EB-2007-0905

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: Gordon Kaiser
Presiding Member & Vice Chair

Cynthia Chaplin
Member

Bill Rupert
Member

PAYMENT AMOUNTS ORDER

December 2, 2008

Ontario Power Generation Inc. (“OPG”) filed an application dated November 30, 2007 with the Ontario Energy Board (the “Board”) under section 78.1 of the *Ontario Energy Board Act; S.O. 1998*, c. 15, Sched. B for an order or orders approving the payment amounts for generating facilities prescribed under Ontario Regulation 53/05 (“O. Reg. 53/05”), as amended, for the period from April 1, 2008 through December 31, 2009 (the “test period”). The Board assigned file number EB-2007-0905 to the Application.

On February 7, 2008, the Board heard a Motion by OPG for an order declaring OPG’s current payment amounts interim, effective April 1, 2008 and an interim order increasing OPG's payment amounts on an interim basis. The Board granted OPG’s request to declare its current payment amounts interim, effective April 1, 2008, and denied its request for an interim increase in payment amounts.

The Board held an oral hearing on OPG’s application and issued a Decision with Reasons (“Decision”) on November 3, 2008. In the Decision, the Board directed OPG to file “… a draft order which will include the final revenue requirement and payment amounts for the prescribed nuclear and hydroelectric facilities, and reflect the findings made by the Board in this Decision”. With respect to the calculation of payment amounts, the Board indicated that OPG should assume that the Independent Electricity System Operator (“IESO”) would start billing the new payment amounts as of December 1, 2008 and that the payment amounts would be adjusted through the use of a payment rider to allow for the recovery of the 21 month revenue requirement over the period December 1, 2008 to December 31, 2009.

In the Decision the Board directed OPG to revise its calculation of the forecast net revenues related to OPG’s lease of the Bruce nuclear facilities to reflect the findings in the Decision and to establish a variance account to capture differences between (i) the forecast cost and revenues related to Bruce that are factored into the test period payment amounts for Pickering and Darlington, and (ii) OPG’s actual revenues and costs in respect of Bruce.

The Board also directed OPG to calculate the test period income tax provision, before consideration of any tax loss carry-forwards, consistent with the revenue requirement determined in accordance with the Decision, to establish a benchmark to measure variations in taxes during the test period for the purposes of the approved tax variance account.

The Board directed that the return on a portion of the rate base be limited to the average accretion rate on OPG’s nuclear liabilities which is currently 5.6%. The portion of the rate base attracting that return is equal to the lesser of: (i) the forecast amount of the average unfunded nuclear liabilities related to the Pickering and Darlington facilities, and (ii) the average unamortized asset retirement costs included in the fixed asset balances for Pickering and Darlington. The Board directed OPG to provide a test period forecast of the average unfunded nuclear liabilities related to Pickering and Darlington for the purposes of this determination.

On November 13, 2008, OPG filed a draft Payment Amounts Order ("draft order"). Canadian Manufactures and Exporters ("CME"), the Association of Major Power Consumers ("AMPCO"), the IESO and Board staff filed submissions on the draft order. The Consumers Council of Canada, the Vulnerable Energy Consumers Coalition and the School Energy Coalition filed letters supporting CME's submission. On November 25, 2008, OPG filed a reply to the intervenor and Board staff submissions.

The Board has reviewed and considered all submissions, and its decision is reflected in this Order and the Appendices to this Order. The Board has provided brief reasons below concerning certain of the issues.

Calculation and Recovery of Interim Period Shortfall

The Decision, at pages 177-178, requires "that OPG remains at risk for its production forecast in the same way it would have been had the payments amounts been set on a prospective basis." To achieve the production risk exposure set out in its Decision, the Board directs that the new payment amounts be set using the forecast production for the test period and that the interim period shortfall be calculated using the actual production during the interim period (April 1, 2008 through November 30, 2008). The Board notes that it will be necessary to use forecast production for November 2008. Payment riders B and D to this Order have been calculated to reflect the Board's direction. To ensure that OPG is kept whole, the Board also directs that nuclear and hydroelectric variance accounts be established to record the difference between the calculated interim period shortfall and the amounts recovered through the interim period shortfall payment riders B and D.

The IESO'S Treatment of the Interim Period Shortfall

In its draft order, OPG included a provision stipulating how the IESO should collect the interim period shortfall, specifically that the interim period shortfall would be collected from wholesale customers based on their past consumption. In its submissions, the IESO suggested that a fixed monthly amount should be used, rather than a payment rider, as applying a payment rider to past consumption would be complicated. OPG agreed with the IESO's proposal. The Decision stated at page 177, "OPG should assume that the IESO can start billing the new rates as of December 1, 2008 and that the payment amounts will be adjusted through the use of a rider to allow for the recovery of the 21 month revenue requirement over the 13 month period remaining in the test period." This implies collection of the interim period shortfall over future consumption not past consumption. It is also the Board's standard practice that larger interim period shortfalls be collected through rate riders charged on future consumption.

The Board directs that OPG recover its interim period shortfall through the application of payment riders B and D to OPG’s actual nuclear and hydroelectric production during the period December 1, 2008 to December 31, 2009 and the establishment of variance accounts to record any over or under-recovery of the shortfall by OPG.

Bruce Net Revenues and Test Period Income Tax Provision Benchmark

CME has proposed operative sections of the Order relating to the calculation of the Bruce Net Revenues and the Test Period Income Tax Provision Benchmark. OPG has not objected to those sections. The Board has included the operative sections in the Order.

Customer Impact Schedules

OPG provided an estimate of the residential customer impact related to the new payment amounts. CME requested a further calculation be done, with the impact stated explicitly in the Order. While the Board is mindful of customer impacts, the Board is of the view that it is not necessary or appropriate to refer to such impacts in the Order. Customer impacts can be calculated in a number of ways, depending upon specific circumstances, and there is no single measure of impact which is most appropriate. While the customer impact schedule is appended to this Order, no explicit reference to the customer impacts will be made in the Order.

Bruce Portion of the Unfunded Nuclear Liability

CME and AMPCO questioned the derivation of the Bruce portion of the unfunded nuclear liability. In response OPG filed an appendix with a detailed breakdown of the amount. The Board has included the filed appendix, at Appendix A table 8, with the Order.

Costs

The Board will be issuing direction on cost claims from eligible parties pertaining to the Order in due course.

THE BOARD THEREFORE ORDERS THAT:

1. The test period revenue requirement is $1,153.4 million for the prescribed hydroelectric facilities and $4,850.9 million for the prescribed nuclear facilities, as set out in Appendix A. These revenue requirements shall form the basis of the payment amounts, including the authorized payment riders. These amounts

include the revised calculation of the forecast net revenues related to OPG's lease of the Bruce nuclear facilities as set out in Appendix A.

2. Effective April 1, 2008, for the prescribed nuclear facilities, the payment amount is $52.98/MWh, as set out in Appendix C, plus the deferral/variance account payment rider and the interim period shortfall payment riders set out in sections 3 and 4.

3. Effective April 1, 2008, for the prescribed nuclear facilities, the nuclear payment rider A for the amortization of approved variance and deferral account balances is $2.00/MWh, as set out in Appendix D.

4. Effective December 1, 2008 to December 31, 2009, for the prescribed nuclear facilities, the nuclear payment rider B is $1.99/MWh and the nuclear payment rider C is $1.23/MWh, as set out in Appendix E. Nuclear payment rider B provides for the recovery of the difference between interim payment amount and $52.98/MWh for the period April 1, 2008 to November 30, 2008. Nuclear payment rider C provides for the recovery of nuclear payment rider A for the period April 1, 2008 to November 30, 2008.

5. Effective April 1, 2008 and subject to the incentive mechanism in section 7, for the prescribed hydroelectric facilities, the payment amount is $36.66/MWh, as set out in Appendix B, plus the interim period shortfall payment rider set out in section 6.

6. Effective December 1, 2008 to December 31, 2009, for the prescribed hydroelectric facilities, the hydroelectric payment rider D is $2.18/MWh, as set out in Appendix E. Hydroelectric payment rider D provides for the recovery of the difference between interim payment amount and $36.66/MWh for the period April 1, 2008 to November 30, 2008. This payment rider will be applied to the hourly volumes as set out in section 7 b).

7. a) For the period April 1, 2008 – November 30, 2008, if the total combined output of the prescribed hydroelectric facilities exceeds 1,900 megawatt hours in any hour, the hydroelectric payment amount applies to output from the prescribed facilities up to 1,900 MWh in any hour and production over 1,900 MWh in any hour receives the market price from the IESO–administered energy market determined under the market rules.

b) Effective December 1, 2008, the hydroelectric payment amount applies to the average hourly net energy production in megawatt hours from the prescribed hydroelectric facilities in any given month (the “hourly volume”) for each hour of that month. Net energy production over the hourly volume that is supplied into the IESO-administered energy market will receive the market price, calculated on a five minute basis. Where net energy production from the regulated hydroelectric facilities that is supplied into the IESO-administered energy market is less than the hourly volume, OPG’s revenues will be adjusted by the difference between the hourly volume and the actual net energy production that is supplied into the IESO-administered energy market at the market price, calculated on a five minute basis.

8. The IESO shall make payments to OPG in accordance with this Order as of December 1, 2008.

9. OPG shall recover the balances in the following variance and deferral accounts in accordance with Appendix F:

   – Hydroelectric Water Conditions Variance Account
   – Ancillary Services Net Revenue Variance Account
   – Transmission Outages and Restrictions Variance Account
   – Pickering A Return to Service Deferral Account
   – Nuclear Liability Deferral Account, Transition
   – Nuclear Development Deferral Account, Transition

10. OPG shall maintain the following variance and deferral accounts in accordance with Appendix F:

   – Hydroelectric Water Conditions Variance Account
   – Ancillary Services Net Revenue Variance Account
   – Pickering A Return to Service Deferral Account
   – Nuclear Liability Deferral Account
   – Nuclear Development Variance Account

11. OPG shall establish the following variance and deferral accounts in accordance with Appendix F:

   – Capacity Refurbishment Variance Account

- Nuclear Fuel Cost Variance Account
- Income and Other Taxes Variance Account
- Bruce Lease Net Revenues Variance Account
- Nuclear Interim Period Shortfall (rider B) Variance Account
- Hydroelectric Interim Period Shortfall (rider D) Variance Account

12. OPG shall calculate the benchmark income tax provision resulting from the revenue requirement described in section 1 of this Order, with the amount thereof being without prejudice to the rights of interested parties to question the appropriateness of OPG's benchmark income tax provision in a subsequent proceeding. Once approved by the Board, the benchmark income tax provision shall be used to calculate any variations in taxes recorded in the Income and Other Taxes Variance Account.

13. The revised calculation of the forecast net revenues related to OPG's lease of Bruce Facilities is set out in Appendix A table 7.

DATED at Toronto December 2, 2008

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

EB-2007-0905 PAYMENT AMOUNTS ORDER APPENDICES

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Table 1
Summary of Regulated Hydroelectric Revenue Requirement ($M)

Line No.	Description	Note	April 1 to December 31, 2008 OPG Proposed	April 1 to December 31, 2008 Board Adjust	April 1 to December 31, 2008 Board Approved	January 1 to December 31, 2009 OPG Proposed	January 1 to December 31, 2009 Board Adjust	January 1 to December 31, 2009 Board Approved	Total OPG Proposed	Total Board Adjust	Total Board Approved
			(a) Note 1	(b)	(c)	(d) Note 1	(e)	(f)	(g) Note 1	(h)	(i)
	Rate Base										
1	**Net Fixed Assets**		3,857.8	0.0	3,857.8	3,847.5	0.0	3,847.5	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**		21.8	0.0	21.8	21.8	0.0	21.8	N/A	N/A	N/A
4	**Total Rate Base**		3,880.2	0.0	3,880.2	3,869.9	0.0	3,869.9	N/A	N/A	N/A
	Capitalization										
5	**Short-term Debt**	2	99.4	16.7	116.1	99.6	15.9	115.5	N/A	N/A	N/A
6	**Long-Term Debt**	2	1,549.7	390.8	1,940.5	1,545.0	390.4	1,935.5	N/A	N/A	N/A
7	**Common Equity**	2	2,231.1	(407.4)	1,823.7	2,225.2	(406.3)	1,818.8	N/A	N/A	N/A
8	**Nuclear Liabilities**	2	0.0	0.0	0.0	0.0	0.0	0.0	N/A	N/A	N/A
9	**Total Capital**		3,880.2	(0.0)	3,880.2	3,869.9	(0.0)	3,869.9	N/A	N/A	N/A
	Cost of Capital										
10	**Short-term Debt**	3	5.8	0.9	6.7	6.0	0.9	6.9	11.8	1.9	13.6
11	**Long-Term Debt**	3	65.4	17.8	83.2	91.5	22.5	113.9	156.9	40.3	197.1
12	**Return on Equity**	3	175.7	(57.4)	118.3	233.6	(76.3)	157.3	409.3	(133.7)	275.7
13	**Nuclear Liabilities**	3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	**Total Cost of Capital**		246.9	(38.6)	208.3	331.1	(52.9)	278.2	578.0	(91.5)	486.4
	Expenses										
15	**OM&A**		93.1	0.0	93.1	119.0	0.0	119.0	212.1	0.0	212.1
16	**Fuel and GRC**		179.9	0.0	179.9	244.1	0.0	244.1	424.0	0.0	424.0
17	**Depreciation & Amortization**	4	45.9	6.9	52.8	61.6	9.3	70.9	107.5	16.2	123.7
18	**Property and Capital Taxes**		6.5	0.0	6.5	8.7	0.0	8.7	15.2	0.0	15.2
19	**Total Expenses**		325.4	6.9	332.3	433.3	9.3	442.6	758.7	16.2	774.9
	Less:										
	Other Revenues										
20	**Bruce Lease Revenues Net of Direct Costs**		N/A		N/A	N/A		N/A	N/A	0.0	N/A
21	**Ancillary and Other Revenue**	5	24.3	10.1	34.4	33.1	13.5	46.6	57.4	23.6	81.0
22	**Total Other Revenues**		24.3	10.1	34.4	33.1	13.5	46.6	57.4	23.6	81.0
23	**Income Tax**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Revenue Requirement before Mitigation**		548.0	(41.8)	506.2	731.3	(57.1)	674.2	1,279.3	(98.9)	1,180.4

For notes see Table 1a.

Table 1a
Notes to Table 1
Summary of Regulated Hydroelectric Revenue Requirement ($M)

Notes:

1 Agrees to Exhibit K1-T1-S1 Tables 1 and 2 - Summary of Revenue Requirement for April to December of 2008, and January 1, 2009 to December 31, 2009.

2 Capitalization for OPG's combined regulated operations is provided in Payment Amounts Order App A Table 4 for April 1 to December 31, 2008 and Payment Amounts Order App A Table 5 for January 1, 2009 to December 31, 2009. The Board determined that a portion of OPG's rate base will earn a return limited to the average accretion rate on OPG's nuclear liabilities. Payment Amounts Order App A Tables 4 and 5 identify that portion of rate base. The remaining rate base is financed with 53% debt and 47% equity as determined by the Board. The impact on capital structure is provided in Payment Amounts Order App A Tables 4 and 5. These resulting capital structure amounts are allocated to regulated hydroelectric and nuclear based on their relative rate base amounts. OPG has directly assigned the portion of rate base financed at the average accretion rate to its nuclear operations; therefore the allocation of the remaining capital structure components must be revised to reflect the change in the nuclear rate base:

			Apr to Dec 2008	2009
Approved reg. hydroelectric rate base	(a)	App A Table 1 Line 4	3,880.2	3,869.9
Approved nuclear rate base	(b)	App A Table 2 Line 4	3,509.1	3,483.8
Financing directly assigned to nuclear rate base	(c)	App A Table 2 Line 8	(1,060.3)	(1,012.9)
Nuclear rate base financed by capital structure	(d) = (b) - (c)		2,448.8	2,470.9
Reg. hydroelectric allocation	(e) = (a) / ((a) + (d))		61.31%	61.03%
Nuclear allocation	(f) = (d) / ((a) + (d))		38.69%	38.97%

3 Cost of capital for OPG's combined regulated operations is provided in Payment Amounts Order App A Tables 4 and 5. The cost of capital is allocated between regulated hydroelectric and nuclear operations consistent with the capital structure allocation described in Note 2 above.

4 **Description of Adjustment to Amortization Expense**	**Apr to Dec 2008**	**2009**	**Total**
Remove revenue sharing from SMO transactions prior to OEB regulation in accordance with OEB Decision	6.9	9.3	16.2

5 **Description of Adjustment to Other Revenues**	**Apr to Dec 2008**	**2009**	**Total**
Inclusion of SMO revenues for test period per OEB Decision	4.9	6.6	11.5
Inclusion of Water Transfer revenues for test period per OEB Decision	5.2	6.9	12.1
Total OM&A Adjustments	10.1	13.5	23.6

Numbers may not add due to rounding.

Table 2
Summary of Nuclear Revenue Requirement ($M)

Line No.	Description	Note	April 1 to December 31, 2008 OPG Proposed	April 1 to December 31, 2008 Board Adjust	April 1 to December 31, 2008 Board Approved	January 1 to December 31, 2009 OPG Proposed	January 1 to December 31, 2009 Board Adjust	January 1 to December 31, 2009 Board Approved	Total OPG Proposed	Total Board Adjust	Total Board Approved
			(a) Note 1	(b)	(c)	(d) Note 1	(e)	(f)	(g) Note 1	(h)	(i)
	Rate Base										
1	**Net Fixed Assets**		2,787.7	0.0	2,787.7	2,696.0	0.0	2,696.0	N/A	N/A	N/A
2	**Working Capital**		705.4	0.0	705.4	771.8	0.0	771.8	N/A	N/A	N/A
3	**Cash Working Capital**		16.0	0.0	16.0	16.0	0.0	16.0	N/A	N/A	N/A
4	**Total Rate Base**		3,509.1	0.0	3,509.1	3,483.8	0.0	3,483.8	N/A	N/A	N/A
	Capitalization										
5	**Short-term Debt**	2	89.9	(16.7)	73.2	89.7	(15.9)	73.8	N/A	N/A	N/A
6	**Long-Term Debt**	2	1,401.4	(176.8)	1,224.6	1,390.9	(155.1)	1,235.8	N/A	N/A	N/A
7	**Common Equity**	2	2,017.7	(866.8)	1,150.9	2,003.2	(841.9)	1,161.4	N/A	N/A	N/A
8	**Nuclear Liabilities**	2	0.0	1,060.3	1,060.3	0.0	1,012.9	1,012.9	N/A	N/A	N/A
9	**Total Capital**		3,509.1	(0.0)	3,509.1	3,483.8	0.0	3,483.8	N/A	N/A	N/A
	Cost of Capital										
10	**Short-term Debt**	3	5.2	(0.9)	4.3	5.4	(1.0)	4.4	10.6	(1.9)	8.7
11	**Long-Term Debt**	3	59.2	(6.7)	52.5	82.4	(9.6)	72.8	141.6	(16.3)	125.3
12	**Return on Equity**	3	158.9	(84.2)	74.7	210.3	(109.9)	100.5	369.2	(194.1)	175.1
13	**Nuclear Liabilities**	3	0.0	44.5	44.5	0.0	56.7	56.7	0.0	101.2	101.2
14	**Total Cost of Capital**		223.3	(47.4)	175.9	298.1	(63.7)	234.3	521.4	(111.1)	410.3
	Expenses										
15	**OM&A**	4	1,662.7	(15.9)	1,646.8	2,168.7	(21.4)	2,147.3	3,831.4	(37.3)	3,794.1
16	**Fuel and GRC**		125.7	0.0	125.7	204.2	0.0	204.2	329.9	0.0	329.9
17	**Depreciation & Amortization**	5	277.2	19.6	296.8	388.9	26.4	415.3	666.1	46.0	712.1
18	**Property and Capital Taxes**		16.3	0.0	16.3	22.0	0.0	22.0	38.3	0.0	38.3
19	**Total Expenses**		2,082.0	3.7	2,085.7	2,783.8	5.0	2,788.8	4,865.8	8.7	4,874.5
	Less:										
	Other Revenues										
20	**Bruce Lease Revenues Net of Direct Costs**	6	51.8	28.2	80.0	82.6	29.3	111.9	134.4	57.5	191.9
21	**Ancillary and Other Revenue**		49.4	0.0	49.4	50.9	0.0	50.9	100.3	0.0	100.3
22	**Total Other Revenues**		101.2	28.2	129.4	133.4	29.3	162.7	234.6	57.5	292.1
23	**Income Tax**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Revenue Requirement before Mitigation**		2,204.1	(71.8)	2,132.3	2,948.4	(88.0)	2,860.4	5,152.5	(159.9)	4,992.6

For notes see Table 2a.

Table 2a
Notes to Table 2
Summary of Nuclear Revenue Requirement ($M)

Notes:

1 Agrees to Exhibit K1-T1-S1 Tables 1 and 2 - Summary of Revenue Requirement for April to December of 2008, and January 1, 2009 to December 31, 2009.

2 Capitalization for OPG's combined regulated operations is provided in Payment Amounts Order App A Table 4 for April 1 to December 31, 2008 and Payment Amounts Order App A Table 5 for January 1, 2009 to December 31, 2009. The capital structure is allocated between regulated hydroelectric and nuclear consistent with the capital structure allocation described in Payment Amounts Order App A Table 1a, Note 2. The resulting allocation ratios for nuclear operations are:

Nuclear allocation for April 1, 2008 to December 31, 2008 is:	38.69%
Nuclear allocation for January 1, 2009 to December 31, 2009 is:	38.97%

3 Cost of capital for OPG's combined regulated operations is provided in Payment Amounts Order App A Tables 4 and 5. The cost of capital is allocated between regulated hydroelectric and nuclear consistent with the capital structure allocation described in Payment Amounts Order App A Table 1a, Note 2

4 **Description of Adjustment to OM&A Expense**

	Apr to Dec 2008	2009	Total
Pickering A reduction of 10% to base OM&A budget	(14.9)	(20.1)	(35.0)
Nuclear advertising	(1.0)	(1.3)	(2.3)
Total Adjustment	(15.9)	(21.4)	(37.3)

5 **Description of Adjustment to Amortization Expense**

	Apr to Dec 2008	2009	Total
Reduced PARTS recovery period (Payment Amounts Order App D, Line 1 column (f) - (c))	24.0	32.4	56.4
Remove test period amortization of Pickering B refurbishment costs incurred prior to OEB regulation (Test period amortization = ($16.2M total recovery amount per OEB Decision x 33 month proposed amortization period) / 21 month test period)	(4.4)	(6.0)	(10.4)
Total Adjustment	19.6	26.4	46.0

6 See Payment Amounts Order App A Table 7 for details of the adjustment.

Table 3
Summary of Approved Revenue Deficiency by Technology ($M)
Test Period April 1, 2008 to December 31, 2009

Line No.	Description	Regulated Hydroelectric 2008 (Apr 1-Dec 31)	Regulated Hydroelectric 2009 Jan 1-Dec 31)	Regulated Hydroelectric Total	Nuclear 2008 (Apr 1-Dec 31)	Nuclear 2009 Jan 1-Dec 31)	Nuclear Total	Total Test Period
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Forecast Production (TWh)**[1]	12.9	18.5	31.5	38.3	49.9	88.2	N/A
2	**Prescribed Payment Amount ($/MWh)**[1]	33.0	33.0	33.0	49.5	49.5	49.5	N/A
3	**Indicated Production Revenue ($M)**[1]	427.1	611.1	1,038.1	1,897.7	2,470.2	4,367.9	5,406.0
	(line 1 * line 2)							
4	**Approved Revenue Requirement Before Mitigation ($M)**[2]	506.2	674.2	1,180.4	2,132.3	2,860.4	4,992.6	6,173.0
5	**Revenue Deficiency Before Mitigation ($M)**	79.1	63.1	142.2	234.6	390.2	624.7	767.0
	(line 4 - line 3)							
6	**Mitigation Prescribed By OEB: 22% of Revenue Deficiency**[3]	11.6	15.4	27.0	60.7	81.0	141.7	168.6
7	**Revenue Deficiency After Mitigation ($M)**	67.5	47.7	115.2	173.9	309.2	483.0	598.4
	(line 5 - line 6)							
8	**Revenue Requirement Reflected In Approved Payment Amounts**							
	(line 4 - line 6)	494.6	658.8	1,153.4	2,071.6	2,779.4	4,850.9	6,004.4

Notes:
1 EB-2007-0905 Ex. A1-T3-S1 Table 3
2 From Payment Amounts Order App A Table 1 (Reg. Hydro) and Payment Amounts Order App A Table 2 (Nuclear)
3 Mitigation determined as 22% of total revenue deficiency allocated to equalize payment amount increase between Nuclear and Regulated Hydroelectric:

	Reg. Hydro	Nuclear	Total
	27.0	141.7	168.6
2008 Portion: 9 months / 21 months	11.6	60.7	72.3
2009 Portion: 12 months / 21 months	15.4	81.0	96.4
Total Allocated by Technology	27.0	141.7	168.7

`

Table 4a
Summary of Changes in Capitalization and Cost of Capital: April 1, 2008 to December 31, 2008
OPG Proposed ($M)

Line No.	Note	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
			Note 1		Note 2	Note 3
		Capitalization and Return on Capital:				
1		**Short-term Debt**	189.3	2.6%	5.83%	11.0
2		**Existing/Planned Long-Term Debt**	2,197.2	29.7%	5.79%	95.4
3	4	**Other Long-Term Debt Provision**	753.9	10.2%	5.65%	29.2
4	5	**Total Debt**	3,140.4	42.5%	N/A	135.6
5	5	**Common Equity**	4,248.9	57.5%	10.50%	334.6
6	6	**Rate Base**	7,389.3	100%	N/A	470.3

Notes:

1 Capital components referenced at EB-2007-0905 Ex K1-T1-S1 Table 1, lines 5, 6 and 7 of column (g).

2 Cost rate (column (c)) for capital components is provided as per EB-2007-0905 Ex. C1-T2-S1 Table 3; however, cost of capital (column (d)) is only for 9 months.

3 Cost of capital referenced at EB-2007-0905 Ex K1-T1-S1 Table 1, lines 9, 10 and 11 of column (g).
Principal (column (a)) * Cost Rate (column (c)) prorated for April 1, 2008 to December 31, 2008 period.

4 Debt required to balance capital structure with proposed rate base. See EB-2007-0905 Ex. C1-T2-S2, Table 5b for interest rate calculation.

5 Capital structure and return on equity proposal per EB-2007-0905 Ex. C1-T2-S1. The typical calculation for total debt (cost of capital / total debt) is not applicable.

6 Rate base referenced at EB-2007-0905 Ex K1-T1-S1 Table 1, line 4, column (g). The typical calculation for rate base (cost of capital / rate base) is not applicable.

Table 4b
Summary of Changes in Capitalization and Cost of Capital: April 1, 2008 to December 31, 2008
Board Approved ($M)

Line No.	Note	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
					Note 1	
		Capitalization and Return on Capital:				
1	2	**Short-term Debt**	189.3	3.0%	5.83%	11.0
2	3	**Existing/Planned Long-Term Debt**	2,092.0	33.1%	5.79%	90.4
3	4	**Other Long-Term Debt Provision**	1,073.1	17.0%	5.63%	45.3
4	5	**Total Debt**	3,354.4	53.0%	5.76%	146.7
5	5	**Common Equity**	2,974.6	47.0%	8.65%	193.0
6	6	**Rate Base Financed by Capital Structure**	6,329.0	85.7%	N/A	339.7
7	6	**Average Unfunded Nuclear Liabilities**	1,060.3	14.3%	5.60%	44.5
8	7	**Approved Rate Base**	7,389.3	100.0%	N/A	384.2

Notes:

1 Cost rate (column (c)) for capital components is provided; however cost of capital (column (d)) is only for 9 months.

2 Short-term methodology to determine regulated portion of short-term debt, the cost rate and the amount proposed by OPG was approved.

3 Reflects OEB directive to adjust the allocation of existing long-term debt to regulated operations to reflect the Board's Decision with respect to the unfunded nuclear liabilities (Decision with Reasons, Pg. 165). The allocation ratio is applied to determine the regulated portion of company-wide borrowing. OPG allocates corporate-wide borrowing based on net assets as illustrated in EB-2007-0905 Ex. C1-T1-S2, Table 1. OPG has removed the unfunded nuclear liabilities from net fixed assets and applied the resulting ratio to the corporate-wide borrowing described in EB-2007-0905 Ex. C1-T1-S2 Table 4, line 22. The calculation of the revised allocation ratio of 54.9% for 2008 is:

	Regulated	Company	Allocation Ratio
Net assets per EB-2007-0905 Ex C1-T1-S2	6,924.6	11,917.0	58.1%
Remove unfunded nuclear liability for 2008 (see note 6 below)	1,060.3	1,221.0	
Revised net assets used to determine allocation ratio	5,864.3	10,696.0	54.8%

OPG's corporate-wide borrowing for 2008 is $3,182.4M as described in EB-2007-0905 Ex. C1-T1-S2 Table 4, line 22. Project financing of $348M in 2008 associated with regulated projects is directly assigned to regulated operations.

4 Debt required to balance capital structure with proposed rate base. Interest Rate of 5.63% approved by OEB.

5 OEB approved a Debt / Equity ratio of 53% debt, 47% equity and an 8.65% return on common equity.

6 The portion of rate base to be financed pursuant to the capital structure approved by the Board will not include the lesser of the forecast of the average unfunded liabilities related to Pickering and Darlington, and the average unamortized asset retirement costs included in fixed asset balances for Pickering and Darlington. Unfunded nuclear liabilities of $1,060.3M are removed from rate base financing as the amount is less than the average unamortized asset retirement costs as illustrated below:

1) Average unamortized asset retirement costs for 2008 stated in Decision With Reasons (Pg. 90):		1,227.0
2) Average unfunded nuclear liability		
Total Company per Ex. J7.1	1,221.0	
Bruce Lease portion	160.7	
Pickering / Darlington portion of average unfunded nuclear liabilities		1,060.3

7 The Board approved OPG's proposed rate base. Rate base is referenced at EB-2007-0905 Ex. K1-T1-S1 Table 1, line 4, column (g).

Table 5a
Summary of Changes in Capitalization and Cost of Capital: January 1, 2009 to December 31, 2009
OPG Proposed ($M)

Line No.	Note	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
			Note 1			Note 2
		Capitalization and Return on Capital:				
1		**Short-term Debt**	189.3	2.6%	5.98%	11.3
2		**Existing/Planned Long-Term Debt**	2,362.7	32.1%	5.79%	136.8
3	3	**Other Long-Term Debt Provision**	573.2	7.8%	6.47%	37.1
4	4	**Total Debt**	3,125.3	42.5%	5.93%	185.2
5	4	**Common Equity**	4,228.4	57.5%	10.50%	444.0
6	5	**Rate Base**	7,353.7	100%	8.55%	629.1

Notes:

1 Capital components referenced at EB-2007-0905 Ex. K1-T1-S1 Table 2, lines 5, 6 and 7 of column (c).

2 Cost of capital referenced at EB-2007-0905 Ex. K1-T1-S1 Table 2, lines 9, 10 and 11 of column (c).

3 Debt required to balance capital structure with proposed rate base. See EB-2007-0905 Ex. C1-T2-S2, Table 5b for interest rate calculation.

4 Capital structure and return on equity proposal per EB-2007-0905 Ex. C1-T2-S1.

5 Rate base referenced at EB-2007-0905 Ex. K1-T1-S1 Table 2, line 4, column (c).

Numbers may not add due to rounding.

Table 5b
Summary of Changes in Capitalization and Cost of Capital: January 1, 2009 to December 31, 2009
Board Approved ($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**	189.3	3.0%	5.98%	11.3
2	2	**Existing/Planned Long-Term Debt**	2,229.2	35.2%	5.79%	128.7
3	3	**Other Long-Term Debt Provision**	942.1	14.9%	6.16%	58.0
4	4	**Total Debt**	3,360.6	53.0%	5.89%	198.0
5	4	**Common Equity**	2,980.2	47.0%	8.65%	257.8
6	5	**Rate Base Financed by Capital Structure**	6,340.8	86.2%	7.19%	455.8
7	5	**Average Unfunded Nuclear Liabilities**	1,012.9	13.8%	5.60%	56.7
8	6	**Approved Rate Base**	7,353.7	100.0%	6.97%	512.5

Notes:

1 Short-term methodology to determine regulated portion of short-term debt, the cost rate and the amount proposed by OPG was approved.

2 Reflects OEB directive to adjust the allocation of existing long-term debt to regulated operations to reflect the Board's Decision with respect to the unfunded nuclear liabilities (Decision with Reasons, Pg. 165) described in Payment Amounts Order App A Table 4b, Note 3. The revised ratio for 2009 is:

	Regulated	Company	Allocation Ratio
Net assets per EB-2007-0905 Ex. C1-T1-S2	6,924.6	11,917.0	58.1%
Remove unfunded nuclear liability for 2008 (see note 5 below)	1,012.9	878.1	
Revised net assets used to determine allocation ratio	5,911.7	11,038.9	53.6%

OPG's corporate-wide borrowing for 2008 is $2,960.9M as described in EB-2007-0905 Ex. C1-T1-S2 Table 4, line 21. Project financing of $642.2M in 2009 associated with regulated projects is directly assigned to regulated operations.

3 Debt required to balance capital structure with proposed rate base. Interest rate of 6.16% approved by OEB for 2009.

4 OEB approved a Debt / Equity ratio of 53% debt, 47% equity and an 8.65% return on common equity.

5 The portion of rate base to be financed pursuant to the capital structure approved by the Board will not include the lesser of the forecast of the average unfunded liabilities related to Pickering and Darlington, and the average unamortized asset retirement costs included in fixed asset balances for Pickering and Darlington. Unfunded nuclear liabilities of $1,012.9M are removed from rate base financing as the amount is less than the average unamortized asset retirement costs as illustrated below:

1) Average uamortized asset retirement costs for 2009 stated in Decision With Reasons (Pg. 90):		1,121.0
2) Average unfunded nuclear liability		
Total company per Ex. J7.1	878.1	
Bruce Lease portion	(134.8)	
Pickering / Darlington portion of average unfunded nuclear liabilities		1,012.9

6 The Board approved OPG's proposed rate base. Rate base is referenced at EB-2007-0905 Ex. K1-T1-S1 Table 2, line 4, column (c).

Table 6
Typical Residential Customer Bill Impact
Board Approved Revenue Requirement Adjustments ($M)
Test Period April 1, 2008 to December 31, 2009

Line No.	Description	Test Period: Regulated Hydroelectric	Test Period: Nuclear	Test Period: Total
		(a)	(b)	(c)
1	**Typical Residential Consumer Usage (KWh/Month)[1]**	1,000.0	1,000.0	1,000.0
2	**Gross-up for Line Losses[2]**	1.0522	1.0522	1.0522
3	**OPG Portion[3]**	11.4%	31.9%	43.3%
4	**Residential Consumer Usage of OPG Generation (KWh/Month)**	119.8	336.0	455.8
	(line 1 * line 2 * line 3)			
	IMPACT OF RECOVERY OF APPROVED REVENUE REQUIREMENT:			
5	**Approved Revenue Deficiency After Mitigation[4]**	115.2	483.0	598.3
6	**Approved Production Forecast (TWh)[5]**	31.5	88.2	119.7
7	**Required Recovery ($/MWh)**	3.70	5.50	5.00
	(line 5 / line 6)			
8	**Typical Monthly Consumer Bill Impact ($)**	0.44	1.85	2.28
	(line 4 * line 7)			
9	**Typical Monthly Residential Consumer Bill ($)[6]**	111.63	111.63	111.63
10	**Percentage Increase in Consumer Bills**	0.40%	1.66%	2.05%
	(line 8 / line 9)			

Notes:
1 From EB-2007-0905 Ex K1-T1-S3 Table 1, line 1
2 From EB-2007-0905 Ex K1-T1-S3 Table 1, line 2
3 From EB-2007-0905 Ex K1-T1-S3 Table 1, line 3
4 From Payment Amounts Order App A Table 3, line 7
5 From Payment Amounts Order App A Table 3, line 1
6 From EB-2007-0905 Ex K1-T1-S3 Table 1, line 11

Numbers may not add due to rounding.

Table 7

Summary of Changes to Bruce Lease Revenues and Costs: April 1, 2008 to December 31, 2009 ($M)

Line No.	Description	April 1 to December 31, 2008 OPG Proposed	Board Adjust	Note	Board Approved	January 1 to December 31, 2009 OPG Proposed	Board Adjust	Note	Board Approved
		(a)	(b)		(c)	(d)	(e)		(f)
	Note 1		Note 2				Note 2		
	Revenues:								
1	Lease Revenue	257.4	20.7	3	278.1	263.2	15.5	3	278.7
2	Services Revenue	19.7	(7.7)	4	12.0	12.6	0.0		12.6
3	**Total Bruce Revenues**	277.1	13.0		290.1	275.8	15.5		291.3
	(line 1 + line 2)								
	Costs:								
4	Depreciation	77.5	(7.7)	5	69.8	66.7	0.0		66.7
5	Property Tax	15.2	0.0		15.2	15.5	0.0		15.5
6	Capital Tax	2.6	1.8	6	4.4	2.5	1.1	4	3.6
7	Used Fuel Storage and Management	14.1	0.0		14.1	14.8	0.0		14.8
8	Interest	28.4	(7.2)	7	21.2	27.6	(6.5)	5	21.1
9	Income Tax	0.0	37.7	8	37.7	0.0	37.7	6	37.7
10	Return on Equity	70.2	(70.2)	9	0.0	66.1	(66.1)	7	0.0
11	Earnings on Segregated Funds	0.0	(234.9)		(234.9)	0.0	(262.0)		(262.0)
12	Accretion on Nuclear Liabilities	0.0	255.9		255.9	0.0	282.0		282.0
13	**Total Bruce Costs**	208.0	(24.6)		183.4	193.2	(13.8)		179.4
14	**Revenues Less Costs**	69.1	37.6		106.7	82.6	29.3		111.9
	(line 3 - line 13)								
15	Adjust for Jan 1, 2008 to March 1, 2008	17.3	9.4		26.7	N/A	N/A		N/A
16	**Offset to Test Period Revenue**								
	Requirement	51.8	28.2		80.0	82.6	29.3		111.9
	(line 14 - line 15)								

For notes see Table 7a.

Table 7a
Notes to Table 7
Summary of Changes to Bruce Lease Revenues and Costs: April 1, 2008 to December 31, 2009 ($M)

Notes:

1 Lines 1 to 13 reflect annual values for 2008 and 2009. Adjustment to back-out January 1 - March 31 period for 2008 is made in Line 15.

2 Detail provided in EB-2007-0905 Ex. J8.1, Attachment 1 except as noted in Notes 4, 5 and 8 below.

		2008	2009
3	Bruce Lease Revenues: Adjust to accrual basis of revenue recognition	20.7	15.5
4	2008 revenue per Ex. J8.1 is $290.1M. The reconciliation provided in Ex. J8.1 lists only GAAP adjustments. The adjustment of ($7.7M) is a non-GAAP adjustment required to obtain $290.1M. The offsetting expense adjustment is shown in Note 5 below.	(7.7)	0.0
5	2008 depreciation per Ex. J8.1 is $69.8M. The reconciliation provided in Ex. J8.1 lists only GAAP adjustments. The adjustment of ($7.7M) is a non-GAAP adjustment required to obtain $69.8M. The offsetting revenue adjustment is shown in Note 4 above.	(7.7)	0.0
6	Capital Taxes: Replace amounts determined using regulatory methodology ($2.6M) with GAAP methodology ($4.4M)	(2.6)	(2.5)
	Apply GAAP based methodology	4.4	3.6
	Captial tax adjustment	1.8	1.1
7	Interest Expense: Replace deemed Interest on hypothetical capital structure	(28.4)	(27.6)
	Apply debt ratio and interest rates determined on a GAAP basis	21.2	21.1
	Interest expense adjustment	(7.2)	(6.5)
8	Income Tax: Remove taxes determined in accordance with rate regulated accounting	0.0	0.0
	Apply tax expense determined consistent with GAAP for unregulated operations	37.7	37.7
	Income tax adjustment	37.7	37.7
9	Eliminate return on equity.	(70.2)	(66.1)

Numbers may not add due to rounding.

EB-2007-0905
Appendix A
Table 8

Appendix B (from OPG rely comments Nov. 25, 2008)
Average Forecast Unfunded Nuclear Liabilities
April 1, 2008 to December 31, 2009

Line No.	Description	Note	April 1 to December 31, 2008[1]			January 1 to December 31, 2009[1]		
			Prescribed Assets	Bruce Assets	Total Nuclear	Prescribed Assets	Bruce Assets	Total Nuclear
			(a)	(b)	(c)	(d)	(e)	(f)
	ASSET RETIREMENT OBLIGATION							
1	**Opening Balance**	2, 3	5,921	4,860	10,781	6,182	5,025	11,207
2	**Forecast Closing Balance**	3	6,182	5,025	11,207	6,466	5,213	11,679
	NUCLEAR FUND BALANCE							
3	**Opening Balance**	2, 4	4,853	4,410	9,263	5,126	5,028	10,154
4	**Forecast Closing Balance**		5,126	5,028	10,154	5,496	5,480	10,976
	UNFUNDED BALANCE							
5	**Opening Balance** (line 1 - line 3)	2, 5	1,068	450	1,518	1,056	-3	1,053
6	**Adjustment: Remove January to March, 2008**	6	-4	-126	-130	0	0	0
7	**Opening Balance at April 1, 2008** (line 5 + line 6)		1,064	324	1,388	1,056	-3	1,053
8	**Forecast Closing Balance** (line 2 - line 4)		1,056	-3	1,053	970	-267	703
9	**Average Unfunded Balance**	7	1,060	161	1,221	1,013	-135	878
	(line 7 + line 8) / 2							

Notes:
1 Lines 1 through 5 are annual values. The adjustment for January 2008 to March 2008 is provided on line 6.
2 Balances in columns (a), (b) and (c) are actual values at December 31, 2007. Balances in columns (d), (e) and (f) are forecast values.
3 Year end balance from EB-2007-0905, Ex. J1.5.
4 The amount of nuclear segregated funds at December 31, 2007 was $9,263M per Ex. J15.1, Addendum, Pg. 1, line 44.
5 The total unfunded nuclear liability balance at December 31, 2007 was $1,518M per Ex. J15.1, Addendum, Pg. 2, line 5.
6 Net impact of increase in ARO and nuclear fund balance between January 1, 2008 and March 31, 2008.
7 2008 amounts used in Draft Rate Order Appendix A, Table 4b, Notes 3 and 6. 2009 amounts used in Draft Rate Order Appendix A, Table 5b, Notes 2 and 5.

Numbers may not add due to rounding.

Table 1
Regulated Hydroelectric Payment Amount
Test Period April 1, 2008 to December 31, 2009

Line No.	Description	Test Period
		(a)
	PAYMENT AMOUNT:	
1	**Approved Revenue Requirement before Mitigation ($M)**[1]	1,180.4
2	**Mitigation Required by OEB ($M)**[2]	27.0
3	**Approved Revenue Requirement Recovery**	1,153.4
	(line 1 - line 2)	
4	**Forecast Production (TWh)**[3]	31.5
5	**Board Approved Payment Amount ($/MWh)**	36.66
	(line 1 / line 4)	

Notes:
1 From Payment Amounts Order App A Table 3, line 4
2 From Payment Amounts Order App A Table 3, line 6
3 From Payment Amounts Order App A Table 3, line 1

Numbers may not add due to rounding.

Table 1
Nuclear Payment Amount
Test Period April 1, 2008 to December 31, 2009

Line No.	Description	Test Period
		(a)
	PAYMENT AMOUNT:	
1	**Approved Revenue Requirement before Mitigation ($M)**[1]	4,992.6
2	**Mitigation Required by OEB ($M)**[2]	141.7
3	**Approved Revenue Requirement Recovery**	4,850.9
	(line 1 - line 2)	
4	**Approved Recovery Amount of Deferral and Variance Account Balances ($M)**[3]	176.2
5	**Revenue Requirement to be Recovered Through Payment Amounts ($M)**	4,674.8
	(line 3 - line 4)	
6	**Forecast Production (TWh)**[4]	88.2
7	**Board Approved Payment Amount ($/MWh)**	52.98
	(line 5 / line 6)	

Notes:
1 From Payment Amounts Order App A Table 3, line 4
2 From Payment Amounts Order App A Table 3, line 6
3 From Payment Amounts Order App D Table 1, line 5, column (f)
4 From Payment Amounts Order App A Table 3, line 1

Numbers may not add due to rounding.

Table 1
Nuclear Variance and Deferral Account Rider: Nuclear Payment Riders A and C

Line No.	Account Description	Proposed Dec. 2007 Balance ($M)	Proposed Recovery Period Ending	Proposed Recovery Amount ($M)	Board Approved Dec. 2007 Balance ($M)	Note	Board Approved Recovery Period Ending	Board Approved Recovery Amount ($M)
		(a)	(b)	(c)	(d)		(e)	(f)
1	**Pickering A Return to Service**	183.80	Dec. 31, 2019	27.37	183.80	1	Dec. 31, 2011	85.8
2	**Nuclear Liability**	130.50	Dec. 31, 2010	83.05	130.50	2	Dec. 31, 2010	83.0
3	**Nuclear Development and Capacity Refurbishment**	27.90	Dec. 31, 2010	17.80	11.70	3	Dec. 31, 2010	7.4
4	**Ancillary Services Net Revenue (Nuclear) Plus Transmission Outages and Restrictions**	-0.10	Dec. 31, 2010	(0.1)	(0.1)		Dec. 31, 2010	(0.1)
5	**Total**	342.10		128.16	325.90			176.2
6	**Board Approved Production Forecast April 1, 2008 to Dec 31, 2008 (TWh)**			38.30		4		38.3
7	**Board Approved Production Forecast for 2009 (TWh)**			49.90		4		49.9
8	**Total Forecast Production April 1, 2008 to December 31, 2009**			88.20				88.2
9	**Nuclear Payment Rider--Recovery of Approved Deferral and Variance Account Amounts Effective April 1, 2008 (RIDER A)** (line 5 / line 8)			1.45				2.00
	Nuclear Payment Rider Adjustment To Provide For Recovery of April 1, 2008 to November 30, 2008 Amounts							
10	**Forecast Production for December, 2008 (TWh)**					5		4.6
11	**Board Approved Production Forecast for 2009 fiscal year**					4		49.9
12	**Total Forecast Production December 1, 2008 to December 31, 2009** (line 10 + line 11)							54.5
13	**Nuclear Payment Rider Effective December 1, 2008 ($/MWh):** (line 5 / line 12)							3.23
14	**Nuclear Payment Rider--Recovery of Approved Deferral and Variance Account Amounts for the April 1, 2008 to November 30, 2008 Period (RIDER C)** (line 13 - line 9)							1.23

Notes:

1 Recovery period reduced from 141 months to 45 months. Recovery is $183.8M x 21 months / 45 months.

2 The Board accepted the rate used, and the inclusion of the unamortized ARC relating to the Bruce nuclear station until the effective date of the OEB's first order.

3 Removal of capacity refurbishment costs of $16.2M including interest as per EB-2007-0905 Ex. J1-T1-S1 Table 8, column (d) rows 5 and 6.

4 From EB-2007-0905 Ex. J1-T2-S1 Table 3, lines 6 and 7.

5 Forecast production for December 2008 as per EB-2007-0905 Ex. E2-T1-S2, Table 1, line 7, column (l).

Table 1
Regulated Hydroelectric Interim Period Recovery Rider D
Test Period April 1, 2008 to December 31, 2009[1]

Line No.	Description	Test Period
		(a)
	REVENUE SHORTFALL--APRIL 1, 2008 to NOVEMBER 30, 2008:	
1	**Board Approved Payment Amount ($/MWh)[2]**	36.66
2	**Prescribed Payment Amount ($/MWh)**	33.00
3	**Payment Amount Increase ($/MWh)**	3.66
	(line 1 - line 2)	
4	**Production April 1, 2008 to November 30, 2008 (TWh)[3]**	11.94
5	**Revenue Shortfall April 1, 2008 to November 30, 2008 ($M)**	43.70
	(line 3 * line 4)	
	APPROVED PRODUCTION FORECAST--December 1, 2008 to December 31, 2009:	
6	**Forecast Production for December, 2008 (TWh)[4]**	1.56
7	**Board Approved Production Forecast for 2009 fiscal year (TWh)[5]**	18.52
8	**Total Forecast Production December 1, 2008 to December 31, 2009 (TWh)**	20.07
	(line 6 + line 7)	
	HYDROELECTRIC PAYMENT RIDER:	
9	**Hydroelectric Payment Rider D Effective December 1, 2008 ($/MWh)**	2.18
	(line 5 / line 8)	

Notes:

1 Based on actual energy production from April 1 to October 31, 2008, and forecast November 2008 energy production.

2 From Payment Amounts Order App B-T1 line 5.

3 From Payment Amounts Order App E-T4 line 1

4 From Payment Amounts Order App E-T2, Line 3 column (l).

5 From Payment Amounts Order App A-T3 line 1.

Numbers may not add due to rounding.

Table 2
Monthly Production Forecast - Regulated Hydroelectric (TWh)

Line No.	Regulated Hydroelectric	2008 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2008 Total	Apr 1 - Dec 31, 2008
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
															(sum (d) to (l))
1	**Production Forecast**	1.52	1.42	1.57	1.42	1.50	1.41	1.44	1.40	1.33	1.39	1.49	1.56	17.44	12.94

Line No.	Regulated Hydroelectric	2009 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2009 Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
2	**Production Forecast**	1.54	1.40	1.61	1.47	1.61	1.54	1.58	1.54	1.48	1.53	1.58	1.64	18.52

Numbers may not add due to rounding.

Table 3
Nuclear Interim Period Recovery Rider: Nuclear Payment Rider B
Test Period April 1, 2008 to December 31, 2009

Line No.	Description	Test Period
		(a)
	REVENUE SHORTFALL - April 1, 2008 to November 30, 2008:	
1	**Board Approved Payment Amount ($/MWh)**[2]	52.98
2	**Prescribed Payment Amount ($/MWh)**	49.50
3	**Payment Amount Increase ($/MWh)**	3.48
	(line 1 - line 2)	
4	**Energy Production April 1, 2008 to November 30, 2008 (TWh)**[3]	31.12
5	**Revenue Shortfall April 1, 2008 to November 30, 2008 ($M)**	108.28
	(line 3 * line 4)	
	APPROVED PRODUCTION FORECAST - December 1, 2008 to December 31, 2009:	
6	**Forecast Production for December, 2008 (TWh)**[4]	4.61
7	**Board Approved Production Forecast for 2009 fiscal year (TWh)**[5]	49.90
8	**Total Forecast Production December 1, 2008 to December 31, 2009 (TWh)**	54.51
	(line 6 + line 7)	
	NUCLEAR PAYMENT RIDER (RIDER B):	
9	**Nuclear Payment Rider--Recovery of Approved Revenue Deficiency**	1.99
	Amounts for the April 1, 2008 to November 30, 2008 Period (RIDER B) ($/MWh)	
	(line 5 / line 8)	

Notes:
1. Based on actual energy production from April 1 to October 31, 2008, and forecast November 2008 energy production.
2. From Payment Amounts Order App C-T1 , line 7
3. From Payment Amounts Order App E-T4 line 2
4. From EB-2007-0905 Ex E2-T1-S2 Table 1 (2008), line 7, column (l)
5. From Payment Amounts Order App A-T3 line 1

Numbers may not add due to rounding.

April to November 2008 Monthly Energy Production - Regulated Hydroelectric and Nuclear (MWh)[1]

Line No.	Production	2008 Actual[2] Apr	May	Jun	Jul	Aug	Sep	Oct	Forecast Nov[3]	Total Apr 1 - Nov 30 2008
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Regulated Hydroelectric**	1,586,313.726	1,584,908.335	1,444,095.172	1,543,175.465	1,492,480.402	1,392,342.196	1,409,865.217	1,486,106.000	11,939,286.513
2	**Nuclear**	3,388,149.728	3,231,621.756	3,720,556.623	4,129,088.295	4,172,656.803	4,155,496.406	4,341,134.067	3,977,454.400	31,116,158.078

Notes:

1 The production values in the table include all significant digits to enable the OEB to use these figures for calculations, if required.

2 Actual production values were provided by the IESO.

3 Regulated Hydroelectric values are from Payment Amounts Order Appendix E Table 2; Nuclear values are from EB-2007-0905 Ex. E2-S1-T2, Table 1 line 7, column (k).

Appendix F: Variance and Deferral Accounts

CLEARANCE OF EXISTING VARIANCE AND DEFERRAL ACCOUNTS

The Board approves the recovery of balances in the following variance accounts established under O. Reg. 53/05 for the period April 1, 2005 to March 31, 2008:

- Hydroelectric Water Conditions Variance Account
- Ancillary Services Net Revenue Variance Account (with sub-accounts for nuclear and hydroelectric)
- Transmission Outages and Restrictions Variance Account

With respect to the December 31, 2007 balances in these accounts, the Board approves the balances, recovery period and method of recovery as provided in the following table:

Account	Approved Balance	Recovery Period Ending	Method of Recovery
Hydroelectric Water Conditions	$6.7M	Dec 31, 2009	Hydroelectric Payment Amount
Ancillary Services Net Revenue, Hydroelectric sub-account	$6.7M	Dec 31, 2009	Hydroelectric Payment Amount
Ancillary Services Net Revenue, Nuclear sub-account	$1.6M	Dec 31, 2010	Nuclear Payment Rider
Transmission Outages and Restrictions	$(1.7)M	Dec 31, 2010	Nuclear Payment Rider

The Board approves the recovery of balances in the following deferral accounts established pursuant to O. Reg. 53/05 for the period April 1, 2005 to March 31, 2008:

- Pickering A Return to Service Deferral Account
- Nuclear Liability Deferral Account, Transition
- Nuclear Development Deferral Account, Transition

The Board approves the recovery of the December 31, 2007 balances in these accounts, the test period recovery amount and the recovery period as provided in the following table:

Account	Approved Balance	Recovery Period Ending	Test Period Recovery Amount
Pickering A Return to Service Deferral Account	$183.8M	Dec 31, 2011	$ 85.8M
Nuclear Liability Deferral Account	$130.5M	Dec 31, 2010	$ 83.0M
Nuclear Development Deferral Account, Transition	$ 11.7M	Dec 31, 2010	$ 7.4M
Total	$325.9M	Not applicable	$176.2M

The Board approves OPG's recovery of the test period recovery amount for the nuclear deferral accounts using a payment rider. A payment rider of $2.00/MWh (Nuclear Payment Rider A) determined in Appendix D, Table 1, effective April 1, 2008 shall apply to OPG's nuclear production for the period December 1, 2008 to December 31, 2009. Effective December 1, 2008, a second payment rider of $1.23/MWh (Nuclear Payment Rider C) determined in Appendix D, Table 1, shall apply to OPG's nuclear production for the period December 1, 2008 to December 31, 2009. Nuclear Payment Rider C shall enable OPG to recover amounts for Nuclear Payment Rider A for the period April 1, 2008 to November 30, 2008.

As the payment rider is based upon forecast production, any differences between forecast and actual production during the test period will cause a variance. This variance shall be carried forward to OPG's next payment application.

Existing Deferral and Variance Accounts
January 1, 2008 to March 31, 2008 Period

OPG shall continue to record differences between amounts reflected in its interim payment amounts authorized under O. Reg. 53/05 and OPG's actual costs/revenues incurred from December 31, 2007 to March 31, 2008 related to the following deferral and variance accounts:

- Hydroelectric Water Conditions Variance Account
- Ancillary Services Net Revenue Variance Account (with sub-accounts for nuclear and hydroelectric)

- Transmission Outages and Restrictions Variance Account
- Pickering A Return to Service Deferral Account
- Nuclear Liability Deferral Account, Transition
- Nuclear Development Deferral Account, Transition

OPG shall submit information to support amounts recorded post-December 31, 2007 in these accounts for disposition in OPG's next payment amounts application.

OPG shall record interest on the balances in accordance the interest rates established in O. Reg 53/05 until March 31, 2008. Effective April 1, 2008, OPG shall record interest on the balances in these accounts using the interest rates set by the Board from time to time pursuant to the Board's interest rate policy. OPG shall continue to apply interest to the opening monthly balance of these accounts until the balances are fully recovered.

CONTINUING VARIANCE AND DEFERRAL ACCOUNTS

OPG shall establish or continue, as applicable, the variance and deferral accounts listed below effective April 1, 2008.

OPG shall record interest on the balances in these accounts using the interest rates set by the Board from time to time pursuant to the Board's interest rate policy. OPG shall apply interest to the opening monthly balance of these accounts until the balances are fully recovered.

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

The Hydroelectric Water Conditions Variance Account shall record the financial consequences 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 provide the Board approved production forecast, holding all other variables the same. 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 for the test period. The monthly regulated hydroelectric production forecast approved by the Board is provided in Draft Rate Order Appendix E, Table 2. OPG shall determine the revenue impact by multiplying the deviation from forecast, as described above, by the hydroelectric payment amount of $36.66/MWh as calculated in Appendix B, Table 1. The resulting amount shall be recorded in the Hydroelectric Water Conditions Variance Account.

OPG shall also record in this account changes in the gross revenue charge payments as a result of differences in energy production (as provided above). OPG shall determine amounts to be recorded in this account by multiplying the deviation from production forecast as described above by the applicable gross revenue charge rate.

OPG shall also record in this account any variations from the payments included in OPG's application for the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal.

Ancillary Service Net Revenue Variance Account - Hydroelectric

OPG shall compare actual hydroelectric ancillary service net revenue to the forecast amount of $57.4M as reflected in the revenue requirement approved by the Board. Each month the difference shall be recorded in this variance account. The specific ancillary services for regulated hydroelectric operations are: black start capability, operating reserve, automatic generation control, and reactive support/voltage control service.

Ancillary Service Net Revenue Variance Account - Nuclear

OPG shall compare actual nuclear ancillary service net revenue to the forecast amounts of $5.4M as reflected in the revenue requirement approved by the Board. Each month the difference shall be recorded in this variance account. The specific ancillary services for nuclear operations included in the test period forecast are operating reserve and reactive support/voltage control service.

Pickering A Return to Service Deferral Account

OPG shall continue to record amounts in the Pickering A Return to Service Deferral Account established effective January 1, 2005 under to O. Reg. 53/05.

Nuclear Liability Deferral Account

OPG shall establish a Nuclear Liability Deferral Account effective April 1, 2008 under O. Reg. 53/05. The account shall record the revenue requirement impact of any change in its nuclear decommissioning liability arising from an approved reference plan. 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. OPG shall record the return on rate base using the average accretion rate on OPG's nuclear liabilities of 5.6% for the test period.

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 transfer the balance in the Nuclear Liability Deferral Account, Transition to this account effective April 1, 2008.

<u>Nuclear Development Variance Account</u>
OPG shall establish a Nuclear Development Variance Account effective April 1, 2008 pursuant to O. Reg. 53/05. The account shall record variances between the actual costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities during the test period and those approved by the Board.

OPG shall transfer the balance in the Nuclear Development Deferral Account, Transition to this account effective April 1, 2008.

NEW VARIANCE AND DEFERRAL ACCOUNTS
OPG shall record interest on the balances in these accounts using the interest rates set by the Board from time to time pursuant to the Board's interest rate policy. OPG shall apply interest to the opening monthly balance of these accounts until the balances are fully recovered.

OPG shall establish the following six new accounts effective April 1, 2008:

<u>Capacity Refurbishment Variance Account</u>
OPG shall establish a Capacity Refurbishment Variance Account pursuant to O. Reg. 53/05 section 6 (2) 4 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 generation facility referred to in O. Reg. 53/05 section 2 during the test period and those forecast costs approved by the Board. This account shall include assessment costs and pre-engineering costs and commitments.

<u>Nuclear Fuel Cost Variance Account</u>
OPG shall establish a Nuclear Fuel Cost Variance Account as proposed in its application to record the difference between the forecast and the actual cost of nuclear fuel expensed in the test period. OPG shall determine the variance based on the

variance in the total cost of the fuel bundles. OPG shall determine the difference between the nuclear fuel cost rate, expressed in $/MWh using the nuclear fuel cost as reflected in the revenue requirement approved by the Board and the production forecast approved by the Board, and the actual cost of nuclear fuel on a $/MWh basis. OPG shall apply this difference to its actual nuclear production during the test period. The resulting amount shall be recorded as the cost variance.

<u>Income and Other Taxes Variance Account</u>

OPG shall establish an Income and Other Taxes Variance Account as proposed in its application to record the financial impact on revenue requirement of:

- Any differences that result from a legislative or regulatory change to the tax rates or rules of the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), as modified by the regulations under the *Electricity Act, 1998* to determine payments in lieu of corporate income taxes and capital taxes and the regulations under the *Electricity Act, 1998* to determine payments in lieu of property tax to the Ontario Electricity Financial Corporation.
- Any differences in municipal property taxes that result from a legislative or regulatory change to the tax rates or rules for its regulated assets under the *Assessment Act, 1990*.
- Any differences 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 that OPG will incorporate in determining its actual payments in lieu of corporate income taxes and capital taxes.
- Any differences that result from tax assessments or re-assessments (including re-assessments associated with the application of these rates and rules to OPG's regulated operations or changes in assessing or administrative policy including court decisions on other taxpayers).

OPG shall calculate the income tax provision resulting from the revenue requirement approved by the Board and file it with the Board. That tax provision shall be used to calculate any variations in taxes recorded in the variance account.

<u>Bruce Lease Net Revenues Variance Account</u>

OPG shall establish a variance account to capture differences between (i) the forecast costs and revenues related to Bruce that are factored into the test period payment amounts for Pickering and Darlington, and (ii) OPG's actual revenues and costs in respect of Bruce. The revenues and costs factored into the test period payment amounts are detailed in Appendix A Table 7 of the Draft Rate Order. The cost impact of any changes in nuclear liabilities related to the Bruce stations shall also be recorded in this account.

Hydroelectric Interim Period Shortfall (rider D) Variance Account

This variance account shall record the difference between the hydroelectric revenue shortfall amount for the period effective from April 1, 2008 to November 30, 2008 and the hydroelectric payment rider D amounts recovered in the period effective from December 1, 2008 to December 31, 2009 based on actual hydroelectric production.

Carrying charges shall apply to the monthly opening balances in the account (exclusive of accumulated interest) at the rate of interest prescribed by the Board for the respective quarterly period.

The records supporting the entries in this account shall be kept so that the utility can furnish full information.

Nuclear Interim Period Shortfall (rider B) Variance Account

This variance account shall record the difference between the nuclear revenue shortfall amount for the period effective from April 1, 2008 to November 30, 2008 and the nuclear payment rider B amounts recovered in the period effective from December 1, 2008 to December 31, 2009 based on actual nuclear production.

Carrying charges shall apply to the monthly opening balances in the account (exclusive of accumulated interest) at the rate of interest prescribed by the Board for the respective quarterly period.

The records supporting the entries to this account shall be kept so that the utility can furnish full information.