Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2010-0008

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain of its generating facilities.

BEFORE: Cynthia Chaplin
Presiding Member & Vice Chair

Marika Hare
Member

Cathy Spoel
Member

PAYMENT AMOUNTS ORDER

Ontario Power Generation Inc. ("OPG") filed an application with the Ontario Energy Board (the "Board") on May 26, 2010. The application was filed under section 78.1 of the *Ontario Energy Board Act, 1998*, S.O 1998, c. 15 (Schedule B) (the "Act"), seeking approval for payment amounts for OPG's prescribed generating facilities for the test period January 1, 2011 through December 31, 2012, to be effective March 1, 2011. Section 2 of Ontario Regulation 53/05, *Payments Under Section 78.1 of the Act,* ("O. Reg. 53/05"), sets out the prescribed, or regulated, hydroelectric and nuclear facilities. The Board assigned the application file number EB-2010-0008.

OPG also requested that the Board issue an order declaring the current payment amounts interim if the new payment amounts were not implemented by March 1, 2011. By order dated February 17, 2011, the Board declared the current payment amounts interim effective March 1, 2011.

The Board issued a Decision with Reasons ("Decision") on March 10, 2011. In the Decision, the Board directed OPG to file "…a draft payment amounts order which will include the final revenue requirement and payment amounts for the regulated hydroelectric and nuclear facilities, and reflect the findings made by the Board in this Decision. OPG should also include supporting schedules and a clear explanation of all calculations and assumptions used in deriving the payment amounts and the payment riders."

The Board also directed that the new payment amounts be made effective March 1, 2011. The Board noted its understanding that the Independent Electricity System Operator ("IESO") could implement this effective date through its billing processes without the necessity for a shortfall payment amounts rider to cover the period between March 1, 2011, and the date of the final payment amounts order.

On March 21, 2011, OPG filed a draft Payment Amounts Order ("draft order"). In correspondence accompanying the draft order, OPG confirmed that the IESO will implement payment amounts, "no later than five business days after receipt of the final [Board] order. The IESO will ensure retroactive recovery for the period March 1 up to the implementation date."

Board staff submitted that the impact assessment analysis should include the percent change in payment amounts from the current payment amounts, for reference. The Canadian Manufacturers & Exporters ("CME") agreed with this submission. OPG disagreed with the proposal noting that the percent change was not part of the filing requirements and that no electricity consumer directly pays the payment amounts. OPG provided the analysis, in the event the Board found that the analysis should be included.

Board staff submitted that the descriptions for certain deferral and variance accounts should be revised for clarity or to be consistent with the definitions approved by the previous payment amounts order. Board staff submitted that approved forecast amounts should be included in the description of the Ancillary Services Net Revenue

Variance Accounts and the Income and Other Taxes Variance Account, to be consistent with the previous payment amounts order and for reference. In reply, OPG submitted that the required reference figures can be found in tables in the draft order. Including them in the descriptions of the accounts is redundant and unnecessary and provides no additional clarity.

OPG replied that Board staff's proposal to remove the reference to capital tax from the description of the Income and Other Taxes Variance Account was not appropriate as capital taxes was listed in the definition in pre-filed evidence and the decision approved continuation of the account as proposed by OPG. Board staff also submitted that the payment amounts order should include a description of the purpose of the Tax Loss Variance Account for clarity. OPG replied that the additional wording is not necessary.

Staff also submitted that the description of interest on the balances of accounts should be revised. OPG accepted the staff proposal for the description of interest, and accepted that including reference to section 6(2)4 of O. Reg. 53/05 in the description of the Capacity Refurbishment Variance Account provided clarity.

OPG observed an error in the draft order, noting that the Tax Loss Variance Account should be listed with paragraph 10 (which identified accounts which are continued only for entries of amortization and interest), rather than paragraph 9.

Board Findings

The Board agrees with staff and CME that the impact assessment should include the percent change in payment amounts from the current payment amounts as a reference and as a measure of the overall impact of the Decision.

The Board finds that it is appropriate to include the approved forecast amounts in the description of the Ancillary Services Net Revenue Variance Accounts and the Income and Other Taxes Variance Account, as these amounts are used as the basis for measuring variances and for making entries into these accounts.

The Board agrees with OPG that the reference to capital tax in the description of the Income and Other Taxes Variance Account should be retained. The Board also agrees with OPG that the additional description of the Tax Loss Variance Account proposed by Board staff is not required.

OPG has agreed with Board staff regarding the revisions to the descriptions of the Capacity Refurbishment Variance Account and Interest. The Board accepts these revisions.

Confidentiality

The final payment amounts order incorporates information in Appendix A for which OPG sought, and received approval for, confidential treatment. Persons who have signed the Declaration and Undertaking that is Appendix D of the Board's *Practice Direction on Confidential Filings*, have already been provided with a confidential version of Appendix A as part of the draft order. Accordingly, the Board finds there is no need to issue an unredacted version of the final payment amounts order.

THE BOARD THEREFORE ORDERS THAT:

1. The test period revenue requirement is $1,419.2 million for the regulated hydroelectric facilities and $5,251.5 million for the regulated nuclear facilities, as set out in Appendix A. The deferral and variance account balances approved for disposition in the period March 1, 2011 to December 31, 2012, are a credit of $(60.2) million for the regulated hydroelectric facilities and a debit of $403.2 million for the regulated nuclear facilities, as set out in Appendix A. These revenue requirements and account balances shall form the basis of the payment amounts and the authorized payment riders.

2. Effective March 1, 2011, and subject to sections 3 and 4, for the regulated hydroelectric facilities, the payment amount is $35.78/MWh, as set out in Appendix B.

3. Effective March 1, 2011, the hydroelectric payment amount, including the authorized hydroelectric payment rider, applies to the average hourly net energy production in megawatt hours from the regulated hydroelectric facilities in any given month (the "average hourly volume") for each hour of that month. Where the actual net energy production from the regulated hydroelectric facilities that is supplied into the IESO-administered energy market in a given hour is greater than the average hourly volume, the incremental net energy production supplied into the IESO-administered energy market will receive the market price, calculated on a five minute basis. Where the actual net energy production from

the regulated hydroelectric facilities that is supplied into the IESO-administered energy market in a given hour is less than the average hourly volume, OPG's revenues will be adjusted by the difference between the average hourly volume and the actual net energy production that is supplied into the IESO-administered energy market, multiplied by the market price, calculated on a five minute basis.

4. Effective March 1, 2011, for the regulated hydroelectric facilities, the regulated hydroelectric payment rider for the amortization of the approved deferral and variance account balances is $(1.65)/MWh as set out in Appendix D. This payment rider is effective until December 31, 2012.

5. Effective March 1, 2011, and subject to section 6, for the regulated nuclear facilities, the payment amount is $51.52/MWh, as set out in Appendix C.

6. Effective March 1, 2011, for the regulated nuclear facilities, the nuclear payment rider for the amortization of the approved deferral and variance account balances is $4.33/MWh as set out in Appendix E. This payment rider is effective until December 31, 2012.

7. The IESO shall make payments to OPG in accordance with this Order as of March 1, 2011.

8. OPG shall recover the December 31, 2010 approved balances in the following deferral and variance accounts in accordance with Appendix F, effective March 1, 2011:

   - Hydroelectric Water Conditions Variance Account
   - Ancillary Services Net Revenue Variance Account – Hydroelectric
   - Income and Other Taxes Variance Account
   - Tax Loss Variance Account
   - Hydroelectric Interim Period Shortfall (Rider D) Variance Account
   - Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
   - Pickering A Return To Service Deferral Account
   - Nuclear Liability Deferral Account
   - Nuclear Development Variance Account
   - Transmission Outages and Restrictions Variance Account

- Ancillary Services Net Revenue Variance Account – Nuclear
- Capacity Refurbishment Variance Account
- Nuclear Fuel Cost Variance Account
- Bruce Lease Net Revenues Account
- Nuclear Interim Period Shortfall (Rider B) Variance Account
- Nuclear Deferral and Variance Over/Under Recovery Variance Account

9. OPG shall continue the following deferral and variance accounts in accordance with Appendix F, effective March 1, 2011:

   - Hydroelectric Water Conditions Variance Account
   - Ancillary Services Net Revenue Variance Account – Hydroelectric
   - Income and Other Taxes Variance Account
   - Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
   - Nuclear Liability Deferral Account
   - Nuclear Development Variance Account
   - Ancillary Services Net Revenue Variance Account – Nuclear
   - Capacity Refurbishment Variance Account
   - Bruce Lease Net Revenues Account
   - Nuclear Deferral and Variance Over/Under Recovery Variance Account

10. OPG shall continue the following deferral and variance accounts only for entries of amortization and interest in accordance with Appendix F, effective March 1, 2011:

    - Hydroelectric Interim Period Shortfall (Rider D) Variance Account
    - Pickering A Return To Service Deferral Account
    - Transmission Outages and Restrictions Variance Account
    - Nuclear Fuel Cost Variance Account
    - Nuclear Interim Period Shortfall (Rider B) Variance Account
    - Tax Loss Variance Account

11. OPG shall establish the following variance and deferral accounts in accordance with Appendix F, effective March 1, 2011:

    - Hydroelectric Surplus Baseload Generation Variance Account

– Hydroelectric Incentive Mechanism Variance Account

DATED at Toronto, April 11, 2011

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX A

TO

PAYMENT AMOUNTS ORDER

ONTARIO POWER GENERATION INC.

EB-2010-0008

EB-2010-0008 PAYMENT AMOUNTS ORDER - APPENDICES

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Numbers may not add due to rounding.

Table 1
Summary of Regulated Hydroelectric Revenue Requirement and Variance and Deferral Account Amortization Amounts ($M)

Line No.	Description	Note	2011 OPG Proposed	2011 Board Adjustment	2011 Board Approved	2012 OPG Proposed	2012 Board Adjustment	2012 Board Approved	Total OPG Proposed	Total Board Adjustment	Total Board Approved
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
			Note 1			Note 1			Note 1		
	Rate Base										
1	**Net Fixed Assets**		3,781.3	0.0	3,781.3	3,765.3	0.0	3,765.3	N/A	N/A	N/A
2	**Working Capital**		0.6	0.0	0.6	0.6	0.0	0.6	N/A	N/A	N/A
3	**Cash Working Capital**		21.5	0.0	21.5	21.5	0.0	21.5	N/A	N/A	N/A
4	**Total Rate Base**		3,803.4	0.0	3,803.4	3,787.4	0.0	3,787.4	N/A	N/A	N/A
	Capitalization										
5	**Short-term Debt**	2	114.0	2.3	116.3	111.3	5.5	116.8	N/A	N/A	N/A
6	**Long-Term Debt**	2	1,901.8	(2.3)	1,899.5	1,896.0	(5.6)	1,890.5	N/A	N/A	N/A
7	**Common Equity**	2	1,787.6	(0.0)	1,787.6	1,780.1	0.0	1,780.1	N/A	N/A	N/A
8	**Adjustment for Lesser of UNL or ARC**	2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
9	**Total Capital**		3,803.4	(0.0)	3,803.4	3,787.4	(0.0)	3,787.4	N/A	N/A	N/A
	Cost of Capital										
10	**Short-term Debt**	3	4.6	0.1	4.7	6.1	0.3	6.4	10.7	0.4	11.1
11	**Long-Term Debt**	3	106.9	(1.9)	105.0	105.8	(1.9)	104.0	212.7	(3.8)	208.9
12	**Return on Equity**	3	176.1	(7.5)	168.6	175.3	(5.3)	170.0	351.4	(12.8)	338.6
13	**Adjustment for Lesser of UNL or ARC**	3	N/A	0.0	N/A	N/A	0.0	N/A	N/A	0.0	N/A
14	**Total Cost of Capital**		287.6	(9.3)	278.2	287.3	(6.9)	280.4	574.9	(16.3)	558.6
	Expenses										
15	**OM&A**		128.2	0.0	128.2	125.9	0.0	125.9	254.1	0.0	254.1
16	**Fuel and GRC**	4	257.1	6.6	263.7	252.2	11.5	263.7	509.3	18.1	527.4
17	**Depreciation & Amortization**		65.6	0.0	65.6	65.0	0.0	65.0	130.6	0.0	130.6
18	**Property Taxes**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	**Total Expenses**		450.9	6.6	457.5	443.1	11.5	454.6	894.0	18.1	912.1
	Less:										
	Other Revenues										
20	**Bruce Lease Revenues Net of Direct Costs**		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	**Ancillary and Other Revenue**	5	44.9	[redacted]	[redacted]	46.2	[redacted]	[redacted]	91.1	[redacted]	[redacted]
22	**Total Other Revenues**		44.9	[redacted]	[redacted]	46.2	[redacted]	[redacted]	91.1	[redacted]	[redacted]
23	**Income Tax**	6	26.9	[redacted]	[redacted]	24.4	[redacted]	[redacted]	51.4	[redacted]	[redacted]
24	**Revenue Requirement**	7	720.5	(8.5)	711.9	708.7	(1.4)	707.2	1,429.2	(10.0)	1,419.2
25	**Amortization of Variance & Deferral Account Amounts**	8	(27.3)	0.0	(27.3)	(32.8)	0.0	(32.8)	(60.2)	0.0	(60.2)
26	**Revenue Requirement Plus Variance & Deferral Account Amortization Amounts**	7	693.1	(8.5)	684.6	675.9	(1.4)	674.4	1,369.0	(10.0)	1,359.0

For notes see Table 1a.

Numbers may not add due to rounding.

Table 1a
Notes to Table 1
Summary of Regulated Hydroelectric Revenue Requirement and Variance and Deferral Account Amortization Amounts

Notes:

1 Agrees to Ex. I1-T1-S1 Table 1 - Summary of Revenue Requirement for 2011 and 2012 as filed in EB-2010-0008, with the exception of Income Tax at line 23 (see Note 6) and Amortization of Variance & Deferral Account Amounts at line 25 (see Note 8).

2 Capitalization for OPG's combined regulated operations for January 1 to December 31, 2011 is provided in Payment Amounts Order, Appendix A, Table 4a (OPG Proposed) and Table 4b (Board Approved), and for January 1 to December 31, 2012 is provided in Payment Amounts Order, Appendix A, Table 5a (OPG Proposed) and Table 5b (Board Approved). Capital structure amounts are allocated to regulated hydroelectric and nuclear based on their relative rate base amounts as presented below.
OPG has directly assigned the portion of rate base financed at the weighted average accretion rate to its nuclear operations.
The allocation of the remaining capital structure components has been revised to reflect the change in the nuclear rate base.

Table to Note 2 - Allocation of Capital Structure Amounts to Regulated Hydroelectric and Nuclear

Line No.	Item	Reference	2011	2012
			(a)	(b)
1	Approved reg. hydroelectric rate base ($M)	Payment Amounts Order, Appendix A, Table 1, cols. (c) and (f), line 4	3,803.4	3,787.4
2	Approved nuclear rate base ($M)	Payment Amounts Order, Appendix A, Table 2, cols. (c) and (f), line 4	3,915.8	3,844.9
3	Financing directly assigned to nuclear rate base ($M)	Payment Amounts Order, Appendix A, Table 2, cols. (c) and (f), line 8	1,523.3	1,490.1
4	Nuclear rate base financed by capital structure ($M) (line 2 - line 3)		2,392.5	2,354.8
5	Reg. hydroelectric allocation (line 1 / (line 1+line 4))		61.39%	61.66%
6	Nuclear allocation (line 4 / (line 1+line 4))		38.61%	38.34%

3 Cost of capital for OPG's combined regulated operations is provided in Payment Amounts Order, Appendix A, Tables 4a (2011 OPG Proposed), 4b (2011 Board Approved), 5a (2012 OPG Proposed) and 5b (2012 Board Approved).
The cost of capital is allocated between regulated hydroelectric and nuclear operations consistent with the capital structure allocation described in Note 2 above.

4 Gross Revenue Charge increased by $6.6M in 2011 and $11.5M in 2012 to reflect the increase in the regulated hydroelectric production forecast per EB-2010-0008 Decision With Reasons, p. 24.

5 [redacted]

6 Board Approved regulatory income tax expense for combined regulated operations is provided in Payment Amounts Order, Appendix A, Table 6 (for 2011) and Table 7 (for 2012), at line 27. The expense is allocated between the regulated hydroelectric and nuclear businesses on the basis of each business' taxable income, as described in EB-2010-0008, Ex. F4-T2-S1.

7 Amounts on lines 24 and 26 for "OPG Proposed" differ from amounts filed in EB-2010-0008 due to changes in amounts for Income Tax (line 23) and Amortization of Variance & Deferral Account Amounts (line 25) as discussed in notes 6 and 8.

8 Amortization of Variance & Deferral Account Amounts in "OPG Proposed" and "Board Approved" columns are based on actual variance and deferral account balances as at Dec. 31, 2010. See Payment Amounts Order, Appendix D, Table 1, cols. (e) and (f), line 7.

Numbers may not add due to rounding.

Table 2

Summary of Nuclear Revenue Requirement and Variance and Deferral Account Amortization Amounts ($M)

Line No.	Description	Note	2011 OPG Proposed	2011 Board Adjustment	2011 Board Approved	2012 OPG Proposed	2012 Board Adjustment	2012 Board Approved	Total OPG Proposed	Total Board Adjustment	Total Board Approved
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
			Note 1			Note 1			Note 1		
	Rate Base										
1	**Net Fixed Assets**	2	3,172.2	(125.5)	3,046.7	3,302.3	(306.0)	2,996.3	N/A	N/A	N/A
2	**Working Capital**		865.1	0.0	865.1	844.5	0.0	844.5	N/A	N/A	N/A
3	**Cash Working Capital**		4.0	0.0	4.0	4.0	0.0	4.0	N/A	N/A	N/A
4	**Total Rate Base**		4,041.3	(125.5)	3,915.8	4,150.8	(306.0)	3,844.9	N/A	N/A	N/A
	Capitalization										
5	**Short-term Debt**	3	75.5	(2.3)	73.2	78.2	(5.5)	72.6	N/A	N/A	N/A
6	**Long-Term Debt**	3	1,259.0	(64.2)	1,194.9	1,332.0	(156.6)	1,175.4	N/A	N/A	N/A
7	**Common Equity**	3	1,183.5	(59.0)	1,124.5	1,250.5	(143.8)	1,106.7	N/A	N/A	N/A
8	**Adjustment for Lesser of UNL or ARC**	3	1,523.3	0.0	1,523.3	1,490.1	0.0	1,490.1	N/A	N/A	N/A
9	**Total Capital**	2	4,041.3	(125.5)	3,915.8	4,150.8	(306.0)	3,844.8	N/A	N/A	N/A
	Cost of Capital										
10	**Short-term Debt**	4	3.0	(0.1)	2.9	4.3	(0.3)	4.0	7.3	(0.4)	6.9
11	**Long-Term Debt**	4	70.8	(4.7)	66.0	74.4	(9.7)	64.6	145.1	(14.5)	130.7
12	**Return on Equity**	4	116.6	(10.5)	106.0	123.2	(17.5)	105.7	239.7	(28.0)	211.7
13	**Adjustment for Lesser of UNL or ARC**	4	85.0	0.0	85.0	83.1	0.0	83.1	168.1	0.0	168.1
14	**Total Cost of Capital**		275.4	(15.4)	260.0	284.9	(27.5)	257.4	560.3	(42.9)	517.4
	Expenses										
15	**OM&A**	5	2,021.2	(55.7)	1,965.5	2,067.9	(91.6)	1,976.3	4,089.1	(147.3)	3,941.9
16	**Fuel and GRC**	6	235.6	4.5	240.1	261.7	4.5	266.2	497.4	9.0	506.4
17	**Depreciation & Amortization**		235.4	0.0	235.4	256.4	0.0	256.4	491.8	0.0	491.8
18	**Property Taxes**		16.0	0.0	16.0	16.6	0.0	16.6	32.6	0.0	32.6
19	**Total Expenses**		2,508.3	(51.2)	2,457.1	2,602.6	(87.1)	2,515.6	5,110.9	(138.3)	4,972.7
	Less:										
	Other Revenues										
20	**Bruce Lease Revenues Net of Direct Costs**		128.1	0.0	128.1	143.0	0.0	143.0	271.1	0.0	271.1
21	**Ancillary and Other Revenue**	7	32.0	[redacted]	[redacted]	24.0	[redacted]	[redacted]	56.0	[redacted]	[redacted]
22	**Total Other Revenues**		160.1	[redacted]	[redacted]	167.0	[redacted]	[redacted]	327.1	[redacted]	[redacted]
23	**Income Tax**	8	47.5	[redacted]	[redacted]	67.8	[redacted]	[redacted]	115.2	[redacted]	[redacted]
24	**Revenue Requirement**	9	2,671.1	(85.1)	2,586.0	2,788.3	(122.8)	2,665.5	5,459.4	(207.9)	5,251.5
25	**Amortization of Variance & Deferral Account Amounts**	10	201.4	0.0	201.4	201.8	0.0	201.8	403.2	0.0	403.2
26	**Revenue Requirement Plus Variance & Deferral Account Amortization Amounts**	9	2,872.5	(85.1)	2,787.4	2,990.2	(122.8)	2,867.3	5,862.6	(207.9)	5,654.7

For notes see Table 2a.

Numbers may not add due to rounding.

Table 2a
Notes to Table 2
Summary of Nuclear Revenue Requirement and Variance and Deferral Account Amortization Amounts

Notes:

1 Agrees to Ex. I1-T1-S1 Table 1 - Summary of Revenue Requirement for 2011 and 2012 as filed in EB-2010-0008, with the exception of Income Tax at line 23 (see Note 8) and Amortization of Variance & Deferral Account Amounts at line 25 (see Note 10).

2 Adjustment to remove Darlington CWIP from Nuclear rate base per EB-2010-0008 Decision with Reasons, p. 79: $125.5M in 2011 (Ex. B3-T1-S1, Table 1, col. (c), line 14) and $306.0M in 2012 (Ex. B3-T1-S1, Table 1, col. (f), line 14).

3 Capitalization for OPG's combined regulated operations for January 1 to December 31, 2011 is provided in Payment Amounts Order, Appendix A, Table 4a (OPG Proposed) and Table 4b (Board Approved), and for January 1 to December 31, 2012 is provided in Payment Amounts Order, Appendix A, Table 5a (OPG Proposed) and Table 5b (Board Approved).

Capital structure amounts are allocated between regulated hydroelectric and nuclear consistent with the capital structure allocation described in Payment Amounts Order, Appendix A, Table 1a, Note 2. The resulting allocation ratios for nuclear operations are:
Nuclear allocation for 2011: 38.61%
Nuclear allocation for 2012: 38.34%

4 Cost of capital for OPG's combined regulated operations is provided in Payment Amounts Order, Appendix A, Tables 4a (2011 OPG Proposed), 4b (2011 Board Approved), 5a (2012 OPG Proposed) and 5b (2012 Board Approved).
The cost of capital is allocated between regulated hydroelectric and nuclear consistent with the capital structure allocation described in Payment Amounts Order, Appendix A, Table 1a, Note 2.

5 Combined impact on nuclear OM&A of Board adjustments to increase CNSC costs, reduce compensation costs, reduce nuclear insurance costs and correct the Fuel Channel Lifecycle Management (FCLM) cost double count is as follows:

Table to Note 5 - Nuclear OM&A Adjustments

Line No.	Item	Reference	Board Adjustments ($M)		
			2011	2012	Total
			(a)	(b)	(c)
1	Increase CNSC costs	EB-2010-0008 Decision p. 49 / Ex. N-T1-S1, p. 1	6.5	6.5	13.0
2	Reduce compensation costs	EB-2010-0008 Decision pp. 86, 87	(55.0)	(90.0)	(145.0)
3	Reduce nuclear insurance costs	EB-2010-0008 Decision p. 96	(2.5)	(4.4)	(6.9)
4	Remove FCLM cost double count	EB-2010-0008 Decision p. 50 / OPG's EB-2010-0008 Argument-in-Chief, p. 98	(4.9)	(3.9)	(8.8)
5	Add 50% share of other support costs related to heavy water sales*	EB-2010-0008 Ex. G2-T1-S1, Section 4.1	0.2	0.2	0.4
6	Total		(55.7)	(91.6)	(147.3)

* Adjustment to increase nuclear base OM&A for Commercial Services presented in EB-2010-0008, Ex. F2-T2-S1, Tables 4 and 5, line 24.

6 Fuel cost increased by $9.0M over test period to reflect the increase in the nuclear production forecast per EB-2010-0008 Decision With Reasons, p. 55.

7 Per EB-2010-0008 Decision, p. 64, the adjustments reflect the 50/50 sharing of [redacted] in 2011 and [redacted] in 2012 of forecast heavy water sales, net of direct costs. The effect of 50/50 sharing of forecast heavy water sales is calculated as follows:

Table to Note 7 - Forecast Heavy Water Sales Adjustments

Line No.	Item	Reference	Board Adjustments ($M)		
			2011	2012	Total
			(a)	(b)	(c)
1	Forecast heavy water sales revenue	EB-2010-0008 Decision p. 64 / EB-2010-0008 Ex. J5.5	[redacted]	[redacted]	[redacted]
2	Forecast of direct costs	EB-2010-0008 Decision p. 64 / EB-2010-0008 Ex. L14.27	(0.8)	(1.0)	(1.8)
3	Revenues net of direct costs		[redacted]	[redacted]	[redacted]
4	50% of revenues net of direct costs				

8 Board Approved regulatory income tax expense for combined regulated operations is provided in Payment Amounts Order, Appendix A, Table 6 (for 2011) and Table 7 (for 2012), at line 27. The expense is allocated between the regulated hydroelectric and nuclear businesses on the basis of each business' taxable income, as described in EB-2010-0008, Ex. F4-T2-S1.

9 Amounts on lines 24 and 26 for "OPG Proposed" differ from amounts filed in EB-2010-0008 due to changes in amounts for Income Tax (line 23) and Amortization of Variance & Deferral Account Amounts (line 25) as discussed in notes 8 and 10.

10 Amortization of Variance & Deferral Account Amounts in "OPG Proposed" and "Board Approved" columns are based on actual variance and deferral account balances as at Dec. 31, 2010. See Payment Amounts Order, Appendix E, Table 1, cols. (e) and (f), line 13.

Numbers may not add due to rounding.

Table 3
Summary of Approved Revenue Requirement Deficiency/Sufficiency by Technology ($M)
Test Period January 1, 2011 to December 31, 2012

Line No.	Description	Regulated Hydroelectric 2011	Regulated Hydroelectric 2012	Regulated Hydroelectric Total	Nuclear 2011	Nuclear 2012	Nuclear Total	Total Test Period
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Forecast Production (TWh)**[1]	19.8	19.8	39.7	50.4	51.5	101.9	N/A
2	**Prescribed Payment Amount ($/MWh)**[2]	36.66	36.66	36.66	52.98	52.98	52.98	N/A
3	**Indicated Production Revenue ($M)**	727.0	727.0	1,454.1	2,671.4	2,728.4	5,399.8	6,853.8
	(line 1 x line 2)							
4	**Approved Revenue Requirement ($M)**[3]	711.9	707.2	1,419.2	2,586.0	2,665.5	5,251.5	6,670.7
5	**Revenue Requirement Deficiency (Sufficiency) ($M)**	(15.1)	(19.8)	(34.9)	(85.4)	(62.9)	(148.3)	(183.2)
	(line 4 - line 3)							
6	**Revenue Requirement Deficiency (Sufficiency) Approved for Recovery ($M)**[4]	(12.7)	(19.8)	(32.5)	(70.6)	(62.9)	(133.5)	(166.0)

Notes:

1 Forecast production adjusted to remove the allowance for surplus baseload generation (SBG) from the regulated hydroelectric forecast and reduce the allowance for major unforeseen events in nuclear forecast, per EB-2010-0008 Decision with Reasons, pp. 22 and 39.

Table to Note 1 - Forecast Production Adjustments

Line No.	Item	Regulated Hydroelectric (TWh) 2011	Regulated Hydroelectric (TWh) 2012	Regulated Hydroelectric (TWh) Total	Nuclear (TWh) 2011	Nuclear (TWh) 2012	Nuclear (TWh) Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	Forecast Production from EB-2010-0008, Ex. I1-T1-S1, Table 4	19.4	19.0	38.4	48.9	50.0	98.9
2	Board Adjustments - EB-2010-0008 Decision With Reasons, pp. 22 and 39	0.5	0.8	1.3	1.5	1.5	3.0
3	Board Approved Test Period Forecast Production	19.8	19.8	39.7	50.4	51.5	101.9

2 From EB-2007-0905 Payment Amounts Order, Appendix B, Table 1 (regulated hydroelectric) and Appendix C Table 1 (nuclear).

3 From Payment Amounts Order, Appendix A, Table 1 (regulated hydroelectric) and Appendix A, Table 2 (nuclear).

4 Value for 2011 is line 5 x (March to December forecast production / line 1). March to December 2011 forecast production is from Payment Amounts Order, Appendix D, Table 1, line 8 (regulated hydro) and Appendix E, Table 1, line 14 (nuclear). Value for 2012 is the amount on line 5.

Numbers may not add due to rounding.

Table 4a

Summary of Proposed Capitalization and Cost of Capital: January 1, 2011 to December 31, 2011 ($M)[1]

Line No.	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
		(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:				
1	**Short-term Debt**	189.5	3.0%	2.64%	7.6
2	**Existing/Planned Long-Term Debt**	2,283.1	36.1%	5.53%	126.2
3	**Other Long-Term Debt Provision**	877.7	13.9%	5.87%	51.5
4	**Total Debt**	3,350.3	53.0%	5.53%	185.3
5	**Common Equity**	2,971.1	47.0%	9.85%	292.7
6	**Rate Base Financed by Capital Structure**	6,321.4	80.6%	7.56%	477.9
7	**Adjustment for Lesser of UNL or ARC**	1,523.3	19.4%	5.58%	85.0
8	**Rate Base**	7,844.7	100%	7.18%	562.9

Notes:
1 Amounts in table as per EB-2010-0008, Ex. C1-T1-S1, Table 2.

Numbers may not add due to rounding.

Table 4b
Summary of Board Approved Capitalization and Cost of Capital: January 1, 2011 to December 31, 2011 ($M)

Line No.	Note	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
		Capitalization and Return on Capital:				
1	1	**Short-term Debt**	189.5	3.1%	2.64%	7.6
2	1	**Existing/Planned Long-Term Debt**	2,283.1	36.9%	5.53%	126.2
3	2	**Other Long-Term Debt Provision**	811.2	13.1%	5.53%	44.9
4	3	**Total Debt**	3,283.8	53.0%	5.44%	178.6
5	3	**Common Equity**	2,912.1	47.0%	9.43%	274.6
6		**Rate Base Financed by Capital Structure**	6,195.9	80.3%	7.31%	453.2
7	4	**Adjustment for Lesser of UNL or ARC**	1,523.3	19.7%	5.58%	85.0
8	5	**Approved Rate Base**	7,719.2	100.0%	6.97%	538.2

Notes:

1 Methodology to determine regulated portion of short-term and existing/planned long-term debt, the associated cost rates and the associated cost amounts were approved as proposed by OPG.

2 Debt required to balance capital structure with approved rate base. Interest rate of 5.53%, the rate for existing and planned long term debt at col. (c), line 2, is used as directed by the Board in EB-2010-0008 Decision With Reasons, p. 125.

3 The Board approved a Debt / Equity ratio of 53% debt, 47% equity (EB-2010-0008 Decision With Reasons, p. 116) and a 9.43% return on common equity (EB-2010-0008 Decision With Reasons, p. 122).

4 The Board accepted OPG's proposed Adjustment for Lesser of UNL or ARC. Adjustment for Lesser of UNL or ARC calculation is referenced at EB-2010-0008, Ex. C2-T1-S2, Table 1, line 29.

5 The Board approved rate base reflects the adjustment to remove Darlington CWIP of $125.5M as discussed in Payment Amounts Order, Appendix A, Table 2a, Note 2.

Numbers may not add due to rounding.

Table 5a

Summary of Proposed Capitalization and Cost of Capital: January 1, 2012 to December 31, 2012 ($M)[1]

Line No.	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
		(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:				
1	**Short-term Debt**	189.5	2.9%	4.13%	10.4
2	**Existing/Planned Long-Term Debt**	2,502.8	38.8%	5.50%	137.6
3	**Other Long-Term Debt Provision**	725.2	11.2%	5.87%	42.6
4	**Total Debt**	3,417.5	53.0%	5.58%	190.6
5	**Common Equity**	3,030.6	47.0%	9.85%	298.5
6	**Rate Base Financed by Capital Structure**	6,448.1	81.2%	7.59%	489.1
7	**Adjustment for Lesser of UNL or ARC**	1,490.1	18.8%	5.58%	83.1
8	**Rate Base**	7,938.2	100.0%	7.21%	572.2

Notes:

1 Amounts in table as per EB-2010-0008, Ex. C1-T1-S1, Table 1.

Table 5b
Summary of Board Approved Capitalization and Cost of Capital: January 1, 2012 to December 31, 2012 ($M)

Line No.	Note	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
		Capitalization and Return on Capital:				
1	1	**Short-term Debt**	189.5	3.1%	4.13%	10.4
2	1	**Existing/Planned Long-Term Debt**	2,502.8	40.8%	5.50%	137.6
3	2	**Other Long-Term Debt Provision**	563.0	9.2%	5.50%	31.0
4	3	**Total Debt**	3,255.3	53.0%	5.50%	179.0
5	3	**Common Equity**	2,886.8	47.0%	9.55%	275.7
6		**Rate Base Financed by Capital Structure**	6,142.1	80.5%	7.40%	454.7
7	4	**Adjustment for Lesser of UNL or ARC**	1,490.1	19.5%	5.58%	83.1
8	5	**Approved Rate Base**	7,632.2	100.0%	7.05%	537.8

Notes:

1 Methodology to determine regulated portion of short-term and existing/planned long-term debt, the associated cost rates and the associated cost amounts were approved as proposed by OPG.

2 Debt required to balance capital structure with approved rate base. Interest rate of 5.50%, the rate for existing and planned long term debt at col (c), line 2, is used as directed by the Board in EB-2010-0008 Decision With Reasons, p. 125.

3 The Board approved a Debt / Equity ratio of 53% debt, 47% equity (EB-2010-0008 Decision With Reasons, p. 116) and a 9.55% return on common equity (EB-2010-0008 Decision With Reasons, p. 123).
Refer to Payment Amounts Order Appendix A, Table 5c for derivation of 9.55%.

4 The Board accepted OPG's proposed Adjustment for Lesser of UNL or ARC. Adjustment for Lesser of UNL or ARC calculation is referenced at EB-2010-0008, Ex. C2-T1-S2, Table 1, line 29.

5 The Board approved rate base reflects the adjustment to remove Darlington CWIP of $306.0M as discussed in Payment Amounts Order, Appendix A, Table 2a, Note 2.

Numbers may not add due to rounding.

Table 5c
Calculation of 2012 Return on Equity

Market Rates for the Month of: **November 2010**

Step 1: Analysis of Business Day Information in Month

	Government of Canada 10 yr	Government of Canada 30 yr	A - Rated Utilities 30 yr	30 yr Govt over 10 yr Govt	30 yr Utility over 30 yr Govt
01-Nov-10	2.8300	3.4700	4.9703	0.6400	1.5003
02-Nov-10	2.8800	3.4800	4.9160	0.6000	1.4360
03-Nov-10	2.8700	3.4900	4.9410	0.6200	1.4510
04-Nov-10	2.8100	3.4700	4.9161	0.6600	1.4461
05-Nov-10	2.8500	3.4900	4.9534	0.6400	1.4634
06-Nov-10					
07-Nov-10					
08-Nov-10	2.8900	3.5000	4.9359	0.6100	1.4359
09-Nov-10	2.9700	3.5700	4.9701	0.6000	1.4001
10-Nov-10	2.9800	3.5900	4.9390	0.6100	1.3490
11-Nov-10					
12-Nov-10	3.0200	3.6300	4.9708	0.6100	1.3408
13-Nov-10					
14-Nov-10					
15-Nov-10	3.1400	3.7100	5.0822	0.5700	1.3722
16-Nov-10	3.0700	3.6800	5.0204	0.6100	1.3404
17-Nov-10	3.1000	3.6700	5.0243	0.5700	1.3543
18-Nov-10	3.1200	3.6600	5.0419	0.5400	1.3819
19-Nov-10	3.1400	3.6200	5.0317	0.4800	1.4117
20-Nov-10					
21-Nov-10					
22-Nov-10	3.0800	3.5800	5.0010	0.5000	1.4210
23-Nov-10	3.1100	3.6000	5.0436	0.4900	1.4436
24-Nov-10	3.1900	3.6500	5.0476	0.4600	1.3976
25-Nov-10	3.1600	3.6300	5.0354	0.4700	1.4054
26-Nov-10	3.1100	3.5700	5.0193	0.4600	1.4493
27-Nov-10					
28-Nov-10					
29-Nov-10	3.0800	3.5200	4.9801	0.4400	1.4601
30-Nov-10	3.0700	3.4800	4.9516	0.4100	1.4716
	3.02	3.57	4.99	0.552	1.416
Source	Bank of Canada		Bloomberg L.P.		
Identifier	**v39055**	**v39056**	**C29530Y Index**		

Step 2: 10-Year Government of Canada Bond Yield Forecast

Source: Global Insight[1]	**Publication Date:**		**4-Nov-10**
	Full Year	Full Year	Average
November-2011	**3.29**	**3.29**	3.29%
	2012	2012	

Step 3: Long Canada Bond Forecast

10 Year Government of Canada Concensus Forecast (from Step 2)	3.29%
Actual Spread of 30-year over 10-year Government of Canada	0.55%
Long Canada Bond Forecast (LCBF)	3.84%

Step 4: Return on Equity (ROE) Forecast

Initial ROE			**9.75%**
Change in Long Canada Bond Yield Forecast from Base Year			
	LCBF (November 2010) (from Step 3)	3.84%	
	Base LCBF	**4.25%**	
	Spread	-0.41%	
	0.5		-0.204%
Change in A-rated Utility Bond Yield from Base Year			
	A-Rated Bond Yield Spread (November 2010) (from Step 1)	1.42%	
	Base A-Rated Utility Bond Yield	**1.42%**	
	Spread	0.00%	
	0.5		0.000%
Return on Equity based on November 2010 data			**9.55%**

Step 5: Deemed Long-term Debt Rate Forecast

Long Canada Bond Forecast for November 2010 (from Step 3)	3.84%
A-Rated Utility Bond Yield Spread November 2010 (from Step 1)	1.42%
Deemed Long-Term Debt Rate Based on November 2010 data	**5.26%**

Notes:
1 Global Insight data is available for the entire 2012 year. It was used as the 10-year Government of Canada Bond Yield forecast in Step 2 of the OEB's formula for determining ROE.

Numbers may not add due to rounding.

Table 6
Summary of Changes in Regulatory Income Taxes for Prescribed Facilities ($M)
Year Ending December 31, 2011

Line No.	Particulars	OPG Proposed	Board Adjustment	Board Approved
		(a)	(b)	(c)
		Note 1		
	Determination of Regulatory Taxable Income			
1	**Regulatory Earnings Before Tax**[2]	246.4	(51.1)	195.3
	Additions for Regulatory Tax Purposes:			
2	**Depreciation and Amortization**	298.4	0.0	298.4
3	**Nuclear Waste Management Expenses**	27.5	0.0	27.5
4	**Receipts from Nuclear Segregated Funds**	46.6	0.0	46.6
5	**Pension and OPEB/SPP Accrual**	287.1	0.0	287.1
6	**Regulatory Asset Amortization - Nuclear Liability Deferral Account**	17.8	0.0	17.8
7	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account**[3]	113.4	0.0	113.4
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**[4]	(12.8)	0.0	(12.8)
9	**Reversal of Amounts Recorded in Income and Other Taxes Variance Account**	0.0	0.0	0.0
10	**Adjustment Related to Financing Cost for Nuclear Liabilities**	85.0	0.0	85.0
11	**Taxable SR&ED Investment Tax Credits of Prior Periods**	8.7	0.0	8.7
12	**Other**	42.8	0.0	42.8
13	**Total Additions**	914.4	0.0	914.4
	Deductions for Regulatory Tax Purposes:			
14	**CCA**	298.9	0.0	298.9
15	**Cash Expenditures for Nuclear Waste & Decommissioning**	127.3	0.0	127.3
16	**Contributions to Nuclear Segregated Funds**	145.0	0.0	145.0
17	**Pension Plan Contributions**	206.1	0.0	206.1
18	**OPEB/SPP Payments**	75.6	0.0	75.6
19	**Regulatory Asset Deduction - Nuclear Liability Deferral Account**[5]	3.9	0.0	3.9
20	**SR&ED Qualifying Capital Expenditures**	8.0	0.0	8.0
21	**SR&ED Investment Tax Credits Recognized in Regulatory Earnings Before Tax**	8.8	0.0	8.8
22	**Other**[6]	3.1	0.0	3.1
23	**Total Deductions**	876.8	0.0	876.8
24	**Regulatory Taxable Income** (line 1 + line 13 - line 23)	284.0	(51.1)	233.0
25	**Regulatory Income Taxes - Federal** (line 24 x line 28)	46.9	(8.4)	38.4
26	**Regulatory Income Taxes - Provincial** (line 24 - line 11) x (line 29 + line 30)	27.5	(5.1)	22.4
27	**Total Regulatory Income Taxes**	74.4	(13.5)	60.9
	Income Tax Rate:			
28	**Federal Tax**	16.50%	N/A	16.50%
29	**Provincial Tax**	12.00%	N/A	12.00%
30	**Provincial Manufacturing & Processing Profits Deduction**	-2.00%	N/A	-2.00%
31	**Total Income Tax Rate**	26.50%	N/A	26.50%

For notes see Table 6a.

Numbers may not add due to rounding.

Table 6a
Notes to Table 6
Summary of Changes in Regulatory Income Taxes for Prescribed Facilities ($M)
Year Ending December 31, 2011

Notes:

1 "OPG Proposed" amounts agree to Ex. F4-T2-S1 Table 5, col. (b) as filed in EB-2010-0008, with the exception of lines 1, 7, 8, 19 and 22, which changed to reflect audited balances in variance and deferral accounts as at December 31, 2010. Specific changes are discussed in notes 2 through 6 below.

2 Regulatory Earnings Before Tax for 2011 are calculated as follows:

Table to Note 2 - Calculation of Regulatory EBT for 2011 ($M)

Line No.	Item	Reference	OPG Proposed	Board Adjustment	Board Approved
			(a)	(b)	(c)
1a	Requested After Tax Return on Equity	"OPG Proposed" per EB-2010-0008 Ex. F4-T2-S1 Table 5, Note 1, line 1. "Board Approved" per Payment Amounts Order, Appendix A, Table 4b, col (d), line 5.	292.7	(18.0)	274.6
2a	Less: Bruce Lease Net Revenues	EB-2010-0008 Ex. F4-T2-S1 Table 5, Note 1, line 2	128.1	0.0	128.1
3a	Add: Single Payment Amounts Adjustment	EB-2010-0008 Ex. F4-T2-S1 Table 5, Note 1, line 3	7.4	(19.5)	(12.1)
4a		line 1a - line 2a + line 3a	172.0	(37.5)	134.4
5a	Additions for Regulatory Tax Purposes	line 13 (where line 13 refers to EB-2010-0008 Payment Amounts Order, Appendix A, Table 6)	914.4	0.0	914.4
6a	Deductions for Regulatory Tax Purposes	line 23 (where line 23 refers to EB-2010-0008 Payment Amounts Order, Appendix A, Table 6)	876.8	0.0	876.8
7a		line 4a + line 5a - line 6a	209.6	(37.5)	172.1
8a	Regulatory Income Taxes - Federal	line 7a x line 28 / (1 - line 31) (where lines 28 and 31 refer to EB-2010-0008 Payment Amounts Order, Appendix A, Table 6)	47.1	(8.4)	38.6
9a	Regulatory Income Taxes - Provincial	(line 7a - line 11) x (line 29 + line 30) / (1- line 31) (where lines 11, 29, 30 and 31 refer to EB-2010-0008 Payment Amounts Order, Appendix A, Table 6)	27.3	(5.1)	22.2
10a	Total Regulatory Income Taxes	line 8a + line 9a	74.4	(13.5)	60.9
11a	Requested After Tax Return on Equity	line 1a	292.7	(18.0)	274.6
12a	Less: Bruce Lease Net Revenues	line 2a	128.1	0.0	128.1
13a	Add: Total Regulatory Income Taxes	line 10a	74.4	(13.5)	60.9
14a	Add: Single Payment Amounts Adjustment		7.4	(19.5)	(12.1)
15a	Regulatory Earnings Before Tax	line 11a - line 12a + line 13a + line 14a	246.4	(51.1)	195.3

3 "OPG Proposed" amount reflects the audited balance of the Bruce Lease Net Revenues Variance Account as at December 31, 2010. The amount is equal to the amortization of the account balance in 2011 as per Payment Amounts Order, Appendix E, Table 1, col. (e), line 8.

4 "OPG Proposed" amount reflects the amortization of the portion of the audited balance of the Income and Other Taxes Variance Account as at December 31, 2010 pertaining to variances that are not deductible for tax purposes.

5 "OPG Proposed" amount reflects the amortization of the tax deductible portion of the audited balance of the Nuclear Liability Deferral Account as at December 31, 2010.

6 "OPG Proposed" amount reflects the amortization of the interest improvement portion of the audited balance of the Bruce Lease Net Revenues Variance Account as at December 31, 2010.

Numbers may not add due to rounding.

Table 7
Summary of Changes in Regulatory Income Taxes for Prescribed Facilities ($M)
Year Ending December 31, 2012

Line No.	Particulars	OPG Proposed	Board Adjustment	Board Approved
		(a)	(b)	(c)
		Note 1		
	Determination of Regulatory Taxable Income			
1	**Regulatory Earnings Before Tax**[2]	240.3	(4.4)	235.9
	Additions for Regulatory Tax Purposes:			
2	**Depreciation and Amortization**	320.1	0.0	320.1
3	**Nuclear Waste Management Expenses**	29.3	0.0	29.3
4	**Receipts from Nuclear Segregated Funds**	58.0	0.0	58.0
5	**Pension and OPEB/SPP Accrual**	345.9	0.0	345.9
6	**Regulatory Asset Amortization - Nuclear Liability Deferral Account**	21.4	0.0	21.4
7	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account**[3]	136.0	0.0	136.0
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**[4]	(15.4)	0.0	(15.4)
9	**Reversal of Amounts Recorded in Income and Other Taxes Variance Account**	0.0	0.0	0.0
10	**Adjustment Related to Financing Cost for Nuclear Liabilities**	83.1	0.0	83.1
11	**Taxable SR&ED Investment Tax Credits of Prior Periods**	8.8	0.0	8.8
12	**Other**	39.0	0.0	39.0
13	**Total Additions**	1,026.2	0.0	1,026.2
	Deductions for Regulatory Tax Purposes:			
14	**CCA**	315.1	0.0	315.1
15	**Cash Expenditures for Nuclear Waste & Decommissioning**	126.6	0.0	126.6
16	**Contributions to Nuclear Segregated Funds**	140.4	0.0	140.4
17	**Pension Plan Contributions**	206.1	0.0	206.1
18	**OPEB/SPP Payments**	80.8	0.0	80.8
19	**Regulatory Asset Deduction - Nuclear Liability Deferral Account**[5]	4.6	0.0	4.6
20	**SR&ED Qualifying Capital Expenditures**	8.0	0.0	8.0
21	**SR&ED Investment Tax Credits Recognized in Regulatory Earnings Before Tax**	8.8	0.0	8.8
22	**Other**[6]	3.8	0.0	3.8
23	**Total Deductions**	894.1	0.0	894.1
24	**Regulatory Taxable Income** (line 1 + line 13 - line 23)	372.4	(4.4)	367.9
25	**Regulatory Income Taxes - Federal** (line 24 x line 28)	55.9	(0.7)	55.2
26	**Regulatory Income Taxes - Provincial** (line 24 - line 11) x (line 29 + line 30)	36.4	(0.4)	35.9
27	**Total Regulatory Income Taxes**	92.2	(1.1)	91.1
	Income Tax Rate:			
28	**Federal Tax**	15.00%	N/A	15.00%
29	**Provincial Tax**	11.00%	N/A	11.00%
30	**Provincial Manufacturing & Processing Profits Deduction**	-1.00%	N/A	-1.00%
31	**Total Income Tax Rate**	25.00%	N/A	25.00%

For notes see Table 7a.

Numbers may not add due to rounding.

Table 7a
Notes to Table 7
Summary of Changes in Regulatory Income Taxes for Prescribed Facilities ($M)
Year Ending December 31, 2012

Notes:

1 "OPG Proposed" amounts agree to Ex. F4-T2-S1 Table 5, col. (c) as filed in EB-2010-0008, with the exception of lines 1, 7, 8, 19 and 22, which changed to reflect audited balances in variance and deferral accounts as at December 31, 2010. Specific changes are discussed in notes 2 through 6 below.

2 Regulatory Earnings Before Tax for 2012 are calculated as follows:

Table to Note 2 - Calculation of Regulatory EBT for 2012 ($M)

Line No.	Item	Reference	OPG Proposed	Board Adjustment	Board Approved
			(a)	(b)	(c)
1a	Requested After Tax Return on Equity	"OPG Proposed" per EB-2010-0008 Ex. F4-T2-S1 Table 5, Note 1, line 1. "Board Approved" per Payment Amounts Order, Appendix A, Table 5b, col (d), line 5.	298.5	(22.8)	275.7
2a	Less: Bruce Lease Net Revenues	EB-2010-0008 Ex. F4-T2-S1 Table 5, Note 1, line 2	143.0	0.0	143.0
3a	Add: Single Payment Amounts Adjustment	EB-2010-0008 Ex. F4-T2-S1 Table 5, Note 1, line 3	(7.4)	19.5	12.1
4a		line 1a - line 2a + line 3a	148.1	(3.3)	144.8
5a	Additions for Regulatory Tax Purposes	line 13 (where line 13 refers to EB-2010-0008 Payment Amounts Order, Appendix A, Table 7)	1,026.2	0.0	1,026.2
6a	Deductions for Regulatory Tax Purposes	line 23 (where line 23 refers to EB-2010-0008 Payment Amounts Order, Appendix A, Table 7)	894.1	0.0	894.1
7a		line 4a + line 5a - line 6a	280.2	(3.3)	276.8
8a	Regulatory Income Taxes - Federal	line 7a x line 28 / (1 - line 31) (where lines 28 and 31 refer to EB-2010-0008 Payment Amounts Order, Appendix A, Table 7)	56.0	(0.7)	55.4
9a	Regulatory Income Taxes - Provincial	(line 7a - line 11) x (line 29 + line 30) / (1- line 31) (where lines 11, 29, 30 and 31 refer to EB-2010-0008 Payment Amounts Order, Appendix A, Table 7)	36.2	(0.4)	35.7
10a	Total Regulatory Income Taxes	line 8a + line 9a	92.2	(1.1)	91.1
11a	Requested After Tax Return on Equity	line 1a	298.5	(22.8)	275.7
12a	Less: Bruce Lease Net Revenues	line 2a	143.0	0.0	143.0
13a	Add: Total Regulatory Income Taxes	line 10a	92.2	(1.1)	91.1
14a	Add: Single Payment Amounts Adjustment		(7.4)	19.5	12.1
15a	Regulatory Earnings Before Tax	line 11a - line 12a + line 13a + line 14a	240.3	(4.4)	235.9

3 "OPG Proposed" amount reflects the audited balance of the Bruce Lease Net Revenues Variance Account as at December 31, 2010. The amount is equal to the amortization of the account balance in 2012 as per Payment Amounts Order, Appendix E, Table 1, col. (f), line 8.

4 "OPG Proposed" amount reflects the amortization of the portion of the audited balance of the Income and Other Taxes Variance Account as at December 31, 2010 pertaining to variances that are not deductible for tax purposes.

5 "OPG Proposed" amount reflects the amortization of the tax deductible portion of the audited balance of the Nuclear Liability Deferral Account as at December 31, 2010.

6 "OPG Proposed" amount reflects the amortization of the interest improvement portion of the audited balance of the Bruce Lease Net Revenues Variance Account as at December 31, 2010.

Numbers may not add due to rounding.

Table 8
Annualized Residential Consumer Impact Assessment
Board Approved Revenue Requirement
Test Period January 1, 2011 to December 31, 2012

Line No.	Description	Notes	Test Period Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Typical Residential Consumer Usage (kWh/Month)**	1	800.0	800.0	800.0
2	**Gross-up for Line Losses**	2	1.0728	1.0728	1.0728
3	**OPG Portion**	3	14.0%	35.9%	49.9%
4	**Residential Consumer Usage of OPG Generation (kWh/Month)**		119.9	308.2	428.2
	(line 1 x line 2 x line 3)				
	IMPACT OF RECOVERY OF REVENUE REQUIREMENT DEFICIENCY (SUFFICIENCY):				
5	**Revenue Requirement Deficiency (Sufficiency) Approved for Recovery ($M)**	4	(32.5)	(133.5)	(166.0)
6	**Impact of Amortization of Variance and Deferral Account Amounts ($M)**	5	(60.2)	216.8	156.7
7	**Amount to be Recovered From Customers ($M)** (line 5 + line 6)		(92.6)	83.3	(9.3)
8	**Forecast Production (TWh)**	6	39.7	101.9	141.6
9	**Required Recovery ($/MWh)** (line 7 / line 8)		(2.34)	0.82	(0.07)
10	**Typical Monthly Consumer Bill Impact ($)**		(0.28)	0.25	(0.03)
	(line 4 x line 9)				
11	**Typical Monthly Residential Consumer Bill ($)**	7	109.40	109.40	109.40
12	**Percentage Change in Consumer Bills**		-0.26%	0.23%	-0.03%
	(line 10 / line 11)				

Notes:
1. From EB-2010-0008 Ex. I1-T1-S2, Table 1, line 1.
2. From EB-2010-0008 Ex. I1-T1-S2, Table 1, line 2.
3. From EB-2010-0008 Ex. I1-T1-S2, Table 1, line 3, adjusted for production forecast increases per OEB Decision.
4. From Payment Amounts Order, Appendix A, Table 3, line 6.
5. For regulated hydroelectric, amortization from Payment Amounts Order, Appendix A, Table 1, line 25.
   For nuclear, amortization of $403.2M from Payment Amounts Order, Appendix A, Table 2, line 25, less the EB-2007-0905 approved Rider A of $2.00/MWh multiplied by the forecast nuclear production for March 1, 2011 to December 31, 2012 of 93.2 TWh per Payment Amounts Order, Appendix E, Table 1, line 16.
6. From Payment Amounts Order, Appendix A, Table 3, line 1.
7. From EB-2010-0008 Ex. I1-T1-S2, Table 1, line 11.

Numbers may not add due to rounding.

Table 8a

Computation of Per Cent Change in Payment Amounts
EB-2007-0905 to EB-2010-0008

Line No.	Description	EB-2007-0905 (OEB Approved) 2008 Apr 1-Dec 31	2009	Total	EB-2010-0008 (Draft Payment Amounts Order) 2011	2012	Total
		(a)	(b)	(c)	(d)	(e)	(f)
	AVERAGE RATE:						
1	**Regulated Hydroelectric Rate ($/MWh)**[1]			36.66			34.13
2	**Nuclear Rate ($/MWh)**[2]			54.98			55.85
3	**Forecast Regulated Hydroelectric Production**[3] **(TWh)**	12.9	18.5	31.4	19.8	19.8	39.7
4	**Forecast Nuclear Production**[3] **(TWh)**	38.3	49.9	88.2	50.4	51.5	101.9
5	**Total Forecast Production (TWh)** (line 3 + line 4)			119.6			141.6
6	**Regulated Hydroelectric Portion of Average Rate ($/MWh)** (line 1 x line 3 / line 5)			9.62			9.56
7	**Nuclear Portion of Average Rate ($/MWh)** (line 2 x line 4 / line 5)			40.55			40.20
8	**Total Average Rate ($/MWh)** (line 6 + line 7)			**50.17**			**49.77**
9	**RATE INCREASE (DECREASE) from EB-2007-0905 to EB-2010-0008**						
	(0.8%)						

Notes:

1 EB-2007-0905 amount from EB-2007-0905 Payment Amounts Order, December 2, 2008, Appendix B, Table 1, line 5.
EB-2010-0008 amount from draft EB-2010-0008 Payment Amounts Order, March 21, 2011, Appendix B, Table 1, line 3 plus line 5.

2 EB-2007-0905 amount from EB-2007-0905 Payment Amounts Order, December 2, 2008, Appendix C, Table 1, line 7 plus Appendix D, Table 1, line 9.
EB-2010-0008 amount from draft EB-2010-0008 Payment Amounts Order, March 21, 2011, Appendix C, Table 1line 3 plus line 5.

3 EB-2007-0905 amounts from EB-2007-0905 Payment Amounts Order, December 2, 2008, Appendix A, Table 3.
EB-2010-0008 amounts from draft EB-2010-0008 Payment Amounts Order, March 21, 2011, Appendix A, Table 3.

Numbers may not add due to rounding.

Table 1
Regulated Hydroelectric Payment Amount
Test Period January 1, 2011 to December 31, 2012

Line No.	Description	Test Period
		(a)
	PAYMENT AMOUNT:	
1	**Revenue Requirement[1] ($M)**	1,419.2
2	**Forecast Production[2] (TWh)**	39.7
3	**Payment Amount ($/MWh)**	35.78
	(line 1 / line 2)	
	DEFERRAL AND VARIANCE ACCOUNT PAYMENT RIDER:	
4	**Recovery of Variance and Deferral Account Amounts[3] ($M)**	(60.2)
5	**Payment Rider ($/MWh)** (line 4 / Mar 2011 - Dec 2012 Production[4])	(1.65)

Notes:

1 From Payment Amounts Order, Appendix A, Table 3, line 4.
2 From Payment Amounts Order, Appendix A, Table 3, line 1.
3 From Payment Amounts Order, Appendix A, Table 1, line 25.
4 March 2011 - December 2012 production from Payment Amounts Order, Appendix D, Table 1, line 10.

Numbers may not add due to rounding.

Table 1
Nuclear Payment Amount
Test Period January 1, 2011 to December 31, 2012

Line No.	Description	Test Period
		(a)
	PAYMENT AMOUNT:	
1	**Revenue Requirement[1] ($M)**	5,251.5
2	**Forecast Production[2] (TWh)**	101.9
3	**Payment Amount ($/MWh)**	51.52
	(line 1 / line 2)	
	DEFERRAL AND VARIANCE ACCOUNT PAYMENT RIDER:	
4	**Recovery of Variance and Deferral Account Amounts[3] ($M)**	403.2
5	**Payment Rider ($/MWh)** (line 4 / Mar 2011 - Dec 2012 Production[4])	4.33

Notes:
1 From Payment Amounts Order, Appendix A, Table 3, line 4.
2 From Payment Amounts Order, Appendix A, Table 3, line 1.
3 From Payment Amounts Order, Appendix A, Table 2, line 25.
4 March 2011 - December 2012 Production from Payment Amounts Order, Appendix E, Table 1, line 16.

Numbers may not add due to rounding.

Table 1
Regulated Hydroelectric Payment Rider

Line No.	Account Description	Notes	Audited Dec. 31 2010 Balance (Note 1)	Board Adjustment	Board Approved Dec. 31 2010 Balance	Amortization Period (Months)	Amortization 2011 (Note 2)	Amortization 2012 (Note 3)	Total Amortization / Rider
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Hydroelectric Water Conditions Variance ($M)**		(70.2)	0.0	(70.2)	22.0	(31.9)	(38.3)	(70.2)
2	**Ancillary Services Net Revenue Variance - Hydroelectric ($M)**		(9.4)	0.0	(9.4)	22.0	(4.3)	(5.1)	(9.4)
3	**Income and Other Taxes Variance ($M)**		(8.1)	0.0	(8.1)	22.0	(3.7)	(4.4)	(8.1)
4	**Tax Loss Variance ($M)**		78.8	0.0	78.8	46.0	17.1	20.6	37.7
5	**Hydroelectric Interim Period Shortfall (Rider D) Variance ($M)**		(2.3)	0.0	(2.3)	22.0	(1.0)	(1.2)	(2.3)
6	**Hydroelectric Deferral and Variance Over/Under Recovery Variance ($M)**		(7.9)	0.0	(7.9)	22.0	(3.6)	(4.3)	(7.9)
7	**Total ($M)**		(19.1)		(19.1)		(27.3)	(32.8)	(60.2)
8	**2011 Production (March 1 - December 31) (TWh)[4]**								16.7
9	**2012 Production (TWh)[5]**								19.8
10	**Total Forecast Production (TWh)**								36.5
11	**Regulated Hydroelectric Payment Rider ($/MWh)**								(1.65)
	(line 7 / line 10)								

Notes:
1 Audited balances per "Schedule of Regulatory Balances as at December 31, 2010", as filed on Feb. 7, 2011 and referenced in Table 28 of EB-2010-0008 Decision with Reasons (p. 127).
2 Column (c) amount x 10 months / amortization period in column (d).
3 Column (c) amount x 12 months / amortization period in column (d).
4 From Payment Amounts Order, Appendix A, Table 3, col. (a), line 1, adjusted to remove forecast January and February 2011 production.
5 From Payment Amounts Order, Appendix A, Table 3, col. (b), line 1, adjusted to remove forecast January and February 2011 production.

Numbers may not add due to rounding.

Table 1
Nuclear Payment Rider

Line No.	Account Description	Notes	Audited Dec. 31 2010 Balance (Note 1)	Board Adjustment	Board Approved Dec. 31 2010 Balance	Amortization Period (Months)	Amortization 2011 (Note 2)	Amortization 2012 (Note 3)	Total Amortization / Rider
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Pickering A Return To Service (PARTS) Deferral ($M)**		33.2	0.0	33.2	10.0	33.2	0.0	33.2
2	**Nuclear Liability Deferral ($M)**		39.2	0.0	39.2	22.0	17.8	21.4	39.2
3	**Nuclear Development Variance ($M)**		(110.8)	0.0	(110.8)	22.0	(50.4)	(60.4)	(110.8)
4	**Transmission Outages and Restrictions Variance ($M)**		0.1	0.0	0.1	22.0	0.0	0.0	0.1
5	**Ancillary Services Net Revenue Variance - Nuclear ($M)**		0.6	0.0	0.6	22.0	0.3	0.3	0.6
6	**Capacity Refurbishment Variance ($M)**		(8.5)	0.0	(8.5)	22.0	(3.9)	(4.6)	(8.5)
7	**Nuclear Fuel Cost Variance ($M)**		6.4	0.0	6.4	22.0	2.9	3.5	6.4
8	**Bruce Lease Net Revenues Variance ($M)**		249.4	0.0	249.4	22.0	113.4	136.0	249.4
9	**Income and Other Taxes Variance ($M)**		(31.6)	0.0	(31.6)	22.0	(14.3)	(17.2)	(31.6)
10	**Tax Loss Variance ($M)**		413.7	0.0	413.7	46.0	89.9	107.9	197.8
11	**Nuclear Interim Period Shortfall (Rider B) Variance ($M)**		6.6	0.0	6.6	22.0	3.0	3.6	6.6
12	**Nuclear Deferral and Variance Over/Under Recovery Variance ($M)**		20.8	0.0	20.8	22.0	9.5	11.4	20.8
13	**Total ($M)**		619.0		619.0		201.4	201.8	403.2
14	**2011 Production (March 1 - December 31) (TWh)**[4]								41.7
15	**2012 Production (TWh)**[5]								51.5
16	**Total Forecast Production (TWh)**								93.2
17	**Nuclear Payment Rider ($/MWh)** (line 13 / line 16)								4.33

Notes:
1 Audited balances per "Schedule of Regulatory Balances as at December 31, 2010", as filed on Feb. 7, 2011 and referenced in Table 28 of EB-2010-0008 Decision with Reasons (p. 127).
2 Column (c) amount x 10 months / amortization period in column (d).
3 Column (c) amount x 12 months / amortization period in column (d), with the exception of the PARTS Deferral Account which is amortized until December 31, 2011.
4 From Payment Amounts Order, Appendix A, Table 3, column (d), line 1 adjusted to remove forecast January and February 2011 production.
5 From Payment Amounts Order, Appendix A, Table 3, col. (e), line 1, adjusted to remove forecast January and February 2011 production.

Appendix F: Variance and Deferral Accounts

CLEARANCE OF EXISTING VARIANCE AND DEFERRAL ACCOUNTS

With respect to the variance and deferral accounts established by O. Reg. 53/05 and the Board's decisions and orders in EB-2007-0905, EB-2009-0038 and EB-2009-0174, the Board approves the recovery of December 31, 2010 balances in these accounts and recovery periods as provided in the following tables:

Table F - 1
Regulated Hydroelectric Accounts

Account	Approved Dec 31, 2010 Balances ($M)	Approved Recovery Period	
		Starting	Ending
Hydroelectric Water Conditions Variance	(70.2)	Mar 1, 2011	Dec 31, 2012
Ancillary Services Net Revenue Variance - Hydroelectric	(9.4)	Mar 1, 2011	Dec 31, 2012
Income and Other Taxes Variance	(8.1)	Mar 1, 2011	Dec 31, 2012
Tax Loss Variance	78.8	Mar 1, 2011	Dec 31, 2014
Hydroelectric Interim Period Shortfall (Rider D) Variance	(2.3)	Mar 1, 2011	Dec 31, 2012
Hydroelectric Deferral and Variance Over/Under Recovery Variance	(7.9)	Mar 1, 2011	Dec 31, 2012

Table F - 2
Nuclear Accounts

Account	Approved Dec 31, 2010 Balances ($M)	Approved Recovery Period	
		Starting	Ending
Pickering A Return To Service Deferral	33.2	Mar 1, 2011	Dec 31, 2011
Nuclear Liability Deferral	39.2	Mar 1, 2011	Dec 31, 2012
Nuclear Development Variance	(110.8)	Mar 1, 2011	Dec 31, 2012
Transmission Outages and Restrictions Variance	0.1	Mar 1, 2011	Dec 31, 2012
Ancillary Services Net Revenue Variance - Nuclear	0.6	Mar 1, 2011	Dec 31, 2012
Capacity Refurbishment Variance	(8.5)	Mar 1, 2011	Dec 31, 2012
Nuclear Fuel Cost Variance	6.4	Mar 1, 2011	Dec 31, 2012
Bruce Lease Net Revenues Variance	249.4	Mar 1, 2011	Dec 31, 2012
Income and Other Taxes Variance	(31.6)	Mar 1, 2011	Dec 31, 2012
Tax Loss Variance	413.7	Mar 1, 2011	Dec 31, 2014
Nuclear Interim Period Shortfall (Rider B) Variance	6.6	Mar 1, 2011	Dec 31, 2012
Nuclear Deferral and Variance Over/Under Recovery Variance	20.8	Mar 1, 2011	Dec 31, 2012

The Board approves OPG's recovery of the approved balances in the regulated hydroelectric variance and deferral accounts using a payment rider. A payment rider of $(1.65)/MWh (Regulated Hydroelectric Payment Rider), determined in Appendix D, Table 1, effective March 1, 2011, shall apply to OPG's regulated hydroelectric production.

The Board approves OPG's recovery of the approved balances in the nuclear variance and deferral accounts using a payment rider. A payment rider of $4.33/MWh (Nuclear Payment Rider) determined in Appendix E, Table 1, effective March 1, 2011, shall apply to OPG's nuclear production.

For the period January 1, 2011 to February 28, 2011, OPG shall continue to record entries into the variance and deferral accounts established by O. Reg. 53/05 and the Board's decisions and orders in EB-2007-0905, EB-2009-0038 and EB-2009-0174 pursuant to the methodologies established by O. Reg. 53/05 and the above decisions and orders.

CONTINUING VARIANCE AND DEFERRAL ACCOUNTS

OPG shall continue the variance and deferral accounts listed below effective March 1, 2011, as follows:

<u>Hydroelectric Water Conditions Variance Account</u>

The Hydroelectric Water Conditions Variance Account shall continue to record the financial impact of differences between forecast and actual water conditions as proposed in OPG's application. OPG shall determine the production impact of changes in water conditions by entering the actual flow values into the same production forecast model used to calculate the Board approved production forecast, holding all other variables constant. OPG shall determine the deviations from forecast as the difference between the resulting production from the production forecast model based on actual flows and the energy production forecast approved by the Board. OPG shall determine the revenue impact of the production variance by multiplying the deviation from forecast, as described above, by the approved regulated hydroelectric payment amount of $35.78/MWh as calculated in Appendix B, Table 1. The resulting amount shall be recorded in the Hydroelectric Water Conditions Variance Account.

OPG shall also continue to 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 in 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 rate.

OPG shall also continue to record in this account any variations from the amounts payable to the St. Lawrence Seaway Management Corporation reflected in the revenue requirement approved by the Board for the conveyance of water in the Welland Ship Canal.

Ancillary Services Net Revenue Variance Account – Hydroelectric

OPG shall compare actual hydroelectric ancillary services net revenue to the forecast amount of $77.8 million, reflected in the revenue requirement approved by the Board. The difference shall continue to be recorded in this variance account. The ancillary services for regulated hydroelectric operations include black start capability, operating reserve, automatic generation control, and reactive support/voltage control service.

Income and Other Taxes Variance Account

The Income and Other Taxes Variance Account shall continue to record the financial impact on the revenue requirement approved by the Board 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 of $60.9 million for 2011 and $91.1 million for 2012, 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 6 and 7.

<u>Tax Loss Variance Account</u>

OPG shall record only interest and amortization in the Tax Loss Variance Account based on the approved recovery period.

<u>Hydroelectric Interim Period Shortfall (Rider D) Variance Account</u>

OPG shall record only interest and amortization in the Hydroelectric Interim Period Shortfall (Rider D) Variance Account based on the approved recovery period. The balance remaining in the account as at December 31, 2012 shall be transferred to the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account. Following this transfer, the Hydroelectric Interim Period Shortfall (Rider D) Variance Account shall be terminated on December 31, 2012.

<u>Hydroelectric Deferral and Variance Over/Under Recovery Variance Account</u>

The Hydroelectric Deferral and Variance Over/Under Recovery Variance Account shall record the differences between the amounts approved for recovery in the hydroelectric variance and deferral accounts and the actual amounts recovered resulting from the differences between the forecast and actual regulated hydroelectric production. The account shall also include the transfer of the balance remaining in the Hydroelectric Interim Period Shortfall (Rider D) Variance Account as at December 31, 2012.

Pickering A Return To Service Deferral Account

As the approved balance in this account as at December 31, 2010 is ordered to be cleared by December 31, 2011, OPG shall record amortization and interest only in the Pickering A Return To Service Deferral Account until December 31, 2011. The balance remaining in the account as at December 31, 2011 shall be transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account. Following this transfer, the Pickering A Return To Service Deferral Account shall be terminated on December 31, 2011.

Nuclear Liability Deferral Account

The Nuclear Liability Deferral 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 5.58 per cent.

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."

Nuclear Development Variance Account

The Nuclear Development Variance 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.

Transmission Outages and Restrictions Variance Account

The approved balance in the Transmission Outages and Restrictions Variance Account as at December 31, 2010 represents accumulated unrecovered interest. Therefore, OPG shall record only amortization in this account based on the approved recovery period. The balance remaining in the account as at December 31, 2012 shall be transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account. Following this transfer, the Transmission Outages and Restrictions Variance Account shall be terminated on December 31, 2012.

Ancillary Services Net Revenue Variance Account - Nuclear

OPG shall compare actual nuclear ancillary services net revenue to the forecast amount of $5.9 million, reflected in the revenue requirement approved by the Board. The difference shall continue to be recorded in this variance account. The ancillary services for nuclear operations include operating reserve and reactive support/voltage control service.

Capacity Refurbishment Variance Account

The Capacity Refurbishment Variance Account, pursuant to section 6(2)4 of O. Reg. 53/05, shall continue 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 O. Reg. 53/05 section 2 and those forecast costs and firm financial commitments reflected in the revenue requirement approved by the Board. This account shall include assessment costs and pre-engineering costs and commitments.

Nuclear Fuel Cost Variance Account

OPG shall record only interest and amortization in the Nuclear Fuel Cost Variance Account based on the approved recovery period. The balance remaining in the account as at December 31, 2012 shall be transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account. Following this transfer, the Nuclear Fuel Cost Variance Account shall be terminated on December 31, 2012.

Bruce Lease Net Revenues Variance Account

The Bruce Lease Net Revenues Variance 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, and (ii) OPG's actual revenues and costs in respect of the Bruce facilities.

The variance recorded in this account shall continue to be measured by comparing the Bruce lease revenues net of costs credited to customers through the approved nuclear payment amount of $51.52/MWh, as calculated in Appendix C, Table 1, to the actual Bruce lease revenues net of costs realized by OPG. The Bruce lease revenues net of costs credited to customers shall 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 using the forecast Bruce lease revenues net of costs reflected in the nuclear revenue requirement approved by the Board divided by the nuclear production forecast approved by the Board.

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 also continue to be recorded in this account.

Nuclear Interim Period Shortfall (Rider B) Variance Account

OPG shall record only interest and amortization in the Nuclear Interim Period Shortfall (Rider B) Variance Account based on the approved recovery period. The balance remaining in the account as at December 31, 2012 shall be transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account. Following this transfer, the Nuclear Interim Period Shortfall (Rider B) Variance Account shall be terminated on December 31, 2012.

Nuclear Deferral and Variance Over/Under Recovery Variance Account

The Nuclear Deferral and Variance Over/Under Recovery Variance Account shall record the differences between the amounts approved for recovery in the nuclear variance and deferral accounts and the actual amounts recovered resulting from the differences between the forecast and actual nuclear production. The account shall also include the transfer of the balances remaining in the Pickering A Return To Service Deferral Account as at December 31, 2011, the Transmission Outages and Restrictions Variance Account as at December 31, 2012, the Nuclear Fuel Cost Variance Account as at December 31, 2012 and the Nuclear Interim Period Shortfall (Rider B) Variance Account as at December 31, 2012.

NEW VARIANCE AND DEFERRAL ACCOUNTS

OPG shall establish the following two new accounts effective March 1, 2011:

Hydroelectric Surplus Baseload Generation Variance Account

OPG shall establish the Hydroelectric Surplus Baseload Generation Variance Account to record the financial impact of foregone production at its prescribed hydroelectric facilities due to surplus baseload generation (“SBG”).

OPG shall determine the revenue impact of SBG by multiplying the foregone production volume due to SBG by the approved regulated hydroelectric payment amount of $35.78/MWh as calculated in Appendix B, Table 1. The resulting amount shall be recorded in the Hydroelectric Surplus Baseload Generation Variance Account.

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 SBG. OPG shall determine amounts to be recorded in this account by multiplying the foregone production volume at its prescribed hydroelectric facilities due to SBG by the applicable gross revenue charge rate.

OPG shall also record in this account any variations from the amounts payable to the St. Lawrence Seaway Management Corporation reflected in the revenue requirement approved by the Board for the conveyance of water in the Welland Ship Canal as a result of foregone production at its prescribed hydroelectric facilities due to SBG.

The reconciliation of the account will be based on any IESO order or instructions (if applicable), general market conditions (e.g., total demand, total baseload, total supply) and actual production reports from the SBG-affected prescribed generation units that show deviations from production that are contemporaneous with SBG conditions.

Hydroelectric Incentive Mechanism Variance Account

OPG shall establish the Hydroelectric Incentive Mechanism (“HIM”) Variance Account to record 50 per cent of HIM net revenues above $10M in 2011 and $14M in 2012 as a credit to ratepayers.

INTEREST

Except for the Nuclear Liability Deferral Account, OPG shall record interest on the balances in the variance and deferral 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.