 2011 and 2012. All amounts for November to December 2014 are presented on a US GAAP basis, which was used to determine the EB-2013-0321 Board approved forecast (shown in col. (k) for 2014).
2. With the exception of lines 5 and 21 (which have been adjusted to CGAAP basis for a net increase to total Bruce Lease Net Revenues at line 30 of $1.6M, per EB-2013-0321 Ex. L-9.1-17 SEC-132 (corrected version filed on June 4, 2014), Attachment 1, Table 13, note 2) and internally calculated values at lines 8, 11, 22, 27, 28 and 30, amounts are as shown in EB-2013-0321, Ex. L-1.0-1 Staff-002, Attachment 1, Table 36.
3. Cols. (a), (d) and (g) from corresponding columns of Ex. H1-1-1 Table 13b, line 38.
4. Cols. (a), (d) and (g) from corresponding columns of Ex. H1-1-1 Table 13b, line 46.
5. Cols. (a), (d) and (g) from corresponding columns of Ex. H1-1-1 Table 13b, line 37.
6. Cols. (a), (d) and (g) from corresponding columns of Ex. H1-1-1 Table 13b, line 45.

Table 13b
Bruce Lease Net Revenues Variance Account
Calculation of Bruce Income Taxes - 2013 and 2014 ($M)[1]

Line No.	Particulars	Note	Actual 2013[2]	Current Jan - Oct 2014	Projected Nov - Dec 2014	(b)+(c) Projected Total 2014
			(a)	(b)	(c)	(d)
	Determination of Taxable Income					
1	**Earnings (Loss) Before Tax**	3	5.7	159.0	4.3	163.3
	Additions for Tax Purposes - Temporary Differences:					
2	**Base Rent Accrual**		40.1	35.0	7.4	42.4
3	**Depreciation**		104.5	86.6	17.8	104.4
4	**Accretion**		369.0	322.4	64.5	386.9
5	**Used Fuel and Waste Management Expenses and Faciities Removal Costs**		56.8	51.4	10.5	61.9
6	**Receipts from Nuclear Segregated Funds**		30.4	29.3	19.7	48.9
7	**Change in Fair Value of Bruce Derivative**		32.8	(76.7)	0.0	(76.7)
8	**Other**		2.5	4.4	0.9	5.2
9	**Total Additions - Temporary Differences**		636.2	452.4	120.7	573.1
	Deductions for Tax Purposes - Permanent Differences:					
10	**Deferred Rent Revenue**		14.2	11.8	2.4	14.2
	Deductions for Tax Purposes - Temporary Differences:					
11	**CCA**		5.7	4.4	0.9	5.3
12	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning and Facilities Removal**		91.3	75.2	22.7	97.9
13	**Contributions to Nuclear Segregated Funds**		85.9	(26.2)	(5.1)	(31.3)
14	**Earnings (Losses) on Nuclear Segregated Funds**		337.1	346.8	57.7	404.5
15	**Supplemental Rent Payment Reduction**		78.7	0.0	0.0	0.0
16	**Total Deductions - Temporary Differences**		598.6	400.2	76.2	476.4
17	**Taxable Income/(Loss) Before Loss Carry-Over** (line 1 + line 9 - line 10- line 16)		29.1	199.4	46.5	245.9
18	**Tax Loss Carry-Over to Future Years / (from Prior Years)**	4	(29.1)	(2.3)	0.0	(2.3)
19	**Taxable Income After Loss Carry-Over** (line 17 + line 18)		0.0	197.1	46.5	243.6
	Determination of Total Current Income Taxes					
20	**Taxable Income After Loss Carry-Over** (from line 19)		0.0	197.1	46.5	243.6
21	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%
22	**Income Taxes - Current**		0.0	49.3	11.6	60.9
	Determination of Total Deferred Income Taxes					
23	**Total Net Short-Term Temporary Differences** (line 3 + line 6 - line 11 - line 12)		37.9	36.4	13.9	50.2
24	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%
25	**Deferred Income Taxes - Short-Term**		(9.5)	(9.1)	(3.5)	(12.6)
26	**Total Net Long-Term Temporary Differences** (line 9 - line 16 - line 23)		(0.4)	15.9	30.7	46.5
27	**Income Tax Rate - Long-Term**		25.00%	25.00%	25.00%	25.00%
28	**Deferred Income Taxes - Long-Term**		0.1	(4.0)	(7.7)	(11.6)
29	**Tax Loss / Tax Loss Carry-Over** (line 17 or line 18)		(29.1)	(2.3)	0.0	(2.3)
30	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%
31	**Deferred Income Taxes - Tax Loss / Tax Loss Carry-Over**		7.3	0.6	0.0	0.6
32	**Deferred Income Tax - Total** (line 25 + line 28 + line 31)		(2.1)	(12.5)	(11.1)	(23.6)
	Determination of Derivative and Non-Derivative Portions of Total Current Income Taxes					
33	**Taxable Income Before Loss Carry-Over - Impact of Derivative** (from line 15)		(78.7)	0.0	0.0	0.0
34	**Tax Loss Carry-Over From Prior Years - Impact of Derivative** (from line 18)	5	(29.1)	(2.3)	0.0	(2.3)
35	**Taxable Income After Tax Loss Carry-Over From Prior Years - Impact of Derivative** (line 33 +		(107.7)	(2.3)	0.0	(2.3)
36	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%
37	**Income Taxes - Current - Derivative Portion**		(26.9)	(0.6)	0.0	(0.6)
38	**Income Taxes - Current - Non-Derivative Portion** (line 22 - line 37)		26.9	49.9	11.6	61.5
	Determination of Derivative and Non-Derivative Portions of Total Deferred Income Taxes					
39	**Net Long-Term Temporary Differences - Impact of Derivative** (line 7 - line 15)		(45.8)	(76.7)	0.0	(76.7)
40	**Income Tax Rate - Long-Term**		25.00%	25.00%	25.00%	25.00%
41	**Deferred Income Taxes - Long-Term - Derivative Portion**		11.5	19.2	0.0	19.2
42	**Tax Loss Carry-Over - Impact of Derivative** (from line 34)		(29.1)	(2.3)	0.0	(2.3)
43	**Income Tax Rate**		25.00%	25.00%	25.00%	25.00%
44	**Deferred Income Taxes - Tax Loss Carry-Over - Derivative Portion**		7.3	0.6	0.0	0.6
45	**Deferred Income Taxes - Total - Derivative Portion** (line 41 + line 44)		18.7	19.7	0.0	19.7
46	**Deferred Income Taxes - Total - Non-Derivative Portion** (line 32 - line 45)		(20.8)	(32.2)	(11.1)	(43.4)
	Income Tax Rate - Current					
47	**Federal Tax**		15.00%	15.00%	15.00%	15.00%
48	**Provincial Tax**		11.25%	11.25%	11.25%	11.25%
49	**Provincial Manufacturing & Processing Profits Deduction**		-1.25%	-1.25%	-1.25%	-1.25%
50	**Total Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%
	Income Tax Rate - Long-Term					
51	**Federal Tax**		15.00%	15.00%	15.00%	15.00%
52	**Provincial Tax**		10.00%	10.00%	10.00%	10.00%
53	**Provincial Manufacturing & Processing Profits Deduction**		0.00%	0.00%	0.00%	0.00%
54	**Total Income Tax Rate - Long-Term**		25.00%	25.00%	25.00%	25.00%

Notes:
1 All amounts for 2013 and January to October 2014 are presented on a CGAAP basis, as this is the basis used to determine EB-2010-0008 Board-approved forecasts for 2011 and 2012. All amounts for November to December 2014 are presented on a US GAAP basis, which was used to determined the EB-2013-0321 Board approved forecasts.
2 With the exception of lines 1 and 2 (which have been adjusted to CGAAP basis) and internally calculated values at lines 9, 26, 28 and 46, amounts are as shown in EB-2013-0321 Ex. L-1.0-1 Staff-002, Attachment 1, Table 38.
3 Earnings (Loss) Before Tax is derived as the difference between Total Revenue in Ex. H1-1-1, Table 13a, line 11 and Total Costs Before Income Tax at line 19.
4 Amount in col. (b) is calculated as amount in col. (a) plus EB-2013-0321 Ex. G2-2-1, Table 9, line 3, col. (c).
5 As noted in EB-2013-0321, Ex. L-1.0-1 Staff-002, Table 38, Note 41 the full amount of brought forward Bruce tax losses would be utilized in 2012 in the absence of the income tax deduction for the supplemental rent payment reduction in 2012. As such, no losses would be available for utilization in 2013 or 2014.

Numbers may not add due to rounding.

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EB-2014-0370
Exhibit H1
Tab 1
Schedule 1
Table 13c

Table 13c
Amortization of Bruce Lease Net Revenues Variance Account - Derivative Sub-Account ($M)
As at December 31, 2014

Line No.	Particulars	Amount at Dec. 31, 2014
		(a)
	Amount for Recovery in 2015 and 2016 Before Prior Recovery Adjustment	
	2015:	
1	**Forecast Partial Supplemental Rent Rebate**	82.7
2	**Less: Income Tax Impact** (line 1 x tax rate of 25%)	20.7
3	**Net Amount**	62.1
	2016:	
4	**Forecast Partial Supplemental Rent Rebate**	85.4
5	**Less: Income Tax Impact** (line 4 x tax rate of 25%)	21.3
6	**Net Amount**	64.0
7	**Total Amount for Recovery in 2015 and 2016 Before Prior Recovery Adjustment**	126.1
	(line 3 + line 6)	
	Prior Recovery Adjustment	
	2013:	
8	**Amount Recovered per EB-2012-0002 (Prior to EB-2012-0002 Prior Recovery Adjustment)**[1]	60.2
9	**Actual Partial Supplemental Rent Rebate**[2]	78.7
10	**Less: Income Tax Impact** (line 10 x tax rate of 25%)	19.7
11	**Net Amount**	59.0
12	**Prior Recovery Adjustment for 2013** (line 8 - line 11)	1.2
	2014:	
13	**Amount Recovered per EB-2012-0002 (Prior to EB-2012-0002 Prior Recovery Adjustment)**[1]	62.2
14	**Actual Partial Supplemental Rent Rebate**[2]	0.0
15	**Less: Income Tax Impact** (line 10 x tax rate of 25%)	0.0
16	**Net Amount**	0.0
17	**Prior Recovery Adjustment for 2014** (line 13 - line 16)	62.2
18	**Correction of EB-2012-0002 Calculation Error (including interest at OEB-prescribed rate)**[3]	8.9
19	**Total Prior Recovery Adjustment** (line 12 + line 17 + line 18)	72.3
	Amount for Recovery in 2015 and 2016 After Prior Recovery Adjustment	
20	**2015 Amortization** (line 3 - line 19)	(10.2)
21	**2016 Amortization** (line 6)	64.0
22	**Total Amount for Recovery in 2015 and 2016**	53.8

Notes:

1 From EB-2012-0002 Settlement Agreement Ex. M1-1, Att. 2, Table 14c, col. (a), line 6 (2013) and line 9 (2014).

2 From Ex. H1-1-1 Table 13b, line 15, col. (a) for 2013 and sum of cols. (b) and (c) for 2014.

3 As discussed in EB-2013-0321 Ex. H1-1-1, p. 14, lines 16-20 and OPG's letter to the OEB dated September 26, 2013. The amount of the error was $8.9M. Interest added is the sum of Ex. H1-1-1 Table 1a, line 19, col. (f), Ex. H1-1-1 Table 1b, line 19, col. (f), and Ex. H1-1-1 Table 1c, line 33, col. (d).

Table 14
Nuclear Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - 2013 and 2014

Line No.	Particulars	Note	Actual 2013[1]	Current Jan - Oct 2014	Projected Nov - Dec 2014	(b)+(c) Projected Total 2014
			(a)	(b)	(c)	(d)
1	**Nuclear Rider 2013-A / 2014-A ($/MWh)**	2	6.27	4.18	4.18	
2	**Nuclear Rider 2013-B ($/MWh)**	3	0.41			
3	**Interim Nuclear Rider ($/MWh)**	4	4.33			
4	**Interim Period Production Forecast (TWh)**	5	9.0			
5	**Actual Nuclear Production for Jan-Feb 2013 (TWh)**		8.0			
6	**Production Variance (TWh)** (line 4 - line 5)		1.0			
7	**Under Recovery Due to Difference in Interim Period Production ($M)** (line 3 x line 6)		4.4			
8	**Full Year Nuclear Forecast Production Used to Set Rider 2013-A (TWh)**	6	51.0			
9	**Mar 2013 - Dec 2014 Nuclear Production Forecast Used to Set Rider 2013-A and Rider 2014-A (TWh)**	7	42.0	42.7	8.3	51.0
10	**Mar 2013 - Dec 2014 Actual / Projected Nuclear Production (TWh)**		36.7	39.8	8.1	47.9
11	**Actual / Projected Nuclear Production Variance for Mar 2013 - Dec 2014 (TWh)** (line 9 - line 10)		5.3	2.9	0.2	3.0
12	**Under Recovery Due to Difference in Mar 2013 - Dec 2014 Production ($M)** (line 11 x (line 1 + line 2))		35.1	12.1	0.7	12.7
13	**Addition to Variance Account ($M)** (line 7 + line 12)		39.5	12.1	0.7	12.7

Notes:
1 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132 (corrected version filed on June 4, 2014), Attachment 1, Table 14, col. (a).
2 From EB-2012-0002 Payment Amounts Order, App. A, Table 2, line 13, col. (g) for 2013 and col. (h) for 2014.
3 From EB-2012-0002 Payment Amounts Order, App. A, Table 3, col. (b), line 7.
4 From EB-2012-0002 Payment Amounts Order, App. A, Table 3, col. (b), line 2.
5 From EB-2012-0002 Payment Amounts Order, App. A, Table 3, col. (b), line 5.
6 From EB-2012-0002 Payment Amounts Order, App. A, Table 2, col. (g), line 12.
7 Value for 2013 is calculated as line 8 less line 4. Annual value for 2014 is from EB-2012-0002 Payment Amounts Order, App. A, Table 2, col. (g), line 12. Values for January to October 2014 and November to December 2014 are average of the corresponding monthly forecasts found at EB-2012-0002 Ex. L-2-1 Staff-16, Attachment 1, Table 3, lines 1 and 3.

CLEARANCE OF DEFERRAL AND VARIANCE ACCOUNTS

1.0 PURPOSE

This evidence describes OPG's proposed approach for clearing the audited December 31, 2014 balances.

2.0 SUMMARY

OPG is requesting recovery of the audited December 31, 2014 balances in all deferral and variance accounts, except for the Pension and OPEB Cash Versus Accrual Differential Deferral Account and Pension and OPEB Cash Payment Variance Account, adjusted for amounts previously approved for recovery in 2015.

OPG will bring forward the Pension and OPEB Cash Versus Accrual Differential Deferral Account and Pension and OPEB Cash Payment Variance Account in a future application.

In EB-2013-0321 the OEB authorized the recovery of the approved audited December 31, 2013 balances in the Hydroelectric Incentive Mechanism Variance Account, Hydroelectric Surplus Baseload Generation Variance Account, and the hydroelectric portion of the Capacity Refurbishment Variance Account through a hydroelectric payment rider applied to the output from the previously regulated hydroelectric facilities effective January 1, 2015.

The OEB also authorized the recovery of the approved audited December 31, 2013 balances in the Nuclear Development Variance Account and the capital cost portion of the nuclear balance in the Capacity Refurbishment Variance Account through a nuclear payment rider applied to the output from the nuclear facilities effective January 1, 2015.

For all other existing accounts, the December 31, 2012 balances were approved by the OEB in EB-2012-0002 as discussed in Ex. H1-1-1.

Amortization amounts and payment riders described in this exhibit and accompanying tables are calculated based on a November 2014 projection of the December 31, 2014 balances, adjusted for amortization already authorized for 2015 for the accounts listed above. Given that this projection was made late in the year, OPG expects it to be very close to the final figures that will appear in the audited December 31, 2014 balances that OPG expects to file, along with a calculation of the resulting payment riders in February 2015.

The adjustment of balances for amortization already authorized for 2015 is shown at Ex. H1-2-1 Tables 1 and 2, columns (a) through (c).

The methodology for the proposed recovery of the balances adjusted for previously authorized 2015 amortization is described in section 3.0. Proposals regarding effective dates, recovery periods and production forecast to be used to calculate the riders are presented in section 4.0. The calculation of the proposed riders based on projected December 31, 2014 balances is discussed in section 5.0.

3.0 METHODOLOGY

OPG proposes to calculate separate riders for the output of all regulated hydroelectric facilities and the nuclear facilities, in the form of $/MWh rates consistent with the OEB's decisions and Payment Amounts Orders in EB-2013-0321, EB-2012-0002 and EB-2010-0008**.**

As before, riders are calculated using the following three steps.

First, a recovery period is determined for each account (or sub-account) to be cleared.

Second, based on each account's recovery period and the balance in the account, the amount to be amortized over the period is determined. As noted in section 2.0, above, balances to be cleared will be determined by adjusting the audited December 31, 2014 balances for amortization already authorized for 2015 by the OEB in EB-2013-0321.

The only exception to this second step is the Bruce Lease Net Revenues Variance Account – Derivative Sub-Account. OPG proposes to continue with the method of determining the amortization amount for the Derivative Sub-Account as per the OEB-approved Settlement Agreement in EB-2012-0002. This method requires the amount cleared each year to be equal to the amount of the supplemental rent rebate forecast to be payable to Bruce Power for that year by OPG and associated income tax impacts, adjusted by the difference between amounts previously recovered in respect of the balance of the Sub-Account, and the actual rent rebates paid by OPG to Bruce Power and associated income taxes.

As shown in Ex. H1-1-1 Table 13c, OPG forecasts supplemental rent rebates, net of associated income tax impacts, of $62.1M in 2015 and $64.0M in 2016. The EB-2012-0002 payment riders reflected forecast supplemental rent rebates, net of associated income tax impacts, for 2013 and 2014. OPG made a supplement rent rebate payment for 2013, but does not expect to make such a payment for 2014. As such, as shown in Ex. H1-1-1 Table 13c, the 2015 proposed amortization for the Derivative Sub-Account is reduced by the 2014 amortization authorized in EB-2012-0002. The 2015 proposed amortization is also reduced for the difference of $1.2M between the forecast and actual rebate made for 2013, net of associated income tax impacts. Finally, the 2015 proposed amortization has been reduced by $8.9M (including interest at the OEB-prescribed rate) to correct an earlier error in the EB-2012-0002 calculation as explained in EB-2013-0321 Ex. H1-1-1, page 14, lines 16-20 and described in detail in OPG's letter to the OEB dated September 26, 2013**.** The resulting amortization shown in Ex. H1-2-1, Table 2, line 6 is a credit to customers of $10.2M in 2015 and an amount to be recovered of $64.0M in 2016.

The third step in the calculation of the payment rider is to divide the total amortization amounts for all accounts to be cleared during the period by the forecast energy production to determine the payment rider.

OPG proposes a common rider for the previously and newly regulated hydroelectric facilities. This rider is calculated by dividing the combined amounts to be cleared for all regulated hydroelectric facilities by the combined production forecast for all of these facilities. OPG views the use of a common rider for regulated hydroelectric facilities as consistent with the eventual consolidation of the previously and newly regulated hydroelectric assets when determining future payment amounts.

4.0 RECOVERY PROPOSALS

4.1 Recovery Periods

OPG proposes to calculate amortization based on a recovery period of 18 months commencing July 1, 2015 for all accounts with the exceptions described below.

The Bruce Lease Net Revenues Variance Account – Derivative Sub-Account is proposed to be cleared as described in section 3.0, above.

Amortization for the December 31, 2014 balance of the Pension and OPEB Cost Variance Account – Future Recovery component is proposed to be based on a period of 10 years, consistent with the remaining period of the 12-year amortization period agreed to in the OEB-approved EB-2012-0002 Settlement Agreement for this component.

For the Pension and OPEB Cost Variance Account – Post 2012 Additions component, OPG proposes amortization over 24 months commencing July 1, 2015.

4.2 Production Forecast

Consistent with the methodology approved by the OEB in EB-2012-0002, OPG proposes to calculate the payment amount riders using the production forecasts approved in the most recent rate proceeding, EB-2013-0321. Any differences between forecast and actual production will continue to be addressed by entries into the Hydroelectric Over/Under Recovery Variance Account and the Nuclear Over/Under Recovery Variance Account.

In calculating the nuclear payment rider, OPG is using a production value of 71.7 TWh, which is 18/24 of the EB-2013-0321 approved two-year production forecast of 95.6TWh.

In calculating the regulated hydroelectric rider, OPG is using a production value of 48.8TWh, which is the sum of 18/24 of the two-year production forecast of 41.1TWh for the previously regulated hydroelectric facilities and the July 1, 2014 to December 31, 2015 18-month production forecast of 17.9TWh for the newly regulated hydroelectric facilities approved in EB-2013-0321.

5.0 CALCULATION OF RIDERS

5.1 Regulated Hydroelectric

The method of calculating the regulated hydroelectric payment rider is as shown in Ex. H1-2-1, Table 1 using projected December 31, 2014 account balances, adjusted for the 2015 amortization already approved in EB-2013-0321. The resulting balances to be recovered in 2015 and 2016 are $184.5M. The rider would be $3.78/MWh. The actual rider will be set using audited December 31, 2014 balances.

5.2 Nuclear

The method for calculating the nuclear payment rider is as shown in Ex. H1-2-1, Table 2 using projected December 31, 2014 account balances, adjusted for the 2015 amortization already approved in EB-2013-0321. The resulting balances to be recovered in 2015 and 2016 are $1,131.1M. The rider would be $15.78/MWh. The actual rider will be set using audited December 31, 2014 balances. As noted in section 2.0 above, given that the projection of both the nuclear and regulatory hydroelectric balances was made late in the year, OPG expects it to be very close to the final figures.

Numbers may not add due to rounding.

Table 1

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

Line No.	Account	Projected Balance at December 31, 2014[1]	EB-2013-0321 Board Approved Amortization 2015[2]	(a)-(b) 2014 Balance Less 2015 Approved Amortization	Recovery Period (Months)	Amortization Jul - Dec 2015	Amortization Jan - Dec 2016	(e)+(f) Amortization Jul 2015 - Dec-16	(c)-(g) Unamortized Balance At Dec 31, 2016
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Hydroelectric Water Conditions Variance**	12.7	0.0	12.7	18	4.2	8.4	12.7	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	(10.6)	0.0	(10.6)	18	(3.5)	(7.0)	(10.6)	0.0
3	**Hydroelectric Incentive Mechanism Variance**	(7.5)	(5.0)	(2.5)	18	(0.8)	(1.7)	(2.5)	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**	52.0	19.2	32.8	18	10.9	21.9	32.8	0.0
5	**Income and Other Taxes Variance - Hydroelectric**	(0.1)	0.0	(0.1)	18	(0.0)	(0.1)	(0.1)	0.0
6	**Capacity Refurbishment Variance - Hydroelectric**	232.6	112.7	119.9	18	40.0	79.9	119.9	0.0
7	**Pension and OPEB Cost Variance - Hydroelectric - Historic**	0.0	0.0	0.0	18	0.0	0.0	0.0	0.0
8	**Pension and OPEB Cost Variance - Hydroelectric - Future**	10.5	0.0	10.5	120	1.1	1.1	2.1	8.4
9	**Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions**	35.5	0.0	35.5	24	8.9	17.7	26.6	8.9
10	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	3.7	0.0	3.7	18	1.2	2.5	3.7	0.0
11	**Total** (lines 1 though 10)	328.8	127.0	201.8				184.5	17.3
12	**Production[3] (TWh)**							48.8	
13	**Regulated Hydroelectric Payment Rider ($/MWh)** (line 11 / line 12)							3.78	

Notes:

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

2 From EB-2013-0321 Payment Amounts Order Appendix E, Table 1, line 13, col. (e).

3 Board-approved 2014-2015 previously regulated hydroelectric production from EB-2013-0321 Payment Amounts Order, App. B, Table 1, line 2 multiplied by 18 months divided by 24 months, plus July 1, 2014-December 31, 2015 newly regulated hydroelectric production from EB-2013-0321 Payment Amounts Order, App. C, Table 1, line 2, col. (c).

Numbers may not add due to rounding.

Table 2
Calculation of Deferral and Variance Account Recovery Payment Rider - Nuclear ($M)

Line No.	Account	Projected Balance at December 31, 2014[1]	EB-2013-0321 Board Approved Amortization 2015[2]	(a)-(b) 2014 Balance Less 2015 Approved Amortization	Recovery Period (Months)	Amortization Jul - Dec 2015	Amortization Jan - Dec 2016	(e)+(f) Amortization Jul 2015 - Dec-16	(c)-(g) Unamortized Balance At Dec 31, 2016
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Nuclear Liability Deferral**	286.3	0.0	286.3	18	95.4	190.9	286.3	0.0
2	**Nuclear Development Variance**	59.0	56.5	2.5	18	0.8	1.7	2.5	0.0
3	**Ancillary Services Net Revenue Variance - Nuclear**	1.7	0.0	1.7	18	0.6	1.1	1.7	0.0
4	**Capacity Refurbishment Variance - Nuclear - Capital Portion**	13.1	5.7	7.4	18	2.5	5.0	7.4	0.0
5	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**	6.7	0.0	6.7	18	2.2	4.4	6.7	0.0
6	**Bruce Lease Net Revenues Variance - Derivative Sub-Account**	129.9	0.0	129.9	n/a	(10.2)	64.0	53.8	76.1
7	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002**	37.3	0.0	37.3	18	18.7	18.7	37.3	0.0
8	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions**	126.8	0.0	126.8	18	42.3	84.5	126.8	0.0
9	**Income and Other Taxes Variance - Nuclear**	(8.5)	0.0	(8.5)	18	(2.8)	(5.7)	(8.5)	0.0
10	**Pension and OPEB Cost Variance - Nuclear - Historic**	0.0	0.0	0.0	18	0.0	0.0	0.0	0.0
11	**Pension and OPEB Cost Variance - Nuclear - Future**	214.7	0.0	214.7	120	21.5	21.5	42.9	171.7
12	**Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions**	678.6	0.0	678.6	24	169.7	339.3	509.0	169.7
13	**Pickering Life Extension Depreciation Variance**	7.8	0.0	7.8	18	2.6	5.2	7.8	0.0
14	**Nuclear Deferral and Variance Over/Under Recovery Variance**	57.4	0.0	57.4	18	19.1	38.2	57.4	0.0
15	**Total** (lines 1 through 14)	1,610.7	62.2	1,548.5				1,131.1	417.4
16	**Forecast 2015 Production[3] (TWh)**							71.7	
17	**Nuclear Payment Rider ($/MWh)** (line 15 / line 16)							15.78	

Notes:
1 From Ex. H1-1-1 Table 1.
2 From EB-2013-0321 Payment Amounts Order Appendix F, Table 1, line 16, col. (e).
3 Board-approved 2014-2015 nuclear production from EB-2013-0321 Payment Amounts Order, App. D, Table 1, line 2 multiplied by 18 months divided by 24 months.

CONTINUATION OF EXISTING DEFERRAL AND VARIANCE ACCOUNTS

1.0 PURPOSE

OPG is not proposing any new deferral or variance accounts in this application. OPG also is not proposing any changes to the accounts that the OEB approved for continuation or established in EB-2013-0321. All of these accounts are fully described in Appendix G to the EB-2013-0321 Payment Amounts Order. For reference, a copy of that document is attached to this exhibit as Attachment 1.

Appendix G: Deferral and Variance Accounts

CLEARANCE OF EXISTING DEFERRAL AND VARIANCE ACCOUNTS

With respect to the deferral and variance accounts established by O. Reg. 53/05 and the Board's decisions and orders in EB-2007-0905, EB-2009-0038, EB-2009-0174, EB-2010-0008, EB-2011-0090, EB-2011-0432 and EB-2012-0002, the Board approves the recovery of the December 31, 2013 balances in the accounts or portions of accounts, as provided the following table, over the twelve month period, January 1, 2015 through December 31, 2015.

Chart G-1

Account	Approved December 31, 2013 Balances ($M)
Hydroelectric Incentive Mechanism Variance	(5.0)
Hydroelectric Surplus Baseload Generation Variance	19.2
Capacity Refurbishment Variance – Hydroelectric	112.7
Nuclear Development Variance	56.5
Capacity Refurbishment Variance – Nuclear - Capital Portion	5.7

The Board approves OPG's recovery of the above approved balances in the previously regulated hydroelectric deferral and variance accounts using a payment amount rider. A payment rider of $6.04/MWh, as determined in Appendix E, Table 1, shall apply to OPG's previously regulated hydroelectric production for the period from January 1, 2015 to December 31, 2015.

The Board approves OPG's recovery of the above approved balances in the nuclear deferral and variance accounts using a payment amount rider. A payment rider of $1.33/MWh, as determined in Appendix F, Table 1, shall apply to OPG's nuclear production for the period from January 1, 2015 to December 31, 2015.

For the period January 1, 2014 to October 31, 2014, OPG shall continue to record entries into the deferral and variance accounts established by O. Reg. 53/05 and the applicable previous decisions and orders of the Board pursuant to the methodologies established by O. Reg. 53/05 and such decisions and orders.

CONTINUING DEFERRAL AND VARIANCE ACCOUNTS

Unless otherwise stated in this Order, effective November 1, 2014, OPG shall continue to record entries into the deferral and variance accounts authorized by O. Reg. 53/05 and the applicable decisions and orders of the Board pursuant to the methodologies established by O. Reg. 53/05 and such decisions and orders, as outlined in OPG's Application at Ex. H1-3-1 and as summarized below. Unless otherwise stated in this Order, for the period from November 1, 2014 to December 31, 2014, OPG shall continue to record amortization entries into the applicable deferral and variance accounts pursuant to the EB-2012-0002 Payment Amounts Order.

Effective November 1, 2014, OPG shall record entries into deferral and variance accounts listed below as follows:

Hydroelectric Water Conditions Variance Account

The Hydroelectric Water Conditions Variance Account was originally approved in EB-2007-0905 for the previously regulated hydroelectric facilities. OPG shall continue this account and maintain separate sub-accounts for the previously and newly regulated hydroelectric prescribed assets. The account shall apply to the previously regulated hydroelectric facilities and to 21 of the newly regulated hydroelectric facilities. These 21 newly regulated hydroelectric facilities are listed in EB-2013-0321, Ex. E1-1-1 Appendix 1.

For the previously regulated hydroelectric facilities, OPG will continue to determine the hydroelectric production impact of changes in water conditions by entering the actual flow values into the same production forecast models used to calculate the Board-approved production forecast, holding all other variables constant. Deviations from forecast will be determined as the difference between the calculated production resulting from entering actual flows for the month into the forecast model and the energy production forecast approved by the Board. The revenue impact of the production variance recorded in the account for the previously regulated hydroelectric facilities will continue to be determined by multiplying the deviation from forecast, as described above, by the approved payment amount for these facilities. For production from the previously regulated hydroelectric facilities, OPG shall determine the revenue impact of the production variance by multiplying the deviation from forecast, as described above, by the approved payment amount of $40.20/MWh.

Energy production forecasts for 21 of the newly regulated hydroelectric plants, listed in EB-2013-0321, Ex. E1-1-1 Appendix 1, are produced using similar computer models to those used to forecast production for the previously regulated hydroelectric facilities. The models convert forecast water availability to forecast energy production using historical median monthly flows as the basis for determining the monthly energy production forecasts. Similar to the previously regulated hydroelectric facilities, for these 21 facilities, OPG shall compute deviations of actual monthly flows from these historical median monthly flows in order to determine the production variance for purposes of the Hydroelectric Water Conditions Variance Account. OPG shall determine the revenue impact of the production variance by multiplying the deviation from forecast, as described above, by the approved payment amount of $41.93/MWh.

In respect of production from the previously and the applicable 21 newly regulated hydroelectric facilities, OPG shall also record in this account changes in the gross revenue charge costs reflected in the revenue requirement approved by the Board, as a result of differences between imputed production from actual flows and forecast energy production described above. OPG shall determine amounts to be recorded in this account by multiplying the production deviation as described above by the applicable gross revenue charge rates.

In respect of production from the previously regulated hydroelectric facilities, OPG shall also record in this account any variations from the amounts payable to the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal reflected in the revenue requirement approved by the Board.

In respect of production from the applicable 21 newly regulated hydroelectric facilities, OPG shall also record in the account any variances from the amounts payable to the Government of Quebec for water rentals reflected in the revenue requirement approved by the Board.

Ancillary Services Net Revenue Variance Account – Hydroelectric

The Ancillary Services Net Revenue Variance Account – Hydroelectric was originally approved in EB-2007-0905 for the previously regulated hydroelectric facilities. The account shall apply to the previously and newly regulated hydroelectric facilities. OPG shall maintain separate sub-accounts for the previously and newly regulated hydroelectric prescribed assets.

OPG shall compare actual hydroelectric ancillary services net revenue to the forecast amount reflected in the revenue requirement approved by the Board (the "reference amount"). The monthly reference amount shall be 1/24 of the total forecast amount of $110.9M ($65.1M for the previously regulated hydroelectric facilities and $45.8M for the newly regulated hydroelectric facilities) for 2014 and 2015 underpinning the two-year revenue requirement approved by the Board. The resulting monthly reference amount shall be $4.62M ($2.71M for the previously regulated hydroelectric facilities and $1.91M for the newly regulated hydroelectric facilities). The difference shall be recorded in this variance account. The ancillary services for the regulated hydroelectric operations include black start capability, operating reserve, regulation service (formerly referred to as automatic generation control), and reactive support/voltage control service.

OPG shall ensure that amounts recorded in the account do not include those that OPG indicated it is not seeking to recover from, or refund to, ratepayers as part of the differences between the revenue requirement in its pre-filed evidence dated September 27, 2013 and the information based on OPG's 2014-2016 Business Plan. These amounts are outlined in OPG's Impact Statement dated December 6, 2013, as found at EB-2013-0321, Ex. N1-1-1 Chart 1.

Income and Other Taxes Variance Account

The Income and Other Taxes Variance Account was originally approved in EB-2007-0905. This account shall continue, and OPG shall attribute amounts recorded in the account to each of the previously regulated hydroelectric, newly regulated hydroelectric and nuclear prescribed assets.

This account shall continue to record the financial impact on the revenue requirement approved by the Board (the "reference amount") of:

- Any differences in payments in lieu of corporate income or capital taxes that result from a legislative or regulatory change to the tax rates or rules of the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) (formerly the *Corporations Tax Act* (Ontario)), as modified by the regulations under the *Electricity Act, 1998*, and any differences in payments in lieu of property tax to the Ontario Electricity Financial Corporation that result from changes to the regulations under the *Electricity Act, 1998*.

- Any differences in municipal property taxes that result from a legislative or regulatory change to the tax rates or rules for OPG's prescribed assets under the *Assessment Act, 1990*.
- Any differences in payments in lieu of corporate income or capital taxes that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities, or court decisions on other taxpayers.
- Any differences in payments in lieu of income or capital taxes that result from assessments or re-assessments (including re-assessments associated with the application of the tax rates and rules to OPG's regulated operations or changes in assessing or administrative policy including court decisions on other taxpayers).

The income tax provision reflected in the revenue requirement approved by the Board shall be used to calculate any variances in income taxes recorded in the Income and Other Taxes Variance Account. The income tax provision reflected in the revenue requirement approved by the Board is calculated in Appendix A, Tables 7 and 8. The monthly reference amount shall be 1/24 of the total forecast amount of $115.9M for 2014 and 2015 underpinning the two-year revenue requirement approved by the Board. The monthly reference amount shall be $4.83M.

<u>Tax Loss Variance Account</u>

The Tax Loss Variance Account was originally approved in EB-2009-0038. OPG shall continue to record only interest and amortization in the Tax Loss Variance Account during the period from November 1, 2014 to December 31, 2014. The previously regulated hydroelectric and nuclear balances remaining in this account at December 31, 2014 shall be transferred to the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and the Nuclear Deferral and Variance Over/Under Recovery Variance Account, respectively. Following this transfer, the Tax Loss Variance Account shall be terminated on December 31, 2014.

<u>Impact for USGAAP Deferral Account</u>

The Impact for USGAAP Deferral Account was originally approved in EB-2011-0432. OPG shall continue to record only interest and amortization in the Impact for USGAAP Deferral Account during the period from November 1, 2014 to December 31, 2014. The previously regulated hydroelectric and nuclear balances remaining in this account at December 31, 2014 shall be transferred to the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and the Nuclear Deferral and Variance Over/Under Recovery Variance Account, respectively. Following this transfer, the Impact for USGAAP Deferral Account shall be terminated on December 31, 2014.

Pension and OPEB Cost Variance Account

The Pension and OPEB Cost Variance Account was originally approved in EB-2011-0090. This account recorded the difference between (i) the pension and OPEB costs, plus related income tax PILs, reflected in the current revenue requirement approved by the Board (the "reference amount"), and (ii) OPG's actual pension and OPEB costs, and associated income tax impacts, for the previously regulated hydroelectric and nuclear prescribed generation facilities. Actual pension and OPEB costs used in the calculation of the difference were to be calculated using the same accounting standards as those used to derive the reference amount.

In EB-2012-0002, the approved December 31, 2012 balance in the Pension and OPEB Cost Variance Account was split into the Historic Recovery and Future Recovery components. In EB-2013-0321, OPG identified a third component, which comprised additions recorded in the account subsequent to December 31, 2012. OPG shall continue to track these components separately, with any remaining balance of the Historic Recovery component at December 31, 2014 transferred to the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and Nuclear Deferral and Variance Over/Under Recovery Variance Account, as applicable.

Effective November 1, 2014, OPG will record only amortization in this account. OPG shall not record any interest on the balance of this account.

Hydroelectric Incentive Mechanism Variance Account

The Hydroelectric Incentive Mechanism Variance Account was originally approved in EB-2010-0008 for the previously regulated hydroelectric facilities. Going forward, the account shall apply to the previously and newly regulated hydroelectric facilities. OPG shall maintain separate sub-accounts for the previously and newly regulated hydroelectric prescribed assets.

In its decision, the Board found that the current hydroelectric incentive mechanism ("HIM") has encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices. The Board has maintained the current structure of the incentive mechanism (and the corresponding variance account) but has specified that the unintended interaction of the HIM due to surplus baseload generation ("SBG") conditions be eliminated. The Board directed OPG to achieve this by changing its monthly average hourly production threshold calculation used by the IESO for purposes of settling HIM revenues.

The Board also found that HIM net revenues are to continue to be shared between ratepayers and OPG using a 50:50 ratio. The resulting annual revenue requirement offset with respect to the HIM net revenues will be $25.5M for 2014. The annual revenue requirement offset for 2015 will be $29M. Accordingly, during the period from November 1, 2014 to December 31, 2014, the Hydroelectric Incentive Mechanism Variance Account will record a credit to ratepayers equal to 50 per cent of OPG's total HIM net revenues from the prescribed hydroelectric facilities above $8.5M, being 2/12 of the 2014 annual threshold of $51M. During the period from January 1, 2015 to December 31, 2015, OPG shall record a credit to ratepayers equal to 50 per cent of OPG's total HIM net revenues above $58M.

Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric Surplus Baseload Generation Variance Account was originally approved in EB-2010-0008 for the previously regulated hydroelectric facilities. OPG shall continue this account and shall maintain separate sub-accounts for the previously and newly regulated hydroelectric prescribed assets.

This account shall continue to record the financial impact of foregone production at the prescribed hydroelectric facilities due to SBG conditions. The account shall apply to the previously regulated hydroelectric facilities and to 21 of the newly regulated hydroelectric facilities. These 21 newly regulated hydroelectric facilities are listed in EB-2013-0321, Ex. E1-1-1 Appendix 1.

OPG shall determine the revenue impact of SBG conditions by multiplying the foregone production volume by the approved previously regulated hydroelectric payment amount of $40.20/MWh or the approved newly regulated hydroelectric payment amount of $41.93/MWh, as applicable. The resulting amount shall be recorded in the Hydroelectric Surplus Baseload Generation Variance Account.

In respect of production foregone due to SBG conditions at the previously and the 21 applicable newly regulated hydroelectric facilities, OPG shall also record in this account changes in the gross revenue charge costs reflected in the revenue requirement approved by the Board. OPG shall determine amounts to be recorded in this account by multiplying the production volume foregone at its prescribed hydroelectric facilities due to SBG conditions by the applicable gross revenue charge rates.

In respect of production foregone due to SBG conditions at the previously regulated hydroelectric facilities, OPG shall also record in this account any variations from the amounts payable to the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal reflected in the revenue requirement approved by the Board. In respect of foregone production at the 21 applicable newly regulated hydroelectric facilities, OPG shall also record in the account any variances from the amounts payable to the Government of Quebec for water rentals reflected in the revenue requirement approved by the Board.

Changing the monthly average hourly production threshold calculation associated with the HIM by removing any contribution from production volume foregone due to SBG conditions eliminates the need for any rebating back to ratepayers of unintended benefits of this interaction through the Hydroelectric Surplus Baseload Generation Variance Account.

Hydroelectric Deferral and Variance Over/Under Recovery Variance Account

The Hydroelectric Deferral and Variance Over/Under Recovery Variance Account was originally approved in EB-2009-0174 for the previously regulated hydroelectric facilities. The account shall apply to the previously and newly regulated hydroelectric facilities. OPG shall maintain separate sub-accounts for the previously and newly regulated hydroelectric prescribed assets.

This account shall record the differences between the amounts approved for recovery in the hydroelectric deferral and variance accounts and the actual amounts recovered based on actual regulated hydroelectric production and approved riders. The account shall also include the transfer of the previously regulated hydroelectric balances in the Tax Loss Variance Account and the Impact for USGAAP Deferral Account upon their expiry on December 31, 2014, the previously regulated hydroelectric balance of the Historic Recovery component of the Pension and OPEB Cost Variance Account at December 31, 2014, and other accounts as they may expire from time to time.

Nuclear Liability Deferral Account

The Nuclear Liability Deferral Account was originally approved in EB-2007-0905. This account shall continue to record the revenue requirement impact of any change in OPG's nuclear decommissioning liability arising from an approved reference plan measured against the forecast impact reflected in the revenue requirement approved by the Board. OPG shall not record the revenue requirement impact of a change in its nuclear decommissioning liability associated with its nuclear obligations related to the Bruce facilities in this account. OPG shall record the return on rate base in the account using the weighted average accretion rate on OPG's nuclear liabilities of 5.37%.

The "nuclear decommissioning liability" shall be defined as "the liability of Ontario Power Generation Inc. for decommissioning its nuclear generating facilities and the management of its nuclear waste and nuclear fuel." An "approved reference plan" shall be defined as "a reference plan, as defined in the Ontario Nuclear Funds Agreement, which has been approved by Her Majesty the Queen in the right of Ontario in accordance with that agreement."

OPG shall not record any interest on the balance of the Nuclear Liability Deferral Account.

Nuclear Development Variance Account

The Nuclear Development Variance Account was originally approved in EB-2007-0905. This account shall continue to record variances between the actual non-capital costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities and those forecast costs and firm financial commitments reflected in the revenue requirement approved by the Board (the "reference amount"). The monthly reference amount shall be 1/24 of the total forecast amount of $0 underpinning the two-year revenue requirement approved by the Board for 2014 and 2015. The monthly reference amount shall be $0.

Ancillary Services Net Revenue Variance Account – Nuclear

The Ancillary Services Net Revenue Variance Account – Nuclear was originally approved in EB-2007-0905. OPG shall compare actual nuclear ancillary services net revenue to the forecast amount reflected in the revenue requirement approved by the Board (the "reference amount"). The monthly reference amount shall be 1/24 of the total forecast amount $3.4M for 2014 and 2015 underpinning the two-year revenue requirement of approved by the Board. The monthly reference amount shall be $0.14M. The difference shall be recorded in this variance account. The ancillary services for nuclear operations include reactive support/voltage control service.

OPG shall ensure that amounts recorded in the account do not include those that OPG indicated it is not seeking to recover from, or refund to, ratepayers as part of the differences between the revenue requirement in its pre-filed evidence dated September 27, 2013 and the information based on OPG's 2014-2016 Business Plan. These amounts are outlined in OPG's Impact Statement dated December 6, 2013, as found at EB-2013-0321, Ex. N1-1-1 Chart 1.

Capacity Refurbishment Variance Account

The Capacity Refurbishment Variance Account was originally approved in EB-2007-0905. This account shall continue and will record variances between the actual capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a prescribed generation facility referred to in O. Reg. 53/05 section 2 and those forecast costs and firm financial commitments reflected in the revenue requirement approved by the Board for 2014 and 2015. This account shall continue to include assessment costs and pre-engineering costs and commitments.

OPG shall separately track amounts recorded in this variance account for each of the previously regulated hydroelectric, newly regulated hydroelectric and nuclear prescribed assets.

OPG shall ensure that amounts recorded in the account do not include those that OPG indicated it is not seeking to recover from, or refund to, ratepayers as part of the differences between the revenue requirement in its pre-filed evidence dated September 27, 2013 and the information based on OPG's 2014-2016 Business Plan. These amounts are outlined in OPG's Impact Statement dated December 6, 2013, as found at EB-2013-0321, Ex. N1-1-1 Chart 1.

Bruce Lease Net Revenues Variance Account

The Bruce Lease Net Revenues Variance Account was originally approved in EB-2007-0905. This account shall continue to capture differences between (i) the forecast revenues and costs related to the Bruce lease that are factored into the nuclear revenue requirement approved by the Board (the "reference amount"), and (ii) OPG's actual revenues and costs in respect of the Bruce facilities. The monthly reference amount shall be 1/24 of the total forecast amount of $80.3M underpinning the two-year revenue requirement approved by the Board for 2014 and 2015. The monthly reference amount shall be $3.35M.

The variance recorded in this account shall be measured by comparing the Bruce lease revenues net of costs credited to customers monthly through the approved nuclear payment amount of $59.29/MWh to the actual monthly Bruce lease revenues net of costs realized by OPG. The monthly Bruce lease revenues net of costs credited to customers shall continue to be equal to the rate of recovery reflected in the nuclear revenue requirement approved by the Board multiplied by OPG's actual nuclear production. The rate of recovery shall be calculated by dividing the 24-month forecast Bruce lease net revenues approved by the Board for 2014 and 2015 by the 24-month forecast nuclear production approved by the Board for 2014 and 2015.

OPG shall ensure that amounts recorded in the account do not include those that OPG indicated it is not seeking to recover from, or refund to, ratepayers as part of the differences between the revenue requirement in its pre-filed evidence dated September 27, 2013 and the information based on OPG's 2014-2016 Business Plan. These amounts are outlined in OPG's Impact Statement dated December 6, 2013, as found at EB-2013-0321, Ex. N1-1-1 Chart 1.

The account balance shall not attract interest for the period from November 1, 2014 to December 31, 2014.

This account will continue to have two sub-accounts as follows:

Derivative Sub-Account

The sub-account balance relates to the derivative liability for the conditional supplemental rent rebate provision of the Bruce lease (including associated income tax impacts on Bruce lease net revenues calculated in accordance with generally accepted accounting principles for unregulated entities) and the rent rebates associated with supplemental rent revenue.

The amount to be cleared for this sub-account in respect of each year 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.

To the extent that the actual supplemental rent rebate amounts paid to Bruce Power differ from the approved forecast amounts used to establish amounts to be recovered by OPG in respect of this sub-account, such differences shall be reflected in the Derivative Sub-Account in order to be carried forward to adjust amortization amounts the next time the sub-account balance is cleared.

Non-Derivative Sub-Account

The sub-account balance relates to the non-derivative aspects of the account.

The cost impact of any changes in OPG's liability for decommissioning the Bruce nuclear generating facilities and the management of nuclear waste and nuclear fuel related to the Bruce stations shall continue to be recorded in the Non-Derivative Sub-Account of the Bruce Lease Net Revenues Variance Account.

Pickering Life Extension Depreciation Variance Account

The Pickering Life Extension Depreciation Variance Account was originally approved in EB-2012-0002 to record a 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, for depreciation purposes, of the Pickering stations. As the payment amounts authorized in this Order reflect these revised service lives, effective November 1, 2014, OPG will record only amortization in the account. No interest shall be recorded on the balance in this account.

Nuclear Deferral and Variance Over/Under Recovery Variance Account

The Nuclear Deferral and Variance Over/Under Recovery Variance Account was originally approved in EB-2009-0174. This account shall continue to record the differences between the amounts approved for recovery in the nuclear deferral and variance accounts and the actual amounts recovered based on actual nuclear production and approved riders. The account shall also include the transfer of the nuclear portion of the balances in the Tax Loss Variance Account and the Impact for USGAAP Deferral Account upon their expiry on December 31, 2014, the balance of the nuclear portion of the Historic Recovery component of the Pension and OPEB Cost Variance Account at December 31, 2014, and other accounts as they may expire from time to time.

NEW DEFERRAL AND VARIANCE ACCOUNTS

Effective November 1, 2014, OPG shall establish and record entries into deferral and variance accounts listed below as follows:

Gross Revenue Charge Variance Account

The Gross Revenue Charge Variance Account will record the cost impact of a gross revenue charge reduction under Ontario Regulation 124/02, once approved by the Ontario Ministry of Natural Resources and Forestry, pertaining to production increases at OPG's Sir Adam Beck plants due to the operation of the new Niagara tunnel. The impact shall be determined by applying the approved reduction under Ontario Regulation 124/02 to the forecast gross revenue charge costs included in the revenue requirement approved by the Board for 2014 and 2015, holding all other variables constant. The impact shall be calculated as of the later of November 1, 2014 and the effective date of the approved gross revenue charge reduction.

Pension & OPEB Cash Payment Variance Account

The Pension & OPEB Cash Payment Variance Account will record the difference between OPG's actual registered pension plan contributions and other post employment benefit plan payments (including the long-term disability benefit plan) attributed to the prescribed generating facilities, and such forecast amounts reflected in the revenue requirement approved by the Board (the “reference amount”). With respect to OPG’s forecast registered pension plan contributions, the monthly reference amount shall be 1/24 of the total forecast contribution of $651.5M for 2014 and 2015 ($561.2M for the nuclear facilities, $31.7M for the previously regulated hydroelectric facilities, and $58.6M for the newly regulated hydroelectric facilities) underpinning the two-year revenue requirement approved by the Board. With respect to OPG’s forecast other post employment benefit plan payments (including the long-term disability benefit plan), the monthly reference amount shall be 1/24 of the total forecast benefit payments of $185.4M for 2014 and 2015 ($159.8M for the nuclear facilities, $9.0M for previously regulated hydroelectric facilities, and $16.7M for the newly regulated hydroelectric facilities) underpinning the two-year revenue requirement approved by the Board. The resulting monthly reference amount shall be $27.15M for OPG’s registered pension plan contributions ($23.38M for the nuclear facilities, $1.32M for the previously regulated hydroelectric facilities, and $2.44M for the newly regulated hydroelectric facilities) and $7.73M for OPG’s other post employment benefit plan payments ($6.66M for the nuclear facilities, $0.38M for the previously regulated hydroelectric facilities, and $0.69M for the newly regulated hydroelectric facilities).

OPG shall separately track amounts recorded in this variance account for each of the previously regulated hydroelectric, newly regulated hydroelectric, and nuclear prescribed assets.

<u>Pension & OPEB Cash Versus Accrual Differential Deferral Account</u>

The Pension & OPEB Cash Versus Accrual Differential Deferral Account will record differences between (i) OPG’s actual pension and OPEB costs for its prescribed generating facilities determined using the accrual accounting method applied in OPG’s audited consolidated financial statements, and (ii) OPG’s actual registered pension plan contributions and other post employment benefit plan payments (including the long-term disability benefit plan) attributed to OPG’s prescribed generating facilities. The deferral account shall also record any associated income tax impacts.

OPG shall separately track amounts recorded in this deferral account for each of the previously regulated hydroelectric, newly regulated hydroelectric, and nuclear prescribed assets. No interest shall be recorded on the balance of this account.

INTEREST

Except where otherwise stated, effective November 1, 2014, OPG shall record interest on the balances in all deferral and variance accounts using the interest rates set by the Board from time to time pursuant to the Board's interest rate policy. OPG shall apply simple interest to the opening monthly balance of the accounts until the balances are fully recovered or refunded.

REGULATED HYDROELECTRIC AND NUCLEAR RIDERS

1.0 PURPOSE

This evidence presents OPG's requested payment riders for the regulated hydroelectric and nuclear facilities.

2.0 PAYMENT RIDERS

OPG is seeking approval of a payment rider for the purposes of clearing approved Hydroelectric deferral and variance account balances effective July 1, 2015. The final rider will be set using audited 2014 account balances. Based on current projected balances, a rider of $3.78/MWh would result. The basis for the requested Hydroelectric payment rider is presented in Ex. H1-2-1 Table 1.

OPG is seeking approval of a payment rider for the purposes of clearing approved Nuclear deferral and variance account balances effective July 1, 2015. The final rider will be set using audited 2014 account balances. Based on current projected balances, a rider of $15.78/MWh would result. The basis for the requested Nuclear payment rider is presented in Ex. H1-2-1 Table 2.

RATE AND CONSUMER IMPACT

1.0 PURPOSE

This evidence presents the impact of the proposed payment riders on OPG's overall average rates and on a residential electricity consumer consuming at the 800 kWh per month level.

2.0 RATE IMPACT

The combined change to the production-weighted average of OPG's Regulated Hydroelectric and Nuclear base payment amounts and riders sought in this Application is estimated at 11.5 per cent using the illustrative riders based on proposed clearance of projected 2014 account balances. Calculation of this rate impact is shown at Ex. I1-1-2 Table 1.

3.0 CONSUMER IMPACT

The residential consumer bill impact of the proposed payment riders is estimated at $3.08 per month, on a typical monthly bill of $132.57 assuming monthly consumption at 800 kWh, and that OPG's share of total consumer usage is 58.1 per cent after adjustment for total system loss factor.

Table 1
Annualized Residential Consumer Impact
Test Period January 1, 2015 to December 31, 2016

Line No.	Description	Amount
		(a)
1	**Typical Consumption[1] (kWh/Month)**	842
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 11)	489
3	**Typical Bill[1] ($/Month)**	132.57
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)	**3.08**
5	**Typical Bill Impact (%)** (line 4 / line 3)	**2.3%**
6	EB-2013-0321 Payment Amounts Order OPG weighted average rate for 2015[2] ($/MWh)	54.75
7	Blended OPG 2015-16 weighted average rate with proposed riders[3] ($/MWh)	61.06
8	Change in OPG weighted average rate ($/MWh) (line 7 - line 6)	6.31
9	Approved 2014-15 OPG Regulated Production[4] (TWh)	161.6
10	Forecast of Provincial Demand[5] (TWh)	278.3
11	OPG Proportion of Consumer Usage (line 9 / line 10)	58.1%

Notes:

1 Typical monthly consumption (800 kWh) and typical monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at:
http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility
Typical Consumption includes line losses.

2 From Ex. I1-1-2 Table 2, line 11, col. (a).

3 From Ex. I1-1-2 Table 2, line 11, col. (b).

4 From Ex. I1-1-2 Table 2, line 7.

5 Based on forecast demand for 2014 (139.5 TWh) and 2015 (138.8 TWh) from Table 3.1 of IESO 18-Month Outlook Update for September 2014 to February 2016, published September 4, 2014.

Table 2
Computation of Percent Change in Payment Amounts
EB-2013-0321 to EB-2014-0370

Line No.	Description	Note	Nov-Dec 2014 per EB-2013-0321 Payment Amounts Order	Weighted Average 2015-16 per EB-2013-0321 Payment Amounts Order plus EB-2014-0370	((b)/(a))-1 Percent Change In Payment Amounts
			(a)	(b)	(c)
1	**Previously Regulated Hydroelectric Rate Including Rider ($/MWh)**	1	42.22	46.00	9%
2	**Newly Regulated Hydroelectric Rate including Rider ($/MWh)**	2	41.93	44.66	7%
3	**Nuclear Rate Including Rider ($/MWh)**	3	63.47	71.79	13%
4	**Approved 2014-15 Previously Regulated Hydroelectric Production (TWh)**	4	41.1	41.1	
5	**Approved 2014-15 Newly Regulated Hydroelectric Production (TWh)**	4	24.8	24.8	
6	**Approved 2014-15 Nuclear Production (TWh)**	4	95.6	95.6	
7	**Total Approved 2014-15 Production (TWh)** (line 4 + line 5 + line 6)		161.6	161.6	
8	**Previously Regulated Hydroelectric Portion of Production-Weighted Average Rate ($/MWh)** (line 1 x line 4 / line 7)		10.74	11.71	
9	**Newly Regulated Hydroelectric Portion of Production-Weighted Average Rate ($/MWh)** (line 2 x line 5 / line 7)		6.45	6.87	
10	**Nuclear Portion of Production-Weighted Average Rate ($/MWh)** (line 3 x line 6 / line 7)		37.56	42.48	
11	**Total Production-Weighted Average Rate ($/MWh)** (line 8 + line 9 + line 10)		54.75	61.06	
12	**OVERALL CHANGE IN PAYMENT AMOUNTS FROM EB-2013-0321 TO EB-2014-0370**				**11.5%**
	((line 11 col. (b) / line 11 col. (a)) -1)				

Notes:

1 Col. (a) is payment amount from EB-2013-0321 Payment Amounts Order, App. B, Table 1, line 3 ($40.20/MWh) plus EB-2012-0002 Approved Hydroelectric Rider 2014-A from EB-2012-0002 Payment Amounts Order, App. A, Table 1, line 13, col. (h) ($2.02/MWh)
Col. (b) is production-weighted average of approved and proposed rates and riders for 2015 - 2016.

2 Col. (a) is payment amount from EB-2013-0321 Payment Amounts Order, App. B, Table 1, line 3 ($41.93/MWh).
Col. (b) is production-weighted average of approved and proposed rates and riders for 2015 - 2016.

3 Col. (a) is payment amount from EB-2013-0321 Payment Amounts Order, App. D, Table 1, line 3 ($59.29/MWh) plus EB-2012-0002 Approved Nuclear Rider 2014-A from EB-2012-0002 Payment Amounts Order, App. A, Table 2, line 13, col. (h) ($4.18/MWh)
Col. (b) is production-weighted average of approved and proposed rates and riders for 2015 - 2016.

4 Previously regulated hydroelectric from EB-2013-0321 Payment Amounts Order, App. B, Table 1, line 2.
Newly regulated hydroelectric from EB-2013-0321 Ex. E1-1-1, Table 1, line 8, col. (e) plus col. (f).
Nuclear from EB-2013-0321 Payment Amounts Order, App. D, Table 1, line 2.
Forecast production is held constant in cols. (a), (b), (c), (d) and (e) at values approved in order to isolate the effect of the overall change in payment amounts.

IESO SETTLEMENT PROCESS

1. PURPOSE

This evidence provides a description of the settlement process with the IESO, particularly a description of the timelines associated with the requested effective date.

2. DESCRIPTION OF SETTLEMENT PROCESS

The general IESO settlement process is described in Chapter Nine of the Ontario Market Rules. OPG understands that in order for revised riders to be implemented on the first of a given month, a final rate order establishing the new payment amounts and riders would have to be issued by the 20th of the second month prior to the implementation month in order for the IESO to update their systems and perform the settlement without retroactive adjustment. For example, for implementation on July 1, the rate order would have to be issued on May 20.

Retroactive adjustment may be used for the months prior to the implementation date back to the effective date of new payment amounts and riders. For example, assuming a rate order on June 20, retroactive adjustment would be used for the month of July, with unadjusted implementation for the month of August and beyond.

The timelines for implementation are based on the changes proposed in this submission. Material changes to the proposed rate structure may require a longer lead time for implementation.