ONTARIO POWER GENERATION

News from Ontario Power Generation

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August 12, 2005

ONTARIO POWER GENERATION RELEASES 2005 SECOND QUARTER FINANCIAL RESULTS

[Toronto]: Ontario Power Generation Inc. ("OPG" or the "Company") today reported its financial and operating results for the second quarter and six months ended June 30, 2005. Net income for the three months ended June 30, 2005 was $63 million or $0.25 per share compared to a net loss of $41 million or $0.16 per share for the same period in 2004. For the six months ended June 30, 2005, net income was $25 million or $0.10 per share compared to $23 million or $0.09 per share for the same period last year.

Effective April 1, 2005, the output from OPG's baseload hydroelectric and nuclear facilities became rate regulated, while output from its remaining hydroelectric facilities, and its fossil-fuelled and wind generating stations remain unregulated. However, the majority of the generation output from these unregulated facilities is subject to a revenue limit of 4.7¢/kWh to April 30, 2006. As a result of these changes and higher average Ontario spot market prices, during the second quarter of 2005, OPG received an average price of 4.9¢/kWh for the output from all of its generating facilities. While this was an increase compared to the average price of 4.1¢/kWh for the same period last year, it was considerably less than the average hourly Ontario electricity price (HOEP) of 6.1¢/kWh.

"Our second quarter financial results reflect higher realized electricity prices as well as increased production, compared to the second quarter of 2004. OPG's future earnings are forecast to improve as a result of the implementation of the regulatory changes effective April 1, 2005," said President and CEO Jim Hankinson.

Total production during the three months ended June 30, 2005 from OPG's generating stations was 25.5 TWh compared to 24.7 TWh during the same period in 2004. The increase in generation was primarily a result of higher fossil-fuelled generation attributable to improved reliability from these stations and higher electricity demand especially during a period of record high temperatures in June 2005. This increase was partly offset by the impact of a shutdown at Unit 4 of the Pickering A nuclear generating station for inspection and replacement of feeder pipes during the second quarter of 2005. The shutdown commenced on April 2, 2005 and Unit 4 remained out of service for the duration of the quarter. Unit 4 was returned to service on July 19, 2005. The increase in generation was also partly offset by a reduction in hydroelectric generation due to lower water levels and a decrease in generation from the Darlington nuclear generating station because of a higher number of planned outage days in the second quarter of 2005 compared to the same period in 2004.

For the six months ended June 30, 2005, total production from OPG's generating stations was 54.3 TWh compared to 52.9 TWh for the same period in 2004. The increase in generation was primarily a result of higher fossil-fuelled generation in the second quarter of 2005, reflecting improved station performance and higher electricity demand, and higher nuclear generation. Improved performance at the Pickering B and Darlington nuclear generating stations more than offset the impact of the maintenance shutdown of Unit 4 of the Pickering A nuclear generating station. Hydroelectric generation was negatively affected during the first six months of 2005 compared to the same period last year by lower water levels.

OPG's second quarter earnings were favourably impacted by an increase in gross margin from electricity sales primarily due to higher average sales prices during the second quarter of 2005 compared to the same period in 2004. OPG's average sales price increased as a result of higher average Ontario spot market prices resulting from record high temperatures in June 2005 and the introduction of regulated prices and other related regulatory changes effective April 1, 2005. These changes included the elimination of the Market Power Mitigation Agreement rebate and the introduction of a revenue limit on a significant portion of OPG's output from its unregulated generating stations. Earnings were also favourably impacted by the establishment of a deferral account for non-capital costs related to the Pickering A nuclear generating station return to service project as required by a regulation pursuant to the *Electricity Restructuring Act, 2004*.

The favourable impact of these changes in earnings during the second quarter of 2005 was partly offset by an impairment loss of $63 million related to Units 2 and 3 of the Pickering A nuclear generating station. In August 2005, following consideration of the costs and risks associated with returning these units to service, and taking into account the Company's current focus on improving the performance of its operating nuclear units, OPG's Board of Directors decided that while technically feasible, the return to service of these units was not justified on a commercial basis. Accordingly, an impairment loss representing the carrying value of these units was recorded.

Effective April 1, 2005, OPG adopted regulatory accounting for the rate regulated segments of its business. As a result, future income tax assets and liabilities associated with these segments are no longer recognized. Had OPG continued to account for income taxes using the liability method for the rate regulated segments, the future income tax expense would have increased by $53 million during the second quarter of 2005. Also, as part of this transition, OPG eliminated a net future income tax asset of $74 million and recorded a corresponding one-time extraordinary loss.

Earnings during the six months ended June 30, 2005 were favourably impacted by an increase in gross margin during the second quarter of 2005 primarily as a result of higher average sales prices, higher electricity generation during the six months ended June 30, 2005, and the deferral of non-capital costs related to the Pickering A return to service project commencing in 2005.

These favourable impacts were offset by an impairment loss on OPG's Lennox generating station of $202 million before tax, recorded during the first quarter of 2005, and the impairment loss on Units 2 and 3 of the Pickering A nuclear generating station.

Construction for the return to service of Unit 1 at the Pickering A nuclear generating station commenced in July 2004. As of June 30, 2005, the fieldwork execution was approximately 95 per cent complete. Total cumulative expenditures to the end of June 30, 2005 were $948 million. The major construction phase of the project was completed in July 2005 with the removal of Unit 1 from the guaranteed shutdown state. OPG is now conducting the commissioning phase, which is expected to be completed over a three month period before the unit is declared in commercial service in the fall of 2005. The schedule and cost to complete the project were impacted by the discovery of feeder pipe thinning in certain areas resulting in the need to perform additional inspections and the replacement of one feeder pipe. In addition, feeder issues resulted in the shutdown of Unit 4 at the Pickering A nuclear generating station. Resources were diverted from Unit 1 to address the Unit 4 feeder issue and complete other outage work, which also contributed to the extension of the Unit 1 project schedule. The costs related to the feeder inspection and replacement program, and the schedule extension were approximately $20 million. The projected costs to complete the project are approximately $1.0 billion, excluding the impact on costs of the feeder inspection and replacement, and the diversion of resources to Unit 4.

As part of the Ontario Government's plans to replace coal-fired generation, the Lakeview fossil generating station was closed in April 2005. In June 2005, the Government announced the timing for the closure of OPG's remaining coal-fired stations. Based on the Government's plan, the Thunder Bay generating station is scheduled to be converted to gas-fired generation in 2007. The Atikokan generating station is scheduled to close by the end of 2007, following the conversion of the Thunder Bay units and necessary transmission upgrades. The Lambton generating station is scheduled to be closed by the end of 2007 and the Nanticoke generating station is scheduled to have units closed through 2008, with the last unit scheduled to close in early 2009. OPG had recorded an impairment loss in 2003 and adjusted depreciation accordingly to reflect the Government's commitment to remove the coal-fired stations from service before the end of their previously estimated useful lives.

With the introduction of rate regulation effective April 1, 2005, OPG has revised its reporting segments to separately reflect the regulated and unregulated aspects of its operations. OPG's operating results are reported on a consolidated basis as well as by business segment. The business segments are: Regulated – Nuclear, Regulated – Hydroelectric, and Unregulated Generation. The segments reflect the manner in which strategies are formulated, operational decisions are made and performance is assessed.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars)	Three Months Ended June 30 2005	Three Months Ended June 30 2004	Six Months Ended June 30 2005	Six Months Ended June 30 2004
Earnings				
Revenue after Market Power Mitigation Agreement rebate and revenue limit rebate	1,373	1,141	2,731	2,491
Fuel expense	289	242	599	580
Gross margin	1,084	899	2,132	1,911
Operations, maintenance and administration	616	633	1,203	1,257
Other expenses	264	319	573	599
Impairment of long-lived assets	63	-	265	-
Income tax (recoveries) expenses	4	(12)	(8)	32
Extraordinary item	74	-	74	-
Net income (loss)	63	(41)	25	23
Cash flow				
Cash flow provided by (used in) operating activities	73	(146)	373	77
Electricity Generation (TWh)				
Regulated - Nuclear	9.4	10.0	21.4	20.4
Regulated - Hydroelectric	5.0	4.7	9.6	9.3
Unregulated Generation - Hydroelectric	4.4	5.3	8.2	9.5
Unregulated Generation - Fossil-fuelled	6.7	4.7	15.1	13.7
Total electricity generation	25.5	24.7	54.3	52.9
Average electricity sales price (¢/kWh)				
Regulated - Nuclear	4.9	4.0	4.6	4.1
Regulated - Hydroelectric	3.9[1]	4.2	4.1	4.2
Unregulated Generation	5.3[2]	4.1	4.8	4.3
OPG average sales price	4.9	4.1	4.6	4.2
Nuclear unit capability factor (per cent)				
Darlington	80.4	86.3	87.1	86.0
Pickering A	1.9	54.2	50.6	74.0
Pickering B	72.9	62.9	78.6	67.1
Equivalent forced outage rate (per cent)				
Regulated - Hydroelectric	0.5	3.3	0.6	2.1
Unregulated Generation - Hydroelectric	1.5	1.4	1.3	1.4
Unregulated Generation - Fossil-fuelled	16.8	31.6	16.1	27.6

[1] During the three months ended June 30, 2005, electricity generation from stations in the Regulated – Hydroelectric segment received a fixed price of 3.3¢/kWh for generation less than 1,900 MWh in any hour, and the average spot electricity market price for generation above this level.

[2] During the three months ended June 30, 2005, 85 per cent of the electricity generation from unregulated stations, excluding the Lennox generating station and other contract volumes, was subject to a revenue limit based on an average price of 4.7¢/kWh.

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our focus is on the efficient production and sale of electricity from our generation assets, while operating in a safe, open and environmentally responsible manner.

Ontario Power Generation Inc.'s unaudited consolidated financial statements and Management's Discussion and Analysis of financial condition and results of operations as at and for the three and six months ended June 30, 2005 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

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2005 SECOND QUARTER REPORT

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ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. ("OPG" or the "Company") as at and for the three and six months ended June 30, 2005. It should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, and MD&A as at and for the year ended December 31, 2004. OPG's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and are presented in Canadian dollars. This MD&A is dated August 11, 2005.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could" and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression will not, however, mean that a statement is not a forward-looking statement.

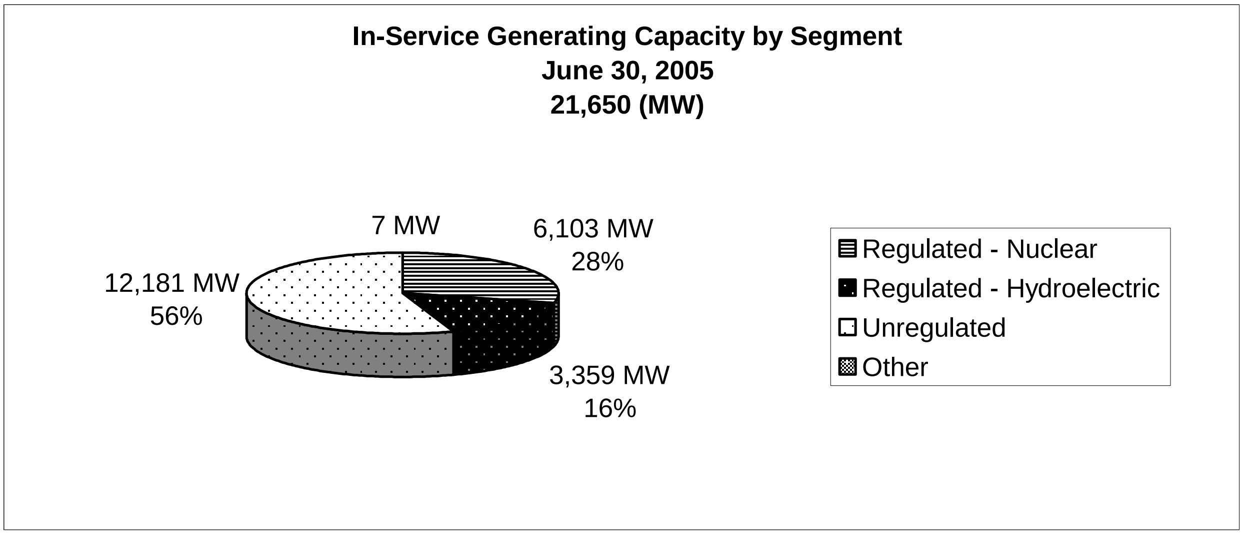
All forward-looking statements involve inherent assumptions, risks and uncertainties and, therefore, could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's return to service of units at the Pickering A nuclear generating station, fuel costs and availability, nuclear decommissioning and waste management, closure of coal-fired generating stations, pension and OPEB obligations, income taxes, spot market electricity prices, the ongoing evolution of the Ontario electricity industry, environmental and other regulatory requirements, and the weather. Accordingly, undue reliance should not be placed on any forward-looking statement.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG's focus is on the efficient production and sale of electricity from its generating assets, while operating in a safe, open and environmentally responsible manner. OPG was created under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the "Province").

At June 30, 2005, OPG had 21,650 megawatts (MW) of in-service generating capacity. OPG's electricity generating portfolio consisted of three nuclear generating stations, five fossil-fuelled generating stations, 64 hydroelectric generating stations and three wind generating stations (which includes a 50 per cent interest in the Huron Wind joint venture). All four units of the Pickering A nuclear generating station were laid up in 1997. Unit 4 was returned to service in 2003 and Unit 1 is expected to be returned to service in the fall of 2005. In addition, OPG, ATCO Power Canada Ltd. and ATCO Resources Ltd. co-own a gas-fired generating station. OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P. ("Bruce Power").

Effective April 1, 2005, the output from most of OPG's baseload hydroelectric facilities and all of its nuclear facilities became rate regulated. OPG continues to receive the spot market price for the output from its remaining hydroelectric, fossil-fuelled and wind generating stations, subject to a revenue limit. With the introduction of rate regulation, OPG has revised its reporting segments to separately reflect the regulated and unregulated aspects of its operations. OPG's operating results are reported on a consolidated basis as well as by business segment. The business segments are: Regulated – Nuclear, Regulated – Hydroelectric, and Unregulated Generation. The segments reflect the manner in which strategies are formulated, operational decisions are made and performance is assessed.



RATE REGULATION

A regulation was introduced pursuant to the *Electricity Restructuring Act, 2004*, which provided that, effective April 1, 2005, OPG would receive regulated prices for electricity generated from most of its baseload hydroelectric and all of its nuclear facilities. This includes electricity generated from Sir Adam Beck 1, 2 and Pump Generating Station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and Pickering A and B, and Darlington nuclear facilities.

The regulated price received by OPG for the first 1,900 megawatt hours (MWh) of production from the regulated hydroelectric facilities in any hour is $33.00/MWh (3.3¢/kWh). As an incentive to encourage maximum hydroelectric production during peak demand periods, any production from these regulated hydroelectric facilities above 1,900 MWh in any hour receives the unregulated Ontario spot market price. The regulated price received by OPG for production from the nuclear facilities is $49.50/MWh (4.95¢/kWh). These regulated prices were established by the Province, based on forecast production volumes and total operating costs, including the cost of capital and assuming an average five per cent return on equity. These initial prices took effect April 1, 2005, and are expected to remain in effect until at least March 31, 2008, at which time it is anticipated that the Ontario Energy Board ("OEB") will establish new regulated prices. If there are changes to the fundamental assumptions on which these regulated prices were developed, they may be amended by the Province.

The regulation directed OPG to establish a variance account for costs incurred on or after April 1, 2005 that are associated with differences in hydroelectric electricity production due to differences between forecast and actual water conditions; changes in nuclear electricity production due to unforeseen changes to the law or to unforeseen technological changes; changes to revenues assumed for ancillary revenues from the regulated facilities; acts of God (including severe weather events); and transmission outages and transmission restrictions. In addition, the regulation directed OPG to establish a deferral account for Pickering A return to service non-capital costs incurred on or after January 1, 2005.

The production from OPG's other generating assets remains unregulated and continues to be sold at the Ontario electricity spot market price. However, 85 per cent of the generation output from OPG's other generating assets, excluding the Lennox generating station, Transition – Generation Corporation Designated Rate Options ("TRO") volumes and forward sales as of January 1, 2005, are subject to a revenue limit based on an average price of $47.00/MWh (4.7¢/kWh). This revenue limit is in place for a period of 13 months ending April 30, 2006. Revenues above this limit will be rebated back to consumers at the end of the period.

The implementation of regulated pricing for the generation from OPG's baseload hydroelectric and nuclear facilities, as well as the revenue limit on OPG's unregulated generating assets, replaces OPG's rebate obligations under the Market Power Mitigation Agreement effective April 1, 2005.

EARNINGS OUTLOOK

Over the May 1, 2002 to March 31, 2005 period, OPG's earnings and liquidity were severely impacted by the requirement to rebate a significant portion of its revenues under the Market Power Mitigation Agreement. In total, the Market Power Mitigation Agreement rebate amounted to $4.0 billion over this period.

OPG's earnings are forecast to improve as a result of the implementation of the regulatory changes which took effect April 1, 2005. Earnings from OPG's regulated assets are forecast to improve as a result of the newly established prices that reflect the projected production and costs of operations, including a cost of capital with an average five per cent return on equity. Earnings on OPG's unregulated assets are also forecast to improve. While a significant portion of OPG's output from its unregulated assets is subject to the revenue limit until April 30, 2006, this limit is higher than the limit prescribed under the Market Power Mitigation Agreement.

HIGHLIGHTS/EXECUTIVE SUMMARY

This section provides an overview of OPG's consolidated operating results. A detailed review of OPG's performance by business segment is included in a later section.

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2005**	**2004**	**2005**	**2004**
Revenue				
Revenue	**1,514**	1,349	**3,284**	3,140
Market Power Mitigation Agreement rebate	**-**	(208)	**(412)**	(649)
Revenue limit rebate	**(141)**	-	**(141)**	-
	1,373	1,141	**2,731**	2,491
Earnings				
Income (loss) before impairment of long-lived assets, income taxes and extraordinary item	**204**	(53)	**356**	55
Impairment of long-lived assets	**63**	-	**265**	-
Income (loss) before income taxes and extraordinary item	**141**	(53)	**91**	55
Income tax (recoveries) expenses	**4**	(12)	**(8)**	32
Income (loss) before extraordinary item	**137**	(41)	**99**	23
Extraordinary item	**74**	-	**74**	-
Net income (loss)	**63**	(41)	**25**	23
Electricity production (TWh)	**25.5**	24.7	**54.3**	52.9
Cash flow				
Cash flow provided by (used in) operating activities	**73**	(146)	**373**	77

2005 Earnings

Net income for the three months ended June 30, 2005 was $63 million compared to a net loss of $41 million during the same period in 2004, an increase in earnings of $104 million. Income before tax and an extraordinary item during the three months ended June 30, 2005 was $141 million compared to a loss of $53 million for the same period in 2004, an increase of $194 million. During the second quarter of 2005, OPG recorded a one-time extraordinary loss to reflect the impact of adopting rate regulated accounting for income taxes effective April 1, 2005.

Net income for the six months ended June 30, 2005 was $25 million compared to a net income of $23 million during the same period in 2004, an increase of $2 million. Income before income taxes and the extraordinary item during the six months ended June 30, 2005 was $91 million compared to $55 million for the same period last year, an increase of $36 million.

The following is a summary of the factors impacting OPG's results for 2005 compared to 2004, on a before-tax basis:

(millions of dollars – before tax)	**Three Months**	**Six Months**
(Loss) income before income taxes for the periods ended June 30, 2004	**(53)**	**55**
Changes in gross margin		
Increase in electricity sales prices after Market Power Mitigation Agreement rebate and revenue limit rebate	153	154
(Decrease) increase in electricity sales volume from Regulated – Nuclear generating facilities	(27)	46
Increase in electricity sales volume from Regulated – Hydroelectric generating facilities	9	13
Increase (decrease) in electricity sales volume from Unregulated generating facilities	15	(6)
Other changes in gross margin	35	14
	185	221
Higher realized earnings on nuclear fixed asset removal and nuclear waste management funds	32	5
Decrease in Pickering A return to service OM&A expense due to deferral of non-capital costs in 2005 as a rate regulated asset	65	124
Increase in nuclear maintenance and repairs	(25)	(42)
Increase in pension and other post employment benefit costs	(10)	(20)
Other net changes	10	13
Increase in income before income taxes and extraordinary item, excluding impairment of long-lived assets	**257**	**301**
Impairment of Pickering A generating station Units 2 and 3	(63)	(63)
Impairment of Lennox generating station	-	(202)
Income before income taxes and extraordinary item for the periods ended June 30, 2005	**141**	**91**

Earnings for the Three Months Ended June 30, 2005

Earnings for the three months ended June 30, 2005 were significantly impacted by an increase in gross margin from electricity sales due primarily to higher average sales prices compared to the same period in 2004. The increase in OPG's average sales price was due in part to higher average Ontario spot market prices resulting from record high temperatures in June 2005, which impacted revenue from OPG's unregulated generating assets. In addition, OPG's average sales price increased due to the introduction of regulated prices and other related regulatory changes effective April 1, 2005.

The increase in income during the second quarter of 2005 was also due to a decrease in operations, maintenance and administration ("OM&A") expenses resulting from the deferral of non-capital costs related to the Pickering A return to service project, commencing January 1, 2005, as required by a regulation pursuant to the *Electricity Restructuring Act, 2004.* In addition, higher realized earnings on the nuclear fixed asset removal and nuclear waste management funds also contributed to an increase in income during the second quarter of 2005 compared to the same period in 2004.

The favourable impact of these changes in earnings during the second quarter of 2005, was partly offset by higher nuclear maintenance and repairs related to continuing improvements in station reliability, and an increase in pension and other post employment benefit ("OPEB") costs primarily due to changes in economic assumptions.

In addition, the Company recorded an impairment loss of $63 million during the second quarter of 2005 related to Units 2 and 3 of the Pickering A nuclear generating station. Upon consideration of the scope of the work required to return these units to service, including the results of inspection programs, the risk and costs associated with this work, and OPG's focus on improving the performance of its other nuclear units, in August 2005, OPG's Board of Directors decided that while technically feasible, the return to service of these units was not justified on a commercial basis. As a result, OPG recorded the impairment loss representing the carrying value, including construction in progress, of these two units. The Company will have to assess the need to provide for additional charges as a result of this decision.

OPG adopted regulatory accounting for the rate regulated segments of its business, effective April 1, 2005. OPG accounts for income taxes relating to the rate regulated segments of the business using the taxes payable method, whereby future income tax assets and liabilities associated with these segments are no longer recognized. As a result, during the second quarter of 2005, OPG did not record a future tax expense for the rate regulated segments of $53 million, which would have been recorded had OPG accounted for income taxes for the regulated segments using the liability method. As part of this transition, OPG also eliminated a net future income tax asset of $74 million and recorded a corresponding one-time extraordinary loss.

Earnings for the Six Months Ended June 30, 2005

Earnings during the six months ended June 30, 2005 were favourably impacted by an increase in gross margin during the second quarter of 2005 due primarily to higher average sales prices. Higher electricity generation during the six months ended June 30, 2005 also contributed to an increase in gross margin compared to the same period last year. In addition, earnings were favourably impacted by the deferral of non-capital costs related to the Pickering A return to service project commencing in 2005.

Earnings for the six months ended June 30, 2005 were significantly impacted by the impairment loss on OPG's Lennox generating station of $202 million before tax, which was recorded during the first quarter of 2005. It was determined that the Lennox generating station, as a relatively high variable cost plant, would not be able to recover its fixed operating costs and carrying value from the wholesale electricity market in the future. OPG had initiated discussions with the Province, with the expectation of entering into a contractual arrangement for the recovery of the annual fixed operating costs and the carrying value of the Lennox generating station. OPG was subsequently advised by the Province during the first quarter of 2005 that it would continue to support OPG in negotiating an arrangement that would support the recovery of fixed operating costs, but that the Province would not support an arrangement that would allow for the recovery of the carrying value of the station. As a result of this change in circumstance, OPG recorded the impairment loss. OPG has since negotiated an arrangement with the Independent

Electricity System Operator ("IESO") to recover its fixed operating costs for a one-year period ending July 31, 2006. The arrangement with the IESO is subject to approval by the OEB.

Earnings for the six months ended June 30, 2005, were also unfavourably impacted by the impairment loss on the Pickering A nuclear generating station Units 2 and 3, higher nuclear maintenance and repairs related to continuing efforts to improve station reliability, and an increase in pension and OPEB costs primarily due to changes in economic assumptions.

Net income during the six months ended June 30, 2005 was unfavourably impacted by the one-time extraordinary loss related to the elimination of the net future income tax asset upon adoption of regulatory accounting effective April 1, 2005. This impact was largely offset by the reduction in future income tax expense during the second quarter of 2005 resulting from the application of the taxes payable method of accounting for the rate regulated segment.

Average Sales Prices

OPG's average sales prices by segment, net of the revenue limit rebate for the period April 1, 2005 to June 30, 2005, and net of the Market Power Mitigation Agreement up to the inception of rate regulation on April 1, 2005 are as follows:

	Three Months Ended June 30		**Six Months Ended June 30**	
(¢/kWh)	**2005**	**2004**	**2005**	**2004**
Regulated – Nuclear	**4.9**	4.0	**4.6**	4.1
Regulated – Hydroelectric	**3.9**[1]	4.2	**4.1**	4.2
Unregulated Generation	**5.3**[2]	4.1	**4.8**	4.3

1 During the three months ended June 30, 2005, electricity generation from stations in the Regulated – Hydroelectric segment received a fixed price of 3.3¢/kWh for generation less than 1,900 MWh in any hour, and the average spot electricity market price for generation above this level.

2 During the three months ended June 30, 2005, 85 per cent of the electricity generation from unregulated stations, excluding the Lennox generating station and other contract volumes, was subject to a revenue limit based on an average price of 4.7¢/kWh.

Electricity Generation

Total production during the three months ended June 30, 2005 from OPG's generating stations was 25.5 TWh compared to 24.7 TWh during the same period in 2004. The increase in generation was primarily a result of higher fossil-fuelled generation attributable to improved reliability from these stations and higher electricity demand primarily during the period of record high temperatures in June 2005. This increase was partly offset by the impact of the shutdown of Unit 4 at the Pickering A nuclear generating station for inspection and replacement of feeder pipes during the second quarter of 2005. The shutdown commenced on April 2, 2005 and the unit remained out of service for the duration of the quarter. The unit was returned to service on July 19, 2005. The increase in generation was also partly offset by a reduction in hydroelectric generation due to lower water levels and a decrease in generation from the Darlington nuclear generating station due to a higher number of planned outage days in the second quarter of 2005 compared to the same period in 2004.

For the six months ended June 30, 2005, total production from OPG's generating stations was 54.3 TWh compared to 52.9 for the same period in 2004. The increase in generation was primarily a result of higher fossil-fuelled generation in the second quarter of 2005, due to improved station performance and higher electricity demand, and higher nuclear generation. Improved performance at the Pickering B and Darlington nuclear generating stations more than offset the impact of the shutdown of Unit 4 of the Pickering A nuclear generating station. Hydroelectric generation was negatively impacted during the first six months of 2005 compared to the same period last year due to lower water levels.

OPG's results are impacted by changes in demand resulting from variations in seasonal weather conditions. The record high temperatures during June 2005 contributed to an increase in total demand for electricity in Ontario for the three and six month periods compared to the same periods in 2004.

The following table provides a comparison of heating and cooling degree days:

	Three Months Ended June 30		Six Months Ended June 30	
	2005	**2004**	**2005**	**2004**
Heating Degree Days [1]				
Period	**493**	520	**2,470**	2,474
Ten-year average	**517**	527	**2,387**	2,383
Cooling Degree Days [2]				
Period	**152**	39	**152**	39
Ten-year average	**85**	78	**85**	78

1 Heating Degree Days represent the aggregate of the differences between the average daily temperatures below 18°C and 18°C for each day during the period, as measured at Pearson International Airport in Toronto.

2 Cooling Degree Days represent the aggregate of the differences between the average daily temperatures above 18°C and 18°C for each day during the period, as measured at Pearson International Airport in Toronto.

Cash Flow from Operations

Cash flow provided by operating activities during the three months ended June 30, 2005 was $73 million compared to $146 million used in operating activities during the same period in 2004, an improvement of $219 million. Cash flow provided by operating activities during the six months ended June 30, 2005 was $373 million compared to $77 million during the same period in 2004, an improvement of $296 million. The favourable change in cash flow for both the three and six month periods was primarily due to higher revenue and earnings and lower rebates compared to the same periods in 2004.

Recent Developments

In April 2005, the Lakeview generating station was closed. In June 2005, the Ontario government announced the timing for the closure of OPG's remaining coal-fired stations. The Thunder Bay generating station, with 310 MW of generating capacity, is scheduled to be converted to gas-fired generation in 2007. The Atikokan generating station, with 215 MW of generating capacity, is scheduled to close by the end of 2007, following the conversion of the Thunder Bay units and necessary transmission upgrades. The Lambton generating station, with 1,975 MW of generating capacity, is scheduled to be closed by the end of 2007. The Nanticoke generating station, with 3,938 MW of generating capacity, is scheduled to have units closed through 2008, with the last unit scheduled to close in early 2009.

On May 2, 2005, OPG's Board of Directors announced the appointment of Jim Hankinson as President and CEO of Ontario Power Generation. Mr. Hankinson had been a Board member of OPG since December 2003. He replaced Acting President and CEO Richard Dicerni on May 13, 2005. Mr. Hankinson was President and CEO of New Brunswick Power Corporation from 1996 to 2002 and President and Chief Operating Officer of Canadian Pacific Limited from 1990 to 1995.

On May 25, 2005, staff representing striking Hydro One Society of Energy Professionals began picketing at various OPG generating facilities. On June 24, 2005, essential staff were prevented from reporting to work at the Nanticoke generating station resulting in the shutdown of six of the eight 500 MW units at the station. Following this event, OPG was forced to implement extraordinary measures and incurred unplanned costs in order to facilitate access of staff to safely operate its generating stations and to contribute to meeting the power needs of Ontario's electricity customers. OPG sought and was granted an injunction on June 28 restricting picketing by the Society of Energy Professionals, Hydro One Bargaining Unit at all its generating stations. OPG has also filed a claim for damages from the Society of Energy Professionals, Hydro One Bargaining Unit for losses caused by picketing at its sites.

OPG recently completed an assessment of the cost, schedule and risks related to the return to service of Units 2 and 3 at the Pickering A nuclear generating station. This included an assessment of the ability of these units to perform at an acceptable capability factor over the remaining 12 to 20 years of operations. This assessment incorporated recent findings from inspection programs with respect to feeder pipe and steam generator degradation mechanisms, and potential degradation of the calandria vault components, all of which could impact the future capability factor, operating costs and the life of the units. Upon consideration of the scope of the refurbishment work, the costs and the risks related to the return to service of these two units, and the Company's focus on improving the performance of its other nuclear units, OPG's Board of Directors decided in August 2005, that while technically feasible, the return to service of these units was not justified on a commercial basis. Accordingly, OPG recorded an impairment loss in the second quarter of 2005 related to the carrying amount of these two units including construction in progress, which was $63 million at June 30, 2005.

VISION, CORE BUSINESS AND STRATEGY

OPG's mandate is to cost effectively produce electricity from its diversified generation assets, while operating in a safe, open and environmentally responsible manner. To achieve this mandate, OPG is concentrating its efforts on further improving generating asset performance through production efficiencies and increased reliability; adding to its generating capacity; effective cost management; and strengthening corporate governance.

Improving the Performance of Generating Assets

OPG's portfolio of generation assets is diversified in terms of technology, fuel type and dispatch flexibility. Production costs are generally competitive with other generators in Ontario and the U.S. northeast and midwest, although higher than generators in Manitoba and Quebec which have a large supply of low cost hydroelectric generation.

OPG continues to make investments to increase the long-term reliability and performance of its nuclear and hydroelectric generating stations, while maintaining the productive capability of the coal-fired fossil generating stations until their closure.

Nuclear Generating Assets

Nuclear generating stations provide baseload electricity generation as they have low marginal operating costs. OPG's nuclear strategy is to operate the Darlington and Pickering stations in an efficient and cost effective manner while undertaking prudent investments to improve the reliability and predictability of these assets. OPG conducts comprehensive inspection and testing programs to ascertain the physical condition of its nuclear generation stations in order to improve the reliability and predictability of the nuclear stations. OPG is implementing steam generator inspection and rehabilitation programs; feeder pipe integrity projects; pressure tube remediation programs such as Spacer Location and Relocation (SLAR); and initiatives aimed at reducing maintenance backlogs.

Hydroelectric Generating Assets

OPG's hydroelectric stations operate primarily for baseload purposes and provide a reliable, low-cost source of renewable energy that is air emission-free. OPG's hydroelectric strategy is to optimize production from its 64 stations as well as to expand, develop, and improve its hydroelectric capacity on its own or in partnership with external parties. Sir Adam Beck 2 - Unit 14, was returned to service in April 2005. This marked the successful completion of the Sir Adam Beck 2 Rehabilitation and Runner Upgrade Project, which began in 1996. The station's original turbines and major electrical equipment were replaced with more efficient current technology, adding 194 MW of capacity. Through capital reinvestment, station automation, efficiency improvements and effective plant maintenance, OPG has increased the productive capacity of its hydroelectric plants, extended their service lives and lowered their operating and maintenance costs. This reinvestment program is continuing, and includes an accelerated runner upgrade program aimed at increasing hydroelectric capacity by an additional 110 to 120 MW between 2005 and 2012.

Fossil-Fuelled Generating Assets

Fossil-fuelled stations provide a flexible source of energy and operate as baseload, intermediate and peaking facilities depending on the characteristics of the particular stations. In Ontario, production from OPG's fossil plants is contingent upon electricity demand, price and the availability of nuclear, hydroelectric, and other non-OPG generators. As a consequence of the Government's intention to close OPG's coal facilities, the Company's strategy is to maintain the productive capability of these facilities while operating them in an environmentally responsible manner. While capital investments required to maintain production and meet environmental objectives will continue, no new major investments are planned. As well, the expenditure profile of the coal plants has shifted from a 'replace' to a 'repair' strategy. In particular, maintenance programs have been modified to address the impacts of increased unit starts and manoeuvring of units, in part due to the role that the fossil-fuelled plants perform as intermediate and peaking facilities.

Adding to OPG Generating Capacity

OPG's strategy, with Shareholder consent, is to continue to pursue initiatives that increase the Company's electricity generation capacity. These initiatives include the upcoming return to service of Unit 1 at the Pickering A nuclear station and initiatives to increase the capacity of hydroelectric stations.

Pickering A Unit 1 Return to Service

Major construction for the return to service of Unit 1 at the Pickering A nuclear generating station commenced in July 2004. As of June 30, 2005, the fieldwork execution was approximately 95 per cent complete. Total cumulative expenditures to the end of June 30, 2005 were $948 million.

The major construction phase of the project was completed in July 2005, with the removal of Unit 1 from the guaranteed shutdown state. OPG is now conducting the commissioning phase, which is expected to be completed over a three month period before the unit is declared in commercial service in the fall of 2005.

Although OPG has completed the major construction phase, the schedule and cost to complete the project were impacted by the discovery of feeder pipe thinning in areas not previously identified. This resulted in the need to perform additional inspections and the replacement of one feeder pipe, which was not included in the original scope of the project and the cost estimate. In addition, feeder issues resulted in the shutdown of Unit 4 at the Pickering A nuclear generating station. Resources were diverted from Unit 1 to address the Unit 4 feeder issue and to complete other outage work, which also contributed to the extension of the Unit 1 project schedule. The costs related to the feeder inspection and replacement program and the schedule extension were approximately $20 million. The projected costs to complete the project are approximately $1.0 billion, excluding the impact on costs of the feeder inspection and replacement, and the diversion of resources to Unit 4.

Costs and schedule to complete the project could continue to be impacted by the discovery of additional repairs or refurbishment work that may be identified during the course of the commissioning phase.

Niagara Tunnel

In June 2004, OPG announced and the Government endorsed the decision to proceed with a new water diversion tunnel that will increase the amount of water flowing to existing turbines at the Sir Adam Beck generating stations in Niagara. This tunnel will allow the Beck generating facilities to more effectively utilize available water and is expected to increase annual generation on average by about 1.6 TWh. OPG is undertaking an open and competitive process to select a design-build contractor for the 10.5 km tunnel. Three pre-qualified companies submitted detailed design-build proposals in May 2005. Construction activities are expected to start in the fall of 2005.

Portlands Energy Centre

OPG entered into a partnership with TransCanada Energy Ltd. ("TransCanada"), called Portlands Energy Centre L.P. ("PEC"), to pursue the development of a 550 MW gas-fired, combined cycle station on the site of the former R.L. Hearn generating station, near downtown Toronto. The generating station would help to meet the growing energy needs of Toronto's downtown core.

PEC proceeded under the Environmental Screening Process pursuant to the *Guide to Environmental Assessment Requirements for Electricity Projects*. Further to that process, decisions in favour of the PEC project proceeding, subject to certain conditions, were made by both the Director of the Environmental Assessment and Approvals Branch, Ministry of the Environment ("MOE") and the Minister of the Environment. Further to direction of the MOE, PEC issued a Statement of Completion pursuant to this process on April 1, 2005.

In September 2004, the Province issued a Request for Proposals for 2,500 MW of New Clean Generation and Demand Side Management Projects. PEC submitted a bid under this process, but was not among the six bids that were selected in April and June 2005. PEC continues to seek opportunities to develop the project under future Government procurement processes.

BUSINESS SEGMENTS

Prior to the introduction of rate regulation, OPG had two reportable business segments: Generation and Energy Marketing. A separate category, Non-Energy and Other, included revenue and certain costs not allocated to the business segments. With the introduction of rate regulation, OPG changed the definition of business segments with effect from April 1, 2005 in recognition of the different economic characteristics of the Company's operations. The business segments are: Regulated – Nuclear, Regulated – Hydroelectric, and Unregulated Generation. In addition, OPG continues to report a separate category, Other, which includes trading activities that previously comprised the Energy Marketing business segment, and revenues and certain costs neither attributable nor allocated to the business segments.

OPG has entered into various energy and related sales contracts with its customers to hedge commodity price exposure to changes in electricity prices associated with the spot market for electricity in Ontario. Contracts that are designated as hedges of OPG's generation revenues are included with electricity production revenues in each segment up to March 31, 2005 and in the Unregulated Generation segment after that date. Gains or losses on these hedging transactions are recognized in revenue over the term of the contract when the underlying transaction occurs.

Regulated – Nuclear Segment

OPG's Regulated – Nuclear business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering A and B, and Darlington nuclear generating stations.

OPG's Regulated – Nuclear business segment includes revenue under the terms of a lease arrangement with Bruce Power related to the Bruce nuclear generating stations. The arrangement includes lease revenue, interest income and revenue from engineering analysis and design, technical and other services. The Regulated – Nuclear business segment also includes revenue earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control/reactive support. These earnings are included in the Regulated - Nuclear business segment since they were included in determining the regulated price for production from the nuclear facilities.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its baseload hydroelectric generating stations. The business segment includes electricity generated by the Sir Adam Beck 1, 2 and Pump Generating Station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. The Regulated – Hydroelectric business segment also includes ancillary revenues earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control.

Unregulated Generation Segment

OPG's Unregulated Generation business segment operates in Ontario, generating and selling electricity from its fossil-fuelled generating stations and from the hydroelectric generating stations not included in the Regulated – Hydroelectric segment. The Unregulated Generation business segment also includes ancillary revenues, and revenues from other services.

Other

OPG earns revenue from its joint venture share of the Brighton Beach Power Limited Partnership ("Brighton Beach") related to an energy conversion agreement between Brighton Beach and Coral Energy Canada Inc. ("Coral"). In addition, the Other category includes revenue from real estate rentals.

In addition, the revenue and expenses related to OPG's trading and other non-hedging activities are included in the Other category. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in other revenue as gains or losses.

KEY GENERATION PERFORMANCE INDICATORS

OPG's revenue is primarily dependent upon the quantity of electricity produced by its generating stations and the price at which that electricity is sold. OPG's electricity production is dependent on the availability of its generating stations to deliver energy and on electricity demand. OPG evaluates the performance of generating stations using a number of key performance indicators, which vary depending on the generation technology. OPG has included the following two key indicators in the Discussion of Operating Results section.

- Nuclear Unit Capability Factor – the amount of energy that the unit(s) generated over a period of time, adjusted for external energy losses such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation.

- Fossil-fuelled and Hydroelectric Equivalent Forced Outage Rate (EFOR) – an index of the reliability of the generating unit measured by the ratio of time a generating unit is forced out of service, including any forced deratings, compared to the amount of time the generating unit was available to operate.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

This section summarizes OPG's key results by segment for the three months and six months ended June 30, 2005 and 2004. Although the regulations pursuant to the *Electricity Restructuring Act, 2004* became effective commencing April 1, 2005, results for the periods prior to the second quarter of 2005 have been reclassified according to the new business segment definitions. The prior period results from OPG's nuclear and hydroelectric generating stations that are now regulated have been reclassified into the Regulated – Nuclear and Regulated – Hydroelectric segments for comparative purposes. Similarly, results from OPG's unregulated generating stations have been reclassified into the Unregulated Generation segment. Accordingly, revenues reflect spot market prices received for electricity sales net of the Market Power Mitigation Agreement rebate up to the inception of rate regulation on April 1, 2005.

The operating results for the period prior to rate regulation reflect a significantly different economic environment from that introduced by rate regulation.

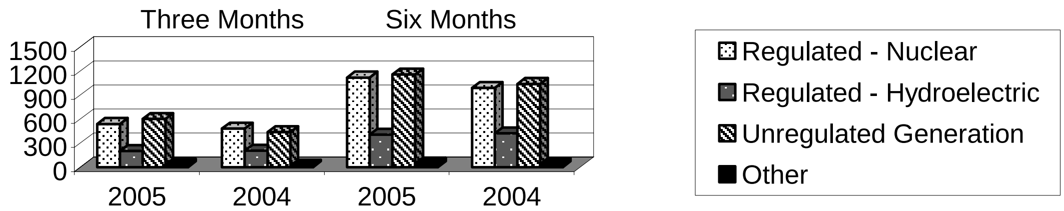
The following table provides a summary of revenue, earnings and operating statistics by business segment:

	Three Months Ended June 30		**Six Months Ended June 30**	
(millions of dollars)	**2005**	**2004**	**2005**	**2004**
Revenue, net of Market Power Mitigation Agreement rebate and revenue limit rebate:				
Regulated – Nuclear	**540**	481	**1,120**	991
Regulated – Hydroelectric	**202**	207	**407**	421
Unregulated Generation	**603**	437	**1,157**	1,040
Other	**28**	16	**47**	39
	1,373	1,141	**2,731**	2,491
Income (loss) before interest, income taxes and extraordinary item				
Regulated – Nuclear	**(99)**	(134)	**(115)**	(226)
Regulated – Hydroelectric	**94**	101	**206**	227
Unregulated Generation	**181**	36	**84**	155
Other	**12**	(11)	**10**	(11)
	188	(8)	**185**	145
Electricity production[1] (TWh)				
Regulated – Nuclear	**9.4**	10.0	**21.4**	20.4
Regulated – Hydroelectric	**5.0**	4.7	**9.6**	9.3
Unregulated Generation – Hydroelectric	**4.4**	5.3	**8.2**	9.5
Unregulated Generation – Fossil-fuelled	**6.7**	4.7	**15.1**	13.7
Total electricity generation	**25.5**	24.7	**54.3**	52.9
Nuclear unit capability factor [2] (per cent)				
Darlington	**80.4**	86.3	**87.1**	86.0
Pickering A	**1.9**	54.2	**50.6**	74.0
Pickering B	**72.9**	62.9	**78.6**	67.1
Equivalent forced outage rate (per cent)				
Regulated – Hydroelectric	**0.5**	3.3	**0.6**	2.1
Unregulated Generation – Hydroelectric	**1.5**	1.4	**1.3**	1.4
Unregulated Generation – Fossil-fuelled	**16.8**	31.6	**16.1**	27.6

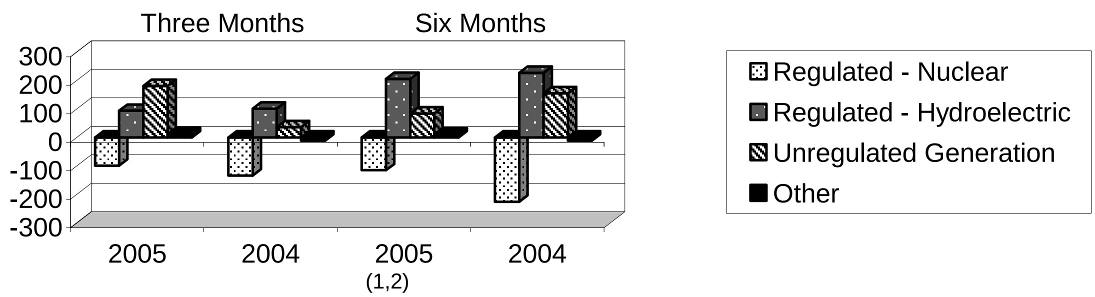
1 Electricity generation is presented in accordance with OPG's business segments, with the exception of the Unregulated Generation segment, for which generation from hydroelectric and fossil-fuelled generating stations is shown separately.

2 Capability factors by industry definition exclude grid-related unavailability.

Revenue, Net of Market Power Mitigation Agreement Rebate and Revenue Limit Rebate by Segment
(millions of dollars)

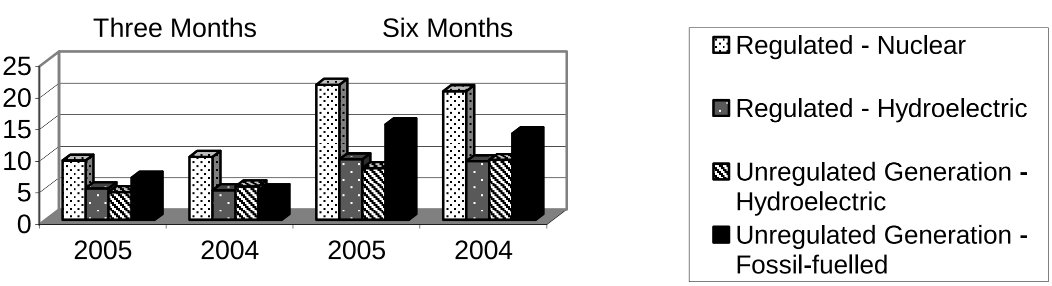


Income (loss) Before Interest, Income Taxes and Extraordinary Item by Segment
(millions of dollars)



(1) During the second quarter of 2005, OPG recorded a $63 million impairment loss on the Pickering A generating station Units 2 and 3.
(2) During the first quarter of 2005, OPG recorded a $202 million impairment loss related to its Lennox generating station.

Electricity Production
(TWh)



Regulated – Nuclear Segment

(millions of dollars)	Three Months Ended June 30 2005	Three Months Ended June 30 2004	Six Months Ended June 30 2005	Six Months Ended June 30 2004
Revenue, net of Market Power Mitigation Agreement rebate	**540**	481	**1,120**	991
Fuel expense	**25**	24	**54**	54
Gross margin	**515**	457	**1,066**	937
Operations, maintenance and administration				
Expenses excluding Pickering A return to service	**441**	397	**859**	796
Pickering A return to service	**-**	65	**-**	124
Depreciation and amortization	**94**	93	**186**	186
Accretion on fixed asset removal and nuclear waste management liabilities	**117**	112	**234**	223
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(112)**	(80)	**(183)**	(178)
Property and capital taxes	**11**	4	**22**	12
Operating income	**(36)**	(134)	**(52)**	(226)
Impairment loss	**63**	-	**63**	-
(Loss) income before interest, income taxes and extraordinary item	**(99)**	(134)	**(115)**	(226)

Impairment of Long-Lived Assets – Pickering A Generating Station Units 2 and 3

The Company recorded an impairment loss of $63 million in the second quarter of 2005 related to the carrying amount of Pickering nuclear generating station Units 2 and 3, including construction in progress. OPG expects to recover the amounts recorded in the deferral account relating to non-capital costs incurred after January 1, 2005 associated with the return to service of Units 2 and 3. As at June 30, 2005, the deferral account relating to Units 2 and 3 was $10 million.

As a result of the decision not to proceed with the return to service of these two units, OPG will have to assess the prospect of providing for additional charges, including the cost associated with preparing the units for safe storage, any impacts on cost estimates for asset retirement obligation, any excess inventory, and any other additional exit costs. These potential additional charges are not specifically determinable at this time, however a detailed assessment of these associated costs will be completed during the remainder of 2005. Such charges may have a significant impact on operating results in future periods.

Revenue

(millions of dollars)	Three Months Ended June 30 2005	Three Months Ended June 30 2004	Six Months Ended June 30 2005	Six Months Ended June 30 2004
Spot market sales, net of hedging instruments	**-**	467	**662**	1,048
Market Power Mitigation Agreement rebate	**-**	(64)	**(160)**	(206)
Regulated generation sales	**461**	-	**461**	-
Other	**79**	78	**157**	149
Total revenue	**540**	481	**1,120**	991

Regulated – Nuclear revenue was $540 million for the three months ended June 30, 2005 compared to $481 million during the same period in 2004. The increase in revenue was primarily due to higher sales prices related to the introduction of regulated rates effective April 1, 2005, which exceeded OPG's average spot market price net of the Market Power Mitigation Agreement rebate for the same period in 2004. This increase in revenue was partially offset by the impact of lower electricity generation during the second quarter of 2005 compared to the same period last year.

Regulated – Nuclear revenue was $1,120 million for the six months ended June 30, 2005 compared to $991 million during the same period in 2004. The increase in revenue was primarily related to the higher electricity sales prices in the second quarter of 2005 related to the introduction of rate regulation and the impact of higher electricity generation in 2005, despite lower volumes in the second quarter.

Electricity Prices

Since market opening on May 1, 2002, and prior to April 1, 2005, OPG was required under its generation licence issued by the OEB to comply with prescribed market power mitigation measures, including a rebate mechanism. Under the Market Power Mitigation Agreement, OPG had been required to pay a rebate to the IESO equal to the excess, if any, of the average hourly spot energy price over 3.8¢/kWh for the amount of energy sales subject to the rebate mechanism for those generating stations that OPG continues to control. The IESO passed the rebate on to consumers. The amount of energy generated by OPG that was subject to the rebate mechanism was approximately 80 TWh on an annual basis.

Electricity generation from stations in the Regulated – Nuclear segment received a fixed price of 4.95¢/kWh during the three months ended June 30, 2005. OPG's average sales price for the six months ended June 30, 2005 was 4.6¢/kWh, after taking into account the regulated rate for the second quarter and OPG's average spot market sales price, net of the Market Power Mitigation Agreement rebate for the first quarter. In 2004, OPG's average sales prices, after taking into account the Market Power Mitigation Agreement rebate, were 4.0¢/kWh and 4.1¢/kWh for the three and six months ended June 30, 2004, respectively.

Volume

Electricity sales volume from the generating assets in the Regulated – Nuclear segment for the three months ended June 30, 2005 was 9.4 TWh compared to 10.0 TWh for the same period in 2004. Unit 4 at the Pickering A nuclear generating station was shut down on April 2, 2005 for inspection of feeder pipes and remained out of service for the duration of the quarter. This resulted in a second quarter unit capability factor of 1.9 per cent. The unit was returned to service on July 19, 2005, after replacing two feeder pipes. In addition, generation from the Darlington nuclear generating station decreased during the second quarter of 2005 compared to the same period in 2004 due to a higher number of planned outage days. The impact of these outages on generation volume was partly offset by significant improvements in reliability at the Pickering B nuclear generating station, where fewer unplanned outage days resulted in a higher unit capability factor.

Total nuclear generation for the six months ended June 30, 2005 increased to 21.4 TWh from 20.4 TWh for the same period in 2004. The increase in volume was due to improved performance at the Pickering B and Darlington nuclear generating stations compared to the same period in 2004, both of which experienced fewer unplanned outage days. The improved performance at Pickering B and Darlington more than offset the impact of the Pickering A Unit 4 shutdown.

Fuel Expense

Fuel expense for the three months ended June 30, 2005 was $25 million compared to $24 million in 2004. Fuel expense for the six months ended June 30, 2005 and June 30, 2004 was $54 million. Fuel expense for the nuclear generating stations was only marginally impacted by the changes in generation volumes in 2005 compared to 2004 due to the low marginal cost nature of nuclear generation.

Operations, Maintenance and Administration

OM&A expenses, excluding those related to the Pickering A return to service initiative, were $441 million for the three months ended June 30, 2005 compared to $397 million for the same period in 2004, an increase of $44 million. As part of OPG's objective to improve the performance of its nuclear generating stations, the Company has committed additional resources in an effort to maximize the operating availability and reliability of these stations. OM&A expenses for nuclear maintenance and repairs increased by $25 million compared to the same period in 2004. These expenditures related to improvement projects and ongoing maintenance costs to address plant condition and regulatory requirements. Pension and OPEB expenses increased by $7 million compared to the same period in 2004, primarily the result of changes in economic assumptions related to discount rates.

OM&A expenses, excluding those related to the Pickering A return to service initiative, were $859 million for the six months ended June 30, 2005 compared to $796 million for the same period in 2004, an increase of $63 million. OM&A expenses for nuclear maintenance and repairs increased by $42 million compared to the same period in 2004, related to plant condition and performance improvements, and regulatory requirements. Pension and OPEB costs increased by $15 million during the six months ended June 30, 2005 compared to the same period in 2004, primarily due to changes in economic assumptions.

Pickering A Return to Service

Effective January 1, 2005, in accordance with a regulation pursuant to the *Electricity Restructuring Act, 2004*, OPG established a balance sheet deferral account for non-capital costs associated with the return to service of Pickering A nuclear generating station units. Consequently, non-capital costs related to the Pickering A return to service initiative were excluded from OM&A during the three and six months ended June 30, 2005. Had these expenditures not been deferred, an expense of $88 million would have been recognized in the second quarter of 2005 compared to $65 million for the same period last year. During the six months ended June 30, 2005, an expense of $189 million would have been recognized compared to $124 million during the same period in 2004. The increase in expenditures was primarily due to a higher level of construction activity in 2005 related to the Unit 1 return to service.

The deferred costs will be charged to operations in subsequent periods, in accordance with the recovery of these amounts through rates charged to future customers. This is consistent with one of the objectives of rate regulation, which is to ensure that present customers are not burdened with costs incurred for the benefit of future customers, and with generally accepted accounting principles in that the financial effects of regulation can lead to assets and liabilities that would not otherwise be recognized by a non-rate-regulated entity.

Depreciation and Amortization

Depreciation and amortization expense for the three months ended June 30, 2005 was $94 million compared to $93 million in the 2004 period. Depreciation and amortization expense for the six months ended June 30, 2005 and June 30, 2004 was $186 million.

Accretion

OPG records the present value of its future costs for fixed asset removal and nuclear waste management as a long-term liability. This liability is discussed in Note 7 to the unaudited interim consolidated financial statements as at and for the three and six months ended June 30, 2005. Accretion expense reflects the change in the present value of this liability since the end of the prior period. This expense is impacted by factors such as any changes in the estimate of the amount of the future liability for fixed asset removal and nuclear waste management, any changes to the discount rate used to determine the present value, and the change in the present value due to the passage of time.

Accretion expense for the three months ended June 30, 2005 was $117 million compared with $112 million for the same period in 2004. Accretion expense for the six months ended June 30, 2005 was $234 million compared with $223 million for the same period last year. The increase in the accretion expense was due to the higher liability base compared to last year as a result of the increase in the present value of the liability due to the passage of time.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

OPG is responsible for the ongoing long-term management and disposal of radioactive wastes and used fuel resulting from operations and future decommissioning of its nuclear generating stations. OPG's obligations relate to the Pickering and Darlington nuclear plants that are operated by OPG, as well as the Bruce nuclear plant that is leased by OPG to Bruce Power.

Pursuant to the Ontario Nuclear Funds Agreement ("ONFA") between OPG and the Province of Ontario, OPG established the Used Fuel Fund and the Decommissioning Fund (together the "Nuclear Funds"). The Used Fuel Fund is intended to fund future expenditures associated with high-level nuclear waste disposal, while the Decommissioning Fund was established to fund future expenditures associated with nuclear fixed asset removal and the disposal of low and intermediate level waste related thereto. OPG maintains the Nuclear Funds in third party custodial accounts that are segregated from the rest of OPG's assets.

Assets in the Nuclear Funds are invested in fixed income and equity securities, which OPG records as long-term investments and accounts for at their amortized cost value. Therefore, gains and losses are recognized only upon the sale of an underlying security. As such, there may be unrealized gains and losses associated with the Nuclear Funds which OPG has not recognized. The balance of the Nuclear Funds, on an amortized cost basis, as at June 30, 2005 was $6,376 million compared to $5,976 million as at December 31, 2004.

Under ONFA, the Province guarantees the annual rate of return in the Used Fuel Fund at 3.25 per cent plus the change in the Ontario Consumer Price Index ("committed return") over the long term. OPG recognizes the committed return on the Used Fuel Fund and includes it in earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the assets, which includes realized and unrealized returns, is due to or from the Province. Since OPG accounts for the investments in the Nuclear Funds on an amortized cost basis, the amount due to or due from the Province recorded in the consolidated financial statements is the difference between the committed return and the actual return based on realized returns only. At June 30, 2005, the Used Fuel Fund included an amount due from the Province of $1 million (December 31, 2004 – due to the Province of $4 million). If the investments in the Used Fuel Fund were accounted for at fair market value in the interim consolidated financial statements, at June 30, 2005, there would be an amount due to the Province of $213 million (December 31, 2004 – $156 million). In addition, the Province is entitled to any surplus in the Used Fuel Fund, subject to a threshold over-funded ratio of 110 per cent compared to the value of the associated liabilities.

Under ONFA, the Decommissioning Fund has a long-term target rate of return of 5.75 per cent per annum. OPG bears the risk and liability for cost estimate increases and fund earnings associated with the Decommissioning Fund. At June 30, 2005, based on the estimate of costs to complete under the current approved ONFA Reference Plan (the 1999 Reference Plan), the Decommissioning Fund was fully funded on a market value basis and almost fully funded on an amortized cost basis. In the event that realized gains result in overfunding of the Decommissioning Fund, the earnings recognized on the investments in the fund would be limited, through a charge to the fund with a corresponding payable to the Province, such that the amortized cost balance of the fund would equal the cost estimate of the liability based on the 1999 Reference Plan. These realized gains may be recognized in subsequent periods provided the fund balance declines below the then currently approved cost estimate.

At June 30, 2005, the Decommissioning Fund assets value at amortized cost was approximately $3,973 million with a market value of approximately $4,313 million, the difference representing net unrealized gains totalling approximately $340 million. Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the approved ONFA Reference Plan, are at least 120 per cent funded, OPG may direct up to 50 per cent of the surplus over 120 per cent as a contribution to the Used Fuel Fund, and the Ontario Electricity Financial Corporation ("OEFC") is entitled to a distribution of an identical amount. Any overfunding of the liability is payable to the Province on termination of the fund. If the investments in the Decommissioning Fund were accounted for at fair market value in the interim consolidated financial statements at June 30, 2005, and the Decommissioning Fund was terminated under the ONFA, there would be an amount due to the Province of $323 million (December 31, 2004 – $249 million).

Earnings on the Nuclear Funds for the three months ended June 30, 2005 were $112 million compared to $80 million for the same period last year, an increase of $32 million. The higher earnings in 2005 were primarily a result of an increase in Used Fuel Fund returns, due to a higher Ontario Consumer Price Index during the second quarter of 2005, compared to the same period in 2004, and a larger asset base during the period due to growth through a combination of earnings and contributions.

Earnings on the Nuclear Funds for the six months ended June 30, 2005 were $183 million compared to $178 million for the same period last year, an increase of $5 million. The higher earnings on the Used Fuel Fund during the second quarter were largely offset by lower earnings in the Decommissioning Fund in the first quarter of 2005 compared to the same period last year. The higher earnings during the first quarter of 2004 were a result of additional realized returns in the fund due to the sale of investments related to asset mix rebalancing.

Regulated – Hydroelectric Segment

	Three Months Ended June 30		**Six Months Ended June 30**	
(millions of dollars)	**2005**	**2004**	**2005**	**2004**
Revenue, net of Market Power Mitigation Agreement rebate and variance account	**202**	207	**407**	421
Fuel expense	**69**	64	**122**	115
Gross margin	**133**	143	**285**	306
Operations, maintenance and administration	**18**	18	**36**	35
Depreciation and amortization	**16**	18	**34**	33
Property and capital taxes	**5**	6	**9**	11
Income before interest, income taxes and extraordinary item	**94**	101	**206**	227

Revenue

(millions of dollars)	**Three Months Ended June 30** **2005**	**2004**	**Six Months Ended June 30** **2005**	**2004**
Spot market sales, net of hedging instruments	**-**	232	**260**	497
Market Power Mitigation Agreement rebate	**-**	(37)	**(65)**	(106)
Regulated generation sales[1]	**195**	-	**195**	-
Interim variance account	**(4)**	-	**(4)**	-
Other	**11**	12	**21**	30
Total revenue	**202**	207	**407**	421

1 Regulated generation sales includes revenue of $69 million that OPG received at the Ontario spot market price for generation over 1,900 MWh in any hour in periods after April 1, 2005.

Regulated – Hydroelectric revenue was $202 million for the three months ended June 30, 2005 compared to $207 million during the same period in 2004. The decrease in revenue was primarily due to lower sales prices, related to the introduction of regulated rates effective April 1, 2005. The average of the fixed regulated price and the spot market price for generation in excess of 1,900 MWh in any hour, for the second quarter of 2005, was less than OPG's average electricity spot market price net of the Market Power Mitigation Agreement rebate during the same period in 2004. Higher electricity generation partially offset the impact of the decrease in revenue related to the lower average sales prices.

Regulated – Hydroelectric revenue for the six months ended June 30, 2005 was $407 million compared to $421 million during the same period in 2004. The decrease in revenue was primarily related to the lower prices in the second quarter of 2005 compared to 2004, partially offset by higher electricity generation in 2005.

Electricity Prices

During the three months ended June 30, 2005, the average electricity sales price for the Regulated – Hydroelectric segment was 3.9¢/kWh. The average sales price is based on the fixed price of 3.3¢/kWh for generation less than 1,900 MWh in any hour, and the average spot electricity market price for generation above this level. The average price for the six months ended June 30, 2005, was 4.1¢/kWh, after taking into account the regulated rate for the second quarter and OPG's average spot market sales price net of the Market Power Mitigation Agreement rebate for the first quarter. After taking into account the Market Power Mitigation Agreement rebate, the average spot market sales price for the three and six months ended June 30, 2004 was 4.2¢/kWh.

Volume

Electricity sales volume for the three months ended June 30, 2005 was 5.0 TWh compared to 4.7 TWh for the same period in 2004, of which 1.0 TWh in 2005 related to production levels above 1,900 MWh in any hour. Electricity sales volume for the six months ended June 30, 2005 was 9.6 TWh compared to 9.3 TWh for the same period in 2004. The increase in sales volume was due to increased water flows on the Niagara and St. Lawrence.

Interim Variance Account

OPG is required under the regulations pursuant to the *Electricity Restructuring Act, 2004* to establish a variance account to capture the impact of differences in hydroelectric electricity production due to differences between forecast and actual water conditions. OPG recorded a liability as at June 30, 2005 of $4 million, reflecting water conditions that were favourable to those forecasted for the second quarter of 2005.

Fuel Expense

Fuel expense for the three months ended June 30, 2005 was $69 million compared to $64 million in 2004. Fuel expense for the six months ended June 30, 2005 was $122 million compared to $115 million in 2004. OPG pays charges to the Province and the OEFC on gross revenue derived from the annual generation of electricity from its hydroelectric generating assets. The gross revenue charge ("GRC") includes a fixed percentage charge applied to the annual hydroelectric generation derived from stations located on provincial Crown lands, in addition to graduated rate charges applicable to all hydroelectric stations. GRC costs are included in fuel expense. Fuel expense for 2005 was higher compared to 2004 due to higher generation volumes.

Operations, Maintenance and Administration

OM&A expenses were $18 million for the three months ended June 30, 2005 and June 30, 2004. OM&A expenses were $36 million for the six months ended June 30, 2005 compared to $35 million for the same period in 2004.

Depreciation and Amortization

Depreciation and amortization expense for the three months ended June 30, 2005 was $16 million compared to $18 million for the same period in 2004. Depreciation and amortization expense for the six months ended June 30, 2005 was $34 million compared to $33 million in the 2004 period.

Unregulated Generation Segment

	Three Months Ended June 30		**Six Months Ended June 30**	
(millions of dollars)	**2005**	**2004**	**2005**	**2004**
Revenue, net of Market Power Mitigation Agreement rebate and revenue limit	**603**	437	**1,157**	1,040
Fuel expense	**195**	154	**423**	411
Gross margin	**408**	283	**734**	629
Operations, maintenance and administration	**142**	140	**279**	277
Depreciation and amortization	**74**	76	**148**	154
Accretion on fixed asset removal	**3**	2	**5**	4
Property and capital taxes	**8**	13	**16**	23
Restructuring	**-**	16	**-**	16
Operating income	**181**	36	**286**	155
Impairment loss	**-**	-	**(202)**	-
Income before interest, income taxes and extraordinary item	**181**	36	**84**	155

Impairment of Long-Lived Assets – Lennox Generating Station

The Lennox generating station has available generating capacity in excess of 2,000 MW, is available to provide operating reserve, and has dual fuel capability with natural gas and oil. The Lennox generating station has annual fixed operating costs of about $50 million. Since the formation of OPG in 1999, revenue earned from electricity generated at the Lennox station was generally not sufficient to cover the fixed operating costs and annual depreciation charge related to the station. However, up until 2004, OPG expected that in the future, demand for new electricity supply requirements in Ontario would require the development of a capacity market or higher market prices sufficient for new entrants to cover their costs and provide a return on investment. As a result, revenues associated with the Lennox station were expected to be sufficient to cover all costs, including a recovery of the carrying value.

In 2004, the Government issued a "Request for Information/Request for Proposal for 2,500 MW of New Clean Generation and Demand Side Management Projects" under which new generators would be allowed to recover fixed costs and an agreed upon rate of return on investment through contractual arrangements. By recovering these costs through contractual arrangements with the Ontario Power Authority, new entrants would need to recover only fuel and other variable operating costs from the wholesale market. These contracts are expected to result in lower than anticipated future revenue from the wholesale electricity market.

As a relatively high cost plant, the Lennox generating station will not be able to recover its fixed operating costs and the carrying value from the wholesale market in the future. Given these factors, and the precedent established under the Request for Information/Request for Proposal for 2,500 MW, OPG had initiated discussions with the Province, with the intention of entering into a contractual arrangement for the recovery of the annual fixed operating costs of about $50 million and the carrying value of the Lennox station over its remaining estimated useful life of $17 million per year.

OPG followed up on the discussions with the Province concerning the Lennox generating station situation by engaging in discussions with the IESO during the first quarter of 2005. OPG expected that it would be able to negotiate an arrangement that would provide for the recovery of all costs. Subsequently, OPG was advised by the Province that it would continue to support OPG in the negotiations with the IESO regarding the recovery of fixed operating costs, but that the Province would not support an arrangement that would allow for the recovery of costs related to the carrying value of the Lennox station. As a result of the change in circumstance, OPG recorded an impairment loss of $202 million during the first quarter of 2005, which was the amount of the carrying value of the generating station before the impairment loss. OPG has since negotiated an arrangement with the IESO to recover its fixed operating costs for a one-year period ending July 31, 2006. The arrangement with the IESO is subject to approval by the OEB.

Revenue

	Three Months Ended June 30		**Six Months Ended June 30**	
(millions of dollars)	**2005**	**2004**	**2005**	**2004**
Spot market sales, net of hedging instruments	**710**	516	**1,423**	1,318
Market Power Mitigation Agreement rebate	**-**	(107)	**(187)**	(337)
Revenue limit rebate	**(141)**	-	**(141)**	-
Other	**34**	28	**62**	59
Total revenue	**603**	437	**1,157**	1,040

Unregulated Generation revenue was $603 million for the three months ended June 30, 2005 compared to $437 million during the same period in 2004. The increase in revenue was primarily related to higher average sales prices and higher generation of electricity in the second quarter of 2005 compared to the same period in 2004.

Unregulated Generation revenue for the six months ended June 30, 2005 was $1,157 million compared to $1,040 million during the same period in 2004. The increase in revenue was primarily due to higher average prices during the six months ended June 30, 2005 and higher generation of electricity compared to the same period in 2004.

Electricity Prices

Eighty-five per cent of the generation output from OPG's unregulated generation assets, excluding the Lennox generating station, TRO volumes and forward sales as of January 1, 2005, are subject to a revenue limit based on an average price of $47.00/MWh during the period April 1, 2005 to April 30, 2006. Prior to April 1, 2005, OPG received the average electricity spot market sales price, but revenue was reduced by the Market Power Mitigation Agreement rebate.

The average sales price for the three months ended June 30, 2005 was 5.3¢/kWh, after taking into account the impact of the revenue limit rebate. The average price for the six months ended June 30, 2005 was 4.8¢/kWh, after taking into account the Market Power Mitigation Agreement rebate for the first quarter of 2005, and the revenue limit rebate. The average spot market sales prices for the three and six months ended June 30, 2004 were 4.1¢/kWh and 4.3¢/kWh respectively, net of the Market Power Mitigation Agreement rebate.

The higher prices during the second quarter and the six month periods in 2005 compared to the same periods in 2004 were due to higher average spot market sales prices during 2005 compared to 2004 and the replacement of the Market Power Mitigation Agreement rebate with the revenue limit effective April 1, 2005. Higher average spot prices in 2005 reflected the impact of higher demand influenced by the record high temperatures in June 2005.

Volume

Electricity sales volume for the three months ended June 30, 2005 was 11.1 TWh compared to 10.0 TWh for the same period in 2004. The increase in volume was due to higher generation from the fossil-fuelled generating stations to meet increased demand in Ontario during the period of record high temperatures in June 2005. The improved reliability of the fossil-fuelled generating stations during the second quarter of 2005 enabled OPG to generate electricity in response to this increased demand. The increase was partly offset by lower volumes from the unregulated hydroelectric facilities due to lower water levels, especially in the Ottawa and northeast regions.

Electricity sales volume for the six months ended June 30, 2005 was 23.3 TWh compared to 23.2 TWh for the same period in 2004. The increase in generation from the fossil-fuelled generating stations during the second quarter of 2005 compared to the same period in 2004, was largely offset by the impact of lower hydroelectric generation due to lower water levels during the six months ended June 30, 2005 compared to the same period last year.

Fuel Expense

Fuel expense for the three months ended June 30, 2005 was $195 million compared to $154 million in 2004. Fuel expense for the six months ended June 30, 2005 was $423 million compared to $411 million in 2004. Fuel expense for the Unregulated Generation segment includes the cost of fossil fuels and charges on gross revenue derived from the hydroelectric generating stations. The increase in fuel expense during the 2005 period was primarily due to the higher production from the fossil-fuelled generating stations.

Operations, Maintenance and Administration

OM&A expenses were $142 million for the three months ended June 30, 2005 compared to $140 million for the same period in 2004. OM&A expenses were $279 million for the six months ended June 30, 2005 compared to $277 million for the same period in 2004.

Depreciation and Amortization

Depreciation and amortization expense for the three months ended June 30, 2005 was $74 million compared to $76 million during the same period in 2004. Depreciation and amortization expense for the six months ended June 30, 2005 was $148 million compared to $154 million during the same period last year.

Other

(millions of dollars)	Three Months Ended June 30 2005	Three Months Ended June 30 2004	Six Months Ended June 30 2005	Six Months Ended June 30 2004
Revenue	**28**	16	**47**	39
Operations, maintenance and administration	**15**	13	**29**	25
Depreciation and amortization	**8**	7	**17**	13
Property and capital taxes	**(7)**	7	**(9)**	12
(Loss) income before interest and income taxes and extraordinary item	**12**	(11)	**10**	(11)

Revenue

Non-Energy revenue was $28 million during the three months ended June 30, 2005 compared to $16 million for the same period in 2004. Non-Energy revenue was $47 million during the six months ended June 30, 2005 compared to $39 million for the same period in 2004. The increases of $12 million and $8 million in the 2005 periods compared to the same periods last year were primarily related to revenue earned from OPG's 50 per cent partnership interest in Brighton Beach, which became operational in July 2004.

Trading revenue for the three months ended June 30, 2005 was $6 million compared to $9 million during the same period in 2004. Trading revenue for the six months ended June 30, 2005 was $8 million compared to $24 million during the same period in 2004. The decreases of $3 million during the three months ended June 30, 2005 and $16 million during the six months ended June 30, 2005 compared to the same periods last year were primarily due to constrained liquidity in the Ontario electricity market, which reduced opportunities for trading.

Interconnected purchases and sales (including those to be physically settled) and mark-to-market gains and losses (realized and unrealized) on energy trading contracts are disclosed on a net basis in the consolidated statements of income. On a gross basis, revenue and power purchases for the three months ended June 30, 2005 would have increased by $45 million (three months ended June 30, 2004 – $56 million), with no impact on net income. Revenue and power purchases for the six months ended June 30, 2005 would have increased by $100 million (six months ended June 30, 2004 – $95 million), with no impact on net income.

Net Interest Expense

Net interest expense for the three months ended June 30, 2005 was $47 million compared to net interest expense of $45 million during the same period in 2004. Net interest expense for the six months ended June 30, 2005 was $94 million compared to net interest expense of $90 million during the same period in 2004.

Income Tax

Commencing April 1, 2005, OPG accounts for income taxes relating to the rate regulated segments of the business using the taxes payable method, whereby only the amount of taxes that are payable for the current taxation year are recorded. Accordingly, OPG will not be recognizing future income taxes relating to the rate regulated segments of the business on the basis that these income taxes are expected to be recovered in the regulated rates charged to future customers. For all other operations, the liability method of tax accounting will be followed. Under the liability method, future tax assets and liabilities are determined based on differences between the accounting and tax basis of assets and liabilities and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse.

Income tax expense for the three months ended June 30, 2005 was $4 million compared to income tax recovery of $12 million during the same period in 2004. Income tax recovery for the six months ended June 30, 2005 was $8 million compared to income tax expense of $32 million during the same period in 2004. During the second quarter of 2005, the income tax expense was $53 million lower than what would otherwise have been recorded, due to the application of the taxes payable method for the regulated segments.

As a result of the adoption of rate regulated accounting for the rate regulated segments on April 1, 2005, OPG eliminated the net future income tax asset balance of $74 million relating to the rate regulated segments and recognized the amount as a one-time extraordinary loss in determining net income.

STATEMENTS OF CASH FLOWS

Three Months ended June 30	2005	2004	Explanation
Cash and cash equivalents, beginning of period	**135**	419	
Cash flow provided by (used in):			
Operating activities	**73**	(146)	Increase in cash from operating activities primarily due to higher sales revenue and earnings in 2005 compared to the same period in 2004.
Investing activities	**(196)**	(127)	Increase in cash used in investing activities due to treatment of non-capital expenses related to the Pickering A return to service project as a regulatory asset in 2005, partially offset by the decrease in investment in fixed assets.
Financing activities	**399**	3	Increase in cash from financing activities in 2005 due to the issuance of long-term debt.
Net increase (decrease)	**276**	(270)	
Cash and cash equivalents, end of period	**411**	149	

Six Months ended June 30	2005	2004	Explanation
Cash and cash equivalents, beginning of period	**2**	286	
Cash flow provided by (used in):			
Operating activities	**373**	77	Increase in cash from operating activities primarily due to higher sales revenue and earnings in 2005 compared to 2004.
Investing activities	**(431)**	(223)	Increase in cash used in investing activities due primarily to treatment of non-capital expenses related to the Pickering A return to service project as a regulatory asset in 2005.
Financing activities	**467**	9	Increase in cash from financing activities in 2005 due to the issuance of long-term debt, partially offset by a net repayment of short-term notes.
Net increase (decrease)	**409**	(137)	
Cash and cash equivalents, end of period	**411**	149	

CAPITAL RESOURCES AND FUNDING OBLIGATIONS

OPG is in a capital-intensive business that requires continued investment in plant and technologies to improve operating efficiencies, increase generating capacity of its existing stations and to maintain and improve service, reliability, safety and environmental performance. Capital expenditures during the three months ended June 30, 2005 were $106 million compared with $127 million during the same period in 2004. Capital expenditures during the six months ended June 30, 2005 were $240 million compared with $223 million during the same period in 2004. OPG's anticipated capital expenditures for 2005 are approximately $600 million. New potential supply initiatives, including the Niagara Tunnel project, would require additional capital expenditures and funding in 2005, if approved. The amount of the expenditures could vary significantly, depending on OPG's future role in the Ontario electricity market.

OPG made contributions of $39 million to the pension plan during the three months ended June 30, 2005 compared to $38 million during the same period in 2004. OPG made contributions of $78 million to the pension plan during the six months ended June 30, 2005 compared to $76 million during the same period in 2004.

As required under the ONFA, OPG made contributions to the nuclear fixed asset removal and nuclear waste management funds of $113 million during the second quarters of 2005 and 2004, and $114 million during the first quarters of 2005 and 2004.

OPG made Market Power Mitigation Agreement rebate payments of $386 million during the three months ended June 30, 2005 and $338 million during the same period in 2004. OPG made Market Power Mitigation Agreement rebate payments of $606 million during the six months ended June 30, 2005 and $652 million during the same period in 2004. Since the Ontario market opened to competition on May 1, 2002, OPG has paid rebates totalling $3.7 billion up to June 30, 2005, resulting in a significant unfavourable impact on OPG's liquidity. The Market Power Mitigation Agreement rebates are paid in arrears, with the final payment due August 10, 2005.

LIQUIDITY

OPG's current 364-day term $1,000 million revolving committed bank credit facility was renewed on May 24, 2005. The new facility is divided into two tranches – a $500 million 364-day term tranche maturing May 23, 2006, and a $500 million three year term tranche maturing May 23, 2008. The total credit facility will continue to be used primarily as support for notes issued under OPG's commercial paper program. As at June 30, 2005, OPG had no borrowings outstanding under this commercial paper program (December 31, 2004 – $26 million). As at June 30, 2005, OPG had no other outstanding borrowing under this facility.

OPG also maintains $26 million (December 31, 2004 – $26 million) in short-term uncommitted overdraft facilities as well as $213 million (December 31, 2004 – $200 million) of short-term uncommitted credit facilities, which support the issuance of Letters of Credit. OPG uses Letters of Credit to support the supplementary pension plan, and is required to post the Letters of Credit as collateral with Local Distribution Companies ("LDCs") as prescribed by the Ontario Energy Board's ("OEB") Retail Settlement Code. At June 30, 2005, there were approximately $158 million (December 31, 2004 – $155 million) of Letters of Credit issued for the supplementary pension plan and collateral requirements to the LDCs.

In March 2005, the Company reached an agreement with the OEFC to obtain additional financing up to $600 million. The financing was required to meet a forecast operating cash shortfall related to the implementation of rate regulation, including the continuing rebate obligation under the revenue limit. In April 2005, $400 million was drawn under this facility with a seven-year term. In accordance with the agreement with the OEFC, the remaining $200 million of additional financing is available until March 31, 2006. OPG will draw the remaining $200 million during early 2006, subject to its requirements for additional financing.

At June 30, 2005, OPG's long-term credit rating is BBB+ by Standard & Poor's and A (low) by Dominion Bond Rating Service (DBRS). In May 2005, following a review of the new regulatory framework that OPG will operate within, DBRS changed the trend on OPG's unsecured debt from negative to stable and confirmed the rating on OPG's commercial paper at R-1 (low). Maintaining an investment grade credit rating is essential for corporate liquidity, future capital market access.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies, including the impact of future accounting pronouncements, are outlined in Note 3 to the consolidated financial statements as at and for the year ended December 31, 2004. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's consolidated financial statements, the likelihood that materially different amounts would be reported under varied conditions and estimates and the impact of changes in certain conditions or assumptions, are highlighted on pages 19 to 22 of the MD&A for the year ended December 31, 2004. With the exception of rate regulated accounting, there have not been any significant changes in OPG's critical accounting policies during the six months ended June 30, 2005.

Rate Regulated Accounting

A regulation made pursuant to the *Electricity Restructuring Act, 2004* prescribes that OPG's nuclear and baseload hydroelectric facilities receive regulated prices for their output. Under this regulation, OPG is required to establish a deferral account in connection with non-capital costs incurred on or after January 1, 2005 that are associated with the return to service of units at the Pickering A nuclear generating station. As at June 30, 2005, the deferral account was $191 million, consisting of non-capital costs of $179 million relating to Unit 1, and $10 million relating to Units 2 and 3, and interest, accreted at the average cost of debt of 6.0 per cent, in the amount of $2 million. Upon OPG becoming regulated by the OEB in 2008, the OEB is directed by the regulation to ensure that OPG recovers any balance in the deferral account through rates charged to future customers on a straight-line basis, over a period not to exceed 15 years. OPG will commence the amortization of the deferral account associated with Unit 1 of the Pickering A nuclear generating station when the unit enters commercial service later in 2005.

In addition, under the regulation, OPG is required to establish a variance account for certain unforeseen costs incurred on or after April 1, 2005 associated with a number of predefined circumstances. Under the terms of the regulation, the OEB is directed to ensure that OPG recovers those costs, which have been prudently incurred and accurately recorded, through rates charged to future customers over a period not to exceed three years.

With the commencement of rate regulation for OPG's baseload hydroelectric and nuclear facilities on April 1, 2005, OPG recorded an extraordinary loss of $74 million resulting from the elimination of the net future income tax asset, and revised its definition of business segments.

Business Segments

Prior to April 1, 2005, OPG had two reportable business segments: Generation and Energy Marketing. A separate category, Other, included revenue and certain expenses that were not allocated to the business segments. With the introduction of rate regulation, OPG changed the definition of its reportable business segments in order to remain compliant with the Canadian Institute of Chartered Accountants ("CICA") handbook, section 1701 – Segment Disclosure. OPG reports its results on the basis of these new segments beginning April 1, 2005 and has reclassified prior period amounts accordingly.

Income Taxes

OPG is exempt from tax under the *Income Tax Act* (Canada). However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income and capital taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), and are modified by regulations made under the *Electricity Act, 1998*.

OPG's operations are complex and the computation of the provision for income taxes involves interpretation of the various tax statutes and regulations. The *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) have a large body of technical interpretations and case law to help determine the Company's filing position. However, the *Electricity Act, 1998*, is relatively new and apart from the regulations, has no other interpretive body. It was therefore necessary for OPG to take certain filing positions in calculating the amount of the income tax provision. These filing positions may be challenged on audit and possibly disallowed, resulting in a potential significant increase in OPG's tax provision upon reassessment. Although management believes that it has adequately provided for income taxes based on all information currently available, there is uncertainty given how recently the legislation was introduced.

Commencing April 1, 2005, OPG accounts for income taxes related to the rate regulated segments of the business in accordance with paragraphs 102 to 104 inclusive of the CICA handbook, section 3465 – Income Taxes. Accordingly, OPG will not be recognizing future income taxes related to the rate regulated segments of the business to the extent that these income taxes are expected to be recovered in the regulated rates charged to future customers.

For all other operations, OPG uses the liability method and provides future income taxes for income tax temporary differences. The process involves an estimate of OPG's actual current tax liability and an assessment of the Company's future income taxes as a result of temporary differences arising from the difference between the tax basis of an asset or liability and its carrying value in the balance sheet. In addition, OPG has to assess whether the future tax assets can be realized and to the extent that recovery is not considered likely, a valuation allowance must be established. Judgement is required in determining the provision for income taxes, future income tax assets and liabilities and any related valuation allowance. To the extent a valuation allowance is created or revised, current period earnings will be affected.

RISK MANAGEMENT

OPG's portfolio of generation assets and its electricity trading and marketing operations are subject to inherent risks, including financial, operational, and strategic risks as discussed on page 23 to 27 of the MD&A as at and for the year ended December 31, 2004. To manage these risks, OPG's Board of Directors and management have implemented an integrated enterprise-wide risk management framework for the governance, identification, measurement, monitoring and reporting of risk across all of OPG and its business operations. Implementation and coordination of corporate-wide risk management activities are undertaken through a centralized risk management group, separate and independent from operational management. Risk information from the business units is independently assessed and aggregated by the risk management group, and is reported by the Chief Risk Officer to the Audit and Risk Committee of the Board of Directors on a quarterly basis. Risk based processes are incorporated into strategic and financial planning to ensure the Company's sustainability and achievement of its stated objectives.

While OPG believes it is pursuing appropriate risk management strategies, there can be no assurance that one or more of the risks outlined or other risk factors will not have a material adverse impact on OPG. In particular, the *Electricity Restructuring Act, 2004* and related regulations, the imposition of a revenue limit on the non-regulated assets excluding the Lennox generating station and volumes related to existing contracts, and changes in the future mandate of OPG in the Ontario electricity marketplace could have a material impact on OPG.

Financial Risk

Commodity Price Risk

Commodity price risk is the risk that changes in the market price of electricity or of the fuels used to produce electricity that will adversely impact OPG's earnings and cash flow from operations. To manage this risk, the Company seeks to maintain a balance between the commodity price risk inherent in its electricity production and plant fuel portfolios to the extent that trading liquidity in the relevant commodities markets provides the opportunity to do so in an economically justified manner. To manage the input risk, OPG has a fuel hedging program. In addition to fixed price contracts for fossil and nuclear fuels, OPG periodically employs derivative instruments to hedge its fuel price risk.

With the recent implementation of reforms to the Ontario electricity market, the amount of expected electricity production that OPG previously had hedged through regulatory commitments and forward electricity transactions has changed materially. The Market Power Mitigation Agreement was replaced with a regulated price for baseload hydroelectric and nuclear generation. Eighty-five per cent of the remaining unregulated OPG electricity generation, excluding generation from the Lennox generating station and volumes relating to existing contracts, is subject to a revenue limit of $47.00/MWh, in place from April 1, 2005 to April 30, 2006.

The percentages of OPG's expected generation, emission requirements and fuel requirements hedged are shown below:

	2005	**2006**	**2007**
Estimated generation output hedged [1]	92%	70%	59%
Estimated fuel requirements hedged [2]	99%	89%	81%
Estimated nitric oxide (NO) emission requirement hedged [3]	100%	90%	61%
Estimated sulphur dioxide (SO_2) emission requirement hedged [3]	100%	100%	100%

[1] Represents the portion of megawatt-hours of expected future generation production, including power purchases, for which the Company has sales commitments and contracts including the obligations under the transition rate option contracts, regulated price for baseload hydroelectric and nuclear generation, and revenue limit for non-prescribed assets.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and fossil year-end inventory target) from all types of facilities (fossil, nuclear and hydroelectric) for which OPG has entered into some form of contractual arrangements or obligations in order to secure either the expected availability and/or price of fuel and/or fuel related services. Excess fuel in inventories in a given year is attributed to the next year for the purpose of measuring hedge ratios. Since production from hydroelectric facilities is primarily influenced by expected weather and weather patterns, fuel hedge ratios for hydroelectric facilities are assumed to be 100 per cent.

[3] Represents the approximate portion of megawatt-hours of expected fossil production for which OPG has purchased, been allocated or granted emission allowances and emission reduction credits to meet OPG's obligations under Ontario Environmental Regulation 397/01.

Open trading positions are subject to measurement against Value at Risk (VaR) limits. VaR utilization ranged between $1.4 million and $2.0 million during the three months ended June 30, 2005, compared to $0.5 million and $0.8 million during the three months ended June 30, 2004. VaR utilization ranged between $1.2 million and $2.0 million during the six months ended June 30, 2005, compared to $0.5 million and $1.0 million during the six months ended June 30, 2004. VaR utilization is within the risk tolerance of the Company, under approved VaR limits.

Trading liquidity continues to be constrained in Ontario and interconnected markets due to broader energy market fundamentals. In addition, the revenue limit of $47.00/MWh limits customer exposure to electricity spot market prices and further limits trading liquidity in the period to April 30, 2006.

Credit Risk

Credit risk is the financial risk of non-performance by contractual counterparties. Credit risk excludes any operational risk resulting from a third party failing to deliver a product or service as expected. OPG derives revenue from several other sources including the sale of energy products and financial risk management products to third parties. However, the majority of OPG revenues are derived from sales through the IESO administered spot market.

Credit exposure to the IESO fluctuates based on a blend of regulated and non-regulated rates as well as generated volume and is reduced each month upon settlement of the accounts. Credit exposure to the IESO peaked at $894 million during the six months ended June 30, 2005 and at $901 million during the six months ended June 30, 2004.

OPG's management believes that the IESO is an acceptable credit risk due to its primary role in the Ontario market. The IESO manages its own credit risk and its ability to pay generators by mandating that all registered IESO spot market participants meet specific IESO standards for creditworthiness and collateralization. Additionally, in the event of an IESO participant default, each market participant shares the exposure pro rata. Given OPG's position in the marketplace, the Company would bear approximately 35 per cent of the exposure, residual of collateral and recovery.

OPG also monitors and reports its credit exposure with counterparties. OPG's management believes these are within acceptable limits and does not anticipate any material effect on its results of operations or cash flows arising from potential defaults.

The following table provides information on credit risk from energy sales and trading activities as at June 30, 2005:

			Potential Exposure for Largest Counterparties	
Credit Rating [1]	**Number of Counterparties [2]**	**Potential Exposure [3]**	**Number of Counterparties**	**Counterparty Exposure**
		(millions of dollars)		*(millions of dollars)*
AAA to AA-	39	18	1	7
A+ to A-	46	54	2	29
BBB+ to BBB-	89	24	1	4
BB+ to BB-	30	107	6	104
Below BB-	31	2	-	-
Subtotal	235	205	10	144
IESO	1	570	1	570
Total	236	775	11	714

1 Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through guarantees and letters of credit or other security.
2 OPG Counterparties are defined by each Master Agreement.
3 Potential exposure is OPG's assessment of the maximum exposure over the life of each transaction at 95 per cent confidence.

For all counterparties, OPG's contracts allow for active collateral management to mitigate credit exposures. The contracts provide for a counterparty to post performance guarantees in excess of the established threshold. OPG may employ such guarantees as a result of market price changes or upon the occurrence of credit-related events. The threshold amount represents credit limits established in accordance with the corporate credit policy. Inability to post collateral is sufficient cause to terminate a contract and liquidate all positions.

Operational Risk

Generation Risk

OPG is exposed to the financial impacts of uncertain output from its generating units. The amount of electricity generated by OPG is affected by fuel supply, equipment malfunction, maintenance requirements, and regulatory and environmental constraints. To mitigate earnings volatility due to generation risk, OPG enters into multiple short-term and long-term fuel supply agreements and long-term water use agreements, manages fuel supply inventories, and follows industry practices for maintenance and outage scheduling. In addition, OPG ensures regulatory requirements are met, particularly with respect to licensing of its nuclear facilities, and manages environmental constraints utilizing programs such as emission reduction credits.

OPG is exposed to considerable technology risk around the aging of the nuclear fleet. Technology risks that could lead to significant impacts on the production capability or operating life of these assets are not fully predictable and OPG attempts to identify and mitigate these risks through ongoing management review and assessments, internal audits and from experience of nuclear units around the world. OPG has undertaken an ongoing life cycle management program to assess the condition of major components of the nuclear units, including steam generators, fuel channels and feeder pipes, and address the active degradation mechanisms associated with these major components. Current predictions for unit end of life are based on the end of life predictions for the fuel channels.

Thinning of the carbon steel feeder pipes used to transport the hot pressurized water in the reactor to the steam generators is an industry-wide issue. Thinning of feeder pipes occurs to varying degrees at all of OPG's reactors. While this condition affects all of OPG's nuclear generating stations, it is most significant at the Darlington nuclear generating station. Mitigation options are under development by OPG which may extend feeder pipe life, reduce the thinning rate, and improve the capability to replace feeders, where required. Recent wall thickness measurements of feeders removed from Pickering A Unit 1 and inspections in Units 1 and 4 have indicated that the location of the thinning is different than at Darlington, and the degree of thinning is greater than originally expected. Future inspections will be required to confirm the thinning rate at Pickering A, and to determine the need for future feeder pipe replacements. Pickering B feeder pipes have been found to be less affected by thinning than those at Darlington and Pickering A.

Cracking of feeder pipes has been experienced at two CANDU plants located outside Ontario. At those plants, the affected sections of pipe were replaced and the units were returned to service. OPG has not experienced any feeder pipe cracking at any of its nuclear facilities but is carrying out inspections during regularly planned outages. The scale of these inspections has been increased in response to these external events to address the concern that the risk of cracking may be increasing in OPG's units. Recent results from one of the external plants indicate a worsening of the cracking situation, which may require a further increase in the scale of inspections at OPG's plants to determine whether the experience elsewhere will also impact OPG's plant condition. OPG is also participating in research and development with other CANDU operators to better understand the degradation mechanisms.

The Pickering A reactors are unique among the CANDU fleet in that the reactor is contained within an air-filled concrete enclosure called the "calandria vault". The environment is potentially corrosive to carbon steel components contained within the calandria vault structure, particularly when the atmosphere is humid. Significant degradation of the carbon steel components occurred early in life. Maintenance was carried out during the 1980s and early 1990s to mitigate the degradation and repair some of the degraded components. Equipment was added to maintain a dry vault atmosphere and thereby significantly reduce the risk of corrosion. There is limited information to determine the extent to which mitigation efforts have been successful. Further inspections are being planned.

Late in 2004, as a result of steam generator inspection activities, OPG noted the existence of a new degradation mechanism on one of the Pickering A steam generators from Unit 1. This mechanism, intergranular attack ("IGA"), is a corrosion phenomenon where the material is chemically attacked during unusual chemical conditions, and previously has not been seen in OPG's Pickering and Darlington nuclear generating stations. In combination with other degradation mechanisms, this mechanism could impact the life of the steam generator. The scope of inspections on Pickering A steam generators was expanded to determine the extent of this degradation mechanism. Inspections at Unit 1 of the Pickering A nuclear generating station have been completed and, while IGA was found to be present in some tubes, the steam generators are fit for service. The inspection of Pickering A Unit 2 confirmed extensive IGA. The inspection of Pickering A Unit 3 was partially completed and severe denting was confirmed. IGA was not observed on Pickering A Unit 4.

In 2004, inspections of Pickering A Unit 2 uncovered a single crack originating in the outer diameter of the steam generator tubing. This was the first crack observed in any of the Pickering A and B steam generator tubes and resulted in an increase in the scope of inspection for all Pickering A and B steam generators. Recent inspections on Pickering A Unit 1 and Pickering B Unit 5 have not uncovered any further cracks. However, recent inspections of Pickering A Unit 4 have confirmed a single 81 per cent through-wall crack. Operating units observed to have cracked tubes would likely require a shortened operating interval in the range of one year before inspection. Tubes which cannot be demonstrated to be fit for service can be removed from service. This will increase outage duration and costs.

Regulatory Risk

Through a regulation passed pursuant to the *Electricity Restructuring Act, 2004*, OPG receives regulated prices for its baseload hydroelectric and nuclear facilities from April 1, 2005. These prices are expected to remain in effect until at least March 31, 2008, or until such time that the Ontario Energy Board ("OEB") establishes new regulated prices. If there are changes to the fundamental assumptions on which these regulated prices were developed, the Province may amend these initial prices. Any such changes pose a risk that the return on equity factored into the existing prices could be reduced. Equally, to the extent that costs incremental to those included in the price determination process occur and no such amendments are made, these costs may be borne by OPG and not recovered through rates charged to future customers. These costs may be necessary to maintain the reliability and safety of OPG's regulated generating assets.

The regulation also directed OPG to establish a variance account for costs incurred on or after April 1, 2005 that are associated with certain unforeseen circumstances, and to establish a deferral account for Pickering A return to service non-capital costs incurred on or after January 1, 2005. The accuracy and prudency of any variance account balances that OPG records as a regulatory asset or liability must be demonstrated by OPG to the OEB once it establishes new regulated prices in 2008. Regulatory risk arises given the possibility of the OEB not approving such costs. In the event that some of these costs are disallowed by the OEB at a future date, the amounts disallowed would be reflected in results of operations in the period that the OEB decision occurs.

CONTINUOUS DISCLOSURE

Summary of Quarterly Results

The following tables set out certain unaudited interim consolidated financial statement information for each of the eight most recent quarters ended June 30, 2005. The information has been derived from OPG's unaudited interim consolidated financial statements that, in management's opinion, have been prepared on a basis consistent with the audited consolidated financial statements. These operating results are not necessarily indicative of results for any future period.

	2004 Quarters Ended		**2005 Quarters Ended**	
(millions of dollars)	**September 30**	**December 31**	**March 31**	**June 30**
Revenue after Market Power Mitigation Agreement rebate and revenue limit rebate	**1,212**	**1,215**	**1,358**	**1,373**
Net (loss) income	**(15)**	**34**	**(38)**	**63**
Net (loss) income per share	**$(0.06)**	**$0.13**	**$(0.15)**	**$0.25**

	2003 Quarters Ended		**2004 Quarters Ended**	
(millions of dollars)	**September 30**	**December 31**	**March 31**	**June 30**
Revenue after Market Power Mitigation Agreement rebate	1,224	1,228	1,350	1,141
Net income (loss)	34	(606)[1]	64	(41)
Net income (loss) per share	$0.13	$(2.36)	$0.25	$(0.16)

[1] OPG recorded an impairment loss on the coal-fired generating stations of $473 million after tax ($576 million before tax) due to the expected early shutdown of the coal-fired generating stations.

Off-Balance Sheet Arrangements

Securitization

In October 2003, OPG completed a revolving securitization agreement with an independent trust. Under the securitization agreement, OPG sold an undivided co-ownership interest in certain current and future accounts receivable generated in the normal course of business. The amount of the co-ownership interest sold is removed from the balance sheet with each revolving securitization. OPG also retains an undivided co-ownership interest in the receivables sold to the trust. This retained interest is accounted for at cost on OPG's balance sheet. The independent trust is not controlled by OPG, nor is OPG the primary beneficiary of the trust's expected losses. As such, the results of the trust are not consolidated.

The securitization provides OPG with an opportunity to obtain an alternative source of cost-effective funding. For the three months ended June 30, 2005, the average all-in cost of funds was 2.9 per cent and the pre-tax charges on sales to the trust were $2 million. For the six months ended June 30, 2005, the average all-in cost of funds was 2.9 per cent and the pre-tax charges on sales to the trust were $4 million. The initial net cash proceeds from this transaction of $300 million were used by OPG in the operation of its business. Termination of the arrangement, which in the absence of early termination, occurs in August 2006, would likely require OPG to pursue alternative liquidity arrangements to meet the ongoing operations of the business.

Guarantees

As part of normal business, OPG and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees, stand-by Letters of Credit and surety bonds.

OPG has provided limited guarantees in connection with its share of the Brighton Beach financing, whereby it is responsible for contributing its share of equity related to cost overruns associated with the construction of the generating station. As at June 30, 2005, OPG met its obligations for contributing its share of equity related to cost overruns. As Brighton Beach commenced commercial operation in July 2004, any cost overruns are now primarily limited to settlement of construction liens registered by some contractors associated with the construction project. Brighton Beach arranged an independent third party review of the claims and is now actively negotiating final settlement of these liens.

Derivative Instruments

The majority of OPG's derivative instruments are treated as hedges, with gains or losses recognized upon settlement when the underlying transactions occur. OPG holds financial commodity derivatives primarily to hedge the commodity price exposure associated with changes in the price of electricity. Foreign exchange derivative instruments are used to hedge the exposure to anticipated US dollar denominated purchases. When such a derivative instrument ceases to exist or when designation of a hedging relationship is terminated, any associated deferred gains or losses are carried forward to be recognized in income in the same period as the corresponding gains or losses associated with the hedged item. When a hedged item ceases to exist, any associated deferred gains or losses are recognized in the current period's consolidated statement of income. The deferred loss on electricity derivative instruments treated as hedges was $101 million as at June 30, 2005, compared to a deferred loss of $71 million as at December 31, 2004. See Note 9 to the unaudited interim consolidated financial statements for more information.

All contracts not designated as hedges are recorded as assets or liabilities at fair value with changes in fair value recorded in Other revenue.

SUPPLEMENTAL EARNINGS MEASURES

In addition to providing net income in accordance with Canadian generally accepted accounting principles, OPG's Management Discussion and Analysis, financial statements for the three and six months ended June 30, 2005 and 2004 and the notes thereto, present non-GAAP financial measures. These financial measures do not have standard definitions prescribed by Canadian generally accepted accounting principles ("Canadian GAAP") and therefore, may not be comparable to similar measures disclosed by other companies. OPG utilizes these measures in making operating decisions and assessing its performance. Readers of the MD&A, financial statements and notes thereto utilize these measures in assessing the Company's financial performance from ongoing operations. These non-GAAP financial measures have not been presented as an alternative to net income in accordance with Canadian GAAP as an indicator of operating performance. The definitions of the non-GAAP financial measures are as follows:

(1) **Gross margin** is defined as revenue less Market Power Mitigation Agreement and revenue limit rebates and fuel expense.

(2) **Restructuring** expenses are defined as costs incurred to implement a fundamental and material change to the operating and/or management structures of the Company. Restructuring expenses may include severance costs, termination benefits and related pension and OPEB expenses, professional fees, travel costs and other incremental costs directly associated with the restructuring activities.

(3) **Operating income** is defined as earnings before long-lived asset impairment charges, net interest expense, income taxes and extraordinary item.

The statement of income provides a reconciliation of operating income to Canadian GAAP net income.

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CONSOLIDATED STATEMENTS OF INCOME (LOSS) (UNAUDITED)

(millions of dollars except where noted)	**Three Months Ended June 30 2005**	**Three Months Ended June 30 2004**	**Six Months Ended June 30 2005**	**Six Months Ended June 30 2004**
Revenue				
Revenue before Market Power Mitigation Agreement and revenue limit rebates	**1,514**	1,349	**3,284**	3,140
Market Power Mitigation Agreement rebate *(note 13)*	**-**	(208)	**(412)**	(649)
Revenue limit rebate *(note 14)*	**(141)**	-	**(141)**	-
	1,373	1,141	**2,731**	2,491
Fuel expense	**289**	242	**599**	580
Gross margin	**1,084**	899	**2,132**	1,911
Expenses				
Operations, maintenance and administration	**616**	633	**1,203**	1,257
Depreciation and amortization *(note 4)*	**192**	194	**385**	386
Accretion on fixed asset removal and nuclear waste management liabilities	**120**	114	**239**	227
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(112)**	(80)	**(183)**	(178)
Property and capital taxes	**17**	30	**38**	58
Restructuring	**-**	16	**-**	16
	833	907	**1,682**	1,766
Operating income	**251**	(8)	**450**	145
Impairment of long-lived assets *(note 4)*	**63**	-	**265**	-
Income (loss) before interest, income taxes and extraordinary item	**188**	(8)	**185**	145
Net interest expense	**47**	45	**94**	90
Income (loss) before income taxes and extraordinary item	**141**	(53)	**91**	55
Income tax (recoveries) expenses				
Current	**7**	(2)	**14**	6
Future *(note 2)*	**(3)**	(10)	**(22)**	26
	4	(12)	**(8)**	32
Income (loss) before extraordinary item	**137**	(41)	**99**	23
Extraordinary item *(note 2)*	**74**	-	**74**	-
Net income (loss)	**63**	(41)	**25**	23
Basic and diluted income (loss) per common share *(dollars)*	**0.25**	(0.16)	**0.10**	0.09
Common shares outstanding *(millions)*	256.3	256.3	256.3	256.3

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (UNAUDITED)

Six Months Ended June 30 *(millions of dollars)*	**2005**	**2004**
(Deficit) retained earnings, beginning of period	**(105)**	(147)
Net income (loss)	**25**	23
(Deficit), end of period	**(80)**	(124)

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(millions of dollars)	Three Months Ended June 30 2005	Three Months Ended June 30 2004	Six Months Ended June 30 2005	Six Months Ended June 30 2004
Operating activities				
Net income (loss)	**63**	(41)	**25**	23
Adjust for non-cash items:				
Depreciation and amortization	**192**	194	**385**	386
Accretion on fixed asset removal and nuclear waste management liabilities	**120**	114	**239**	227
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(112)**	(80)	**(183)**	(178)
Pension cost	**28**	23	**56**	46
OPEB and supplementary pension	**46**	41	**91**	81
Future income taxes	**(3)**	(10)	**(22)**	26
Transition rate option contracts	**(9)**	(9)	**(18)**	(26)
Provision for restructuring	**-**	16	**-**	16
Mark-to-market on energy contracts	**2**	4	**4**	5
Provision for used nuclear fuel	**6**	6	**13**	15
Impairment of long-lived assets	**63**	-	**265**	-
Extraordinary item	**74**	-	**74**	-
Other	**1**	2	**-**	6
	471	260	**929**	627
Contributions to nuclear fixed asset removal and nuclear waste management funds	**(113)**	(113)	**(227)**	(227)
Expenditures on fixed asset removal and nuclear waste management	**(25)**	(18)	**(39)**	(31)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management	**4**	8	**10**	8
Contributions to pension fund	**(39)**	(38)	**(78)**	(76)
Expenditures on OPEB and supplementary pension	**(17)**	(16)	**(33)**	(30)
Expenditures on restructuring *(note 11)*	**(4)**	(1)	**(9)**	(43)
Net changes to other long-term assets and liabilities	**(20)**	(19)	**(29)**	(19)
Changes in non-cash working capital balances *(note 16)*	**(184)**	(209)	**(151)**	(132)
Cash flow provided by (used in) operating activities	**73**	(146)	**373**	77
Investing activities				
Investment in regulatory assets *(note 2)*	**(90)**	-	**(191)**	-
Investment in fixed assets	**(106)**	(127)	**(240)**	(223)
Cash flow (used in) investing activities	**(196)**	(127)	**(431)**	(223)
Financing activities				
Issuance of long-term debt *(note 6)*	**400**	5	**495**	13
Repayment of long-term debt *(note 6)*	**(1)**	(2)	**(2)**	(4)
Net decrease in short-term notes *(note 5)*	**-**	-	**(26)**	-
Cash flow provided by financing activities	**399**	3	**467**	9
Net increase (decrease) in cash and cash equivalents	**276**	(270)	**409**	(137)
Cash and cash equivalents, beginning of period	**135**	419	**2**	286
Cash and cash equivalents, end of period	**411**	149	**411**	149

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(millions of dollars)	**June 30 2005**	**December 31 2004**
Assets		
Current assets		
Cash and cash equivalents	**411**	2
Accounts receivable *(note 3)*	**397**	346
Future income taxes	**44**	44
Fuel inventory	**496**	569
Materials and supplies	**118**	92
	1,466	1,053
Fixed assets *(note 4)*		
Property, plant and equipment	**14,966**	15,114
Less: accumulated depreciation	**3,434**	3,174
	11,532	11,940
Other long-term assets		
Deferred pension asset	**546**	524
Nuclear fixed asset removal and nuclear waste management funds *(note 7)*	**6,376**	5,976
Long-term materials and supplies	**291**	281
Regulatory assets *(note 2)*	**191**	-
Long-term accounts receivable and other assets	**57**	56
	7,461	6,837
	20,459	19,830

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(millions of dollars)	**June 30 2005**	**December 31 2004**
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(notes 11 and 12)*	**834**	949
Market Power Mitigation Agreement rebate payable *(note 13)*	**245**	439
Revenue limit rebate payable *(note 14)*	**141**	-
Short-term notes payable *(note 5)*	**-**	26
Long-term debt due within one year *(note 6)*	**305**	5
Deferred revenue due within one year	**12**	12
Income and capital taxes payable	**23**	12
	1,560	1,443
Long-term debt *(note 6)*	**3,592**	3,399
Other long-term liabilities		
Fixed asset removal and nuclear waste management *(note 7)*	**8,555**	8,339
OPEB and supplementary pension	**1,163**	1,105
Long-term accounts payable and accrued charges	**186**	212
Deferred revenue	**150**	156
Future income taxes	**207**	155
	10,261	9,967
Shareholder's equity		
Common shares	**5,126**	5,126
Deficit	**(80)**	(105)
	5,046	5,021
	20,459	19,830

Commitments and Contingencies *(notes 1, 4, 5, 9, and 10)*

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2005 AND 2004 (UNAUDITED)

1. BASIS OF PRESENTATION

These interim consolidated financial statements were prepared following the same accounting policies and methods as in the most recent annual consolidated financial statements, except as discussed in Note 2 to the interim consolidated financial statements. However, these interim financial statements do not contain all the disclosures required by Canadian generally accepted accounting principles for annual financial statements. Accordingly, the interim consolidated financial statements should be read in conjunction with the most recently prepared annual consolidated financial statements for the year ended December 31, 2004.

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

Certain of the 2004 comparative amounts have been reclassified from financial statements previously presented to conform to the 2005 financial statement presentation.

The consolidated financial statements include the accounts of Ontario Power Generation Inc. and its subsidiaries. OPG accounts for its interests in jointly controlled entities using the proportionate consolidation method. All significant inter-company transactions have been eliminated on consolidation.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Changes in Accounting Policies

Rate Regulated Accounting

In December 2004, the *Electricity Restructuring Act, 2004* received Royal Assent. A regulation made pursuant to that statute prescribes that OPG's nuclear and baseload hydroelectric facilities will receive regulated prices for their output. Accounting standards recognize that rate regulation can create economic benefits and obligations, which are reported in the consolidated financial statements as regulatory assets and liabilities. If the regulation provides assurance that incurred costs will be recovered in the future, then a regulated entity may defer those costs and report them as a regulatory asset. If current recovery is provided for costs expected to be incurred in the future, then a regulated entity reports a regulatory liability.

Effective January 1, 2005, in accordance with regulations pursuant to the *Electricity Restructuring Act, 2004*, OPG is required to establish a deferral account in connection with non-capital costs that are associated with the return to service of units at the Pickering A nuclear generating station. Since this section of the regulation became effective January 1, 2005, the change in accounting was prospectively adopted on that date, with no retroactive adoption. As at June 30, 2005, the deferral account was $191 million, consisting of non-capital costs of $179 million relating to Unit 1 and $10 million relating to Units 2 and 3, and interest, accreted at the average cost of debt of 6.0 per cent, of $2 million. Upon OPG becoming regulated by the Ontario Energy Board ("OEB") in 2008, the OEB is directed by the regulation to ensure that OPG recovers any balance in the deferral account on a straight-line basis over a period not to exceed 15 years.

Effective April 1, 2005, in accordance with the regulations pursuant to the *Electricity Restructuring Act, 2004*, OPG was directed to establish a variance account for costs incurred on or after April 1, 2005 that are associated with differences in hydroelectric electricity production due to differences between forecast and actual water conditions, changes in nuclear electricity production due to unforeseen changes to the law or to unforeseen technological changes, changes to revenues assumed for ancillary revenues from the regulated facilities, acts of God (including severe weather events), and transmission outages and transmission restrictions. OPG recorded a liability as at June 30, 2005 of $4 million, reflecting water conditions that were favourable compared to those forecasted for the second quarter of 2005. Upon OPG becoming regulated by the Ontario Energy Board ("OEB") in 2008, the OEB is directed by the regulation to review the recovery and settlement of any balances established by OPG. Any balances approved by the OEB will be amortized on a straight-line basis over a period not to exceed three years.

Taxes

Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes related to the rate regulated segments of the business using the taxes payable method, as permitted for rate regulated operations. OPG continues to use the liability method of accounting for income taxes for its unregulated business only.

Under the taxes payable method, OPG will not be recognizing future income taxes related to the rate regulated segments of the business to the extent that these income taxes are expected to be recovered in the regulated rates charged to future customers. As a result, on April 1, 2005, OPG reversed the future income tax asset balance of $74 million relating to the rate regulated segments of the business, and recognized the amount as an extraordinary loss in determining net income. Had OPG continued to use the liability method for the regulated business, the future tax expense for the three months ended June 30, 2005 would have increased by $53 million, with a corresponding increase in the future income tax liability. As at June 30, 2005, the future income tax liability would have been $186 million.

Under the liability method, income taxes are recognized as a result of temporary differences arising from the difference between the tax basis of an asset or liability and its carrying value in the balance sheet, the carry-forward of unused tax losses and income tax reductions. Future income tax assets and liabilities are measured using income tax rates expected to apply in the years in which temporary differences are expected to reverse. The effect on future income tax assets and liabilities of a change in tax rates is included in income in the period the change is substantively enacted. Future income tax assets are evaluated and if realization is not considered more likely than not, a valuation allowance is established.

The extraordinary item reduced basic and diluted earnings per share for the three and six month periods ended June 30, 2005 by $0.28.

New Accounting Recommendations

Consolidation of Variable Interest Entities

In September 2004, the CICA amended Accounting Guideline 15, *Consolidation of Variable Interest Entities*, originally issued in June 2003, to harmonize with the revised Financial Accounting Standards Board ("FASB") Interpretation No. 46, *Consolidation of Variable Interest Entities* ("FIN 46R"). The new guideline requires the consolidation of variable interest entities ("VIEs") by the primary beneficiary. A VIE is an entity where (a) its equity investment at risk is insufficient to permit the entity to finance its activities without additional subordinated support from others and/or where certain essential characteristics of a controlling financial interest are not met, and (b) it does not meet specified exemption criteria. The primary beneficiary is the enterprise that will absorb or receive the majority of the VIEs' expected losses, expected residual returns, or both.

OPG is involved with various joint venture and other arrangements and has sold trade receivables under an asset securitization arrangement. The Company assessed these arrangements in advance of the guideline becoming effective January 1, 2005. OPG concluded that the joint venture arrangements with which it is involved are not VIEs, and that it is not the primary beneficiary of, nor does it have a significant variable interest in, the trust to which it sold trade receivables. OPG has completed the review of its other arrangements and determined that there is no impact on OPG's existing accounting for these arrangements.

3. Sale of Accounts Receivable

On October 1, 2003, the Company signed an agreement to sell an undivided co-ownership interest in its current and future accounts receivable (the "receivables") to an independent trust. The Company also retains an undivided co-ownership interest in the receivables sold to the trust. Under the agreement, OPG continues to service the receivables. The transfer provides the trust with ownership of a share of the payments generated by the receivables, computed on a monthly basis. The trust's recourse to the Company is generally limited to its income earned on the receivables.

OPG reflected the initial transfer to the trust of the co-ownership interest, and subsequent transfers required by the revolving nature of the securitization, as sales in accordance with CICA Accounting Guideline 12, *Transfer of Receivables*. In accordance with this Guideline, the proceeds of each sale to the trust were deemed to be the cash received from the trust net of the undivided co-ownership interest retained by the Company. For the three months ended June 30, 2005, the Company has recognized pre-tax charges of $2 million (three months ended June 30, 2004 – $2 million) on such sales at an average cost of funds of 2.9 per cent (three months ended June 30, 2004 – 2.3 per cent). For the six months ended June 30, 2005, the Company has recognized pre-tax charges of $4 million (six months ended June 30, 2004 – $4 million) on such sales at an average cost of funds of 2.9 per cent (six months ended June 30, 2004 – 2.5 per cent). As at June 30, 2005, OPG had sold receivables of $300 million from its total portfolio of $567 million.

4. Fixed Assets

Depreciation and amortization expense for the three and six months ended June 30, 2005 and 2004 consists of the following:

	Three Months Ended June 30		**Six Months Ended June 30**	
(millions of dollars)	**2005**	**2004**	**2005**	**2004**
Depreciation and amortization	**190**	193	**382**	383
Nuclear waste management costs	**2**	1	**3**	3
	192	194	**385**	386

Interest capitalized to construction in progress at 6.0 per cent during the three and six months ended June 30, 2005 (three and six months ended June 30, 2004 – 6.0 per cent) was $9 million and $17 million respectively (three and six months ended June 30, 2004 – $9 million and $17 million).

Impairment of Long-Lived Assets

The accounting estimates related to asset impairment require significant management judgment to identify factors such as short and long-term forecasts for future sales prices, the supply of electricity in Ontario, the return to service dates of laid-up generating stations, inflation, fuel prices and station lives. The amount of the future cash flow that OPG will ultimately realize with respect to these assets could differ materially from the carrying values recorded in the consolidated financial statements.

Pickering A Nuclear Generating Station Units 2 and 3

OPG recently completed an assessment of the cost, schedule and risks related to the return to service of Units 2 and 3 at the Pickering A nuclear generating station. This included an assessment of the ability of these units to perform at an acceptable capability factor over the remaining 12 to 20 years of operations. This assessment incorporated recent findings from inspection programs with respect to feeder pipe and steam generator degradation mechanisms, and potential degradation of the calandria vault components, all of which could impact the future capability factor, operating costs and the life of the units. Upon consideration of the scope of the refurbishment work, the costs and the risks related to the return to service of these two units, and the Company's focus on improving the performance of its other nuclear units, OPG's Board of Directors decided that while technically feasible, the return to service of these units was not justified on a commercial basis. Accordingly, OPG recorded an impairment loss in the second quarter of 2005 related to the carrying amount of these two units including construction in progress, which was $63 million at June 30, 2005.

OPG expects to recover the amounts recorded in the deferral account relating to non-capital costs incurred after January 1, 2005 associated with the return to service of Units 2 and 3. As at June 30, 2005, the deferral account relating to Units 2 and 3 was $10 million.

As a result of the decision not to proceed with the return to service of these two units, OPG will have to assess the need to provide for any additional costs, including the cost associated with preparing the units for safe storage, any impacts on cost estimates for asset retirement obligation, any excess inventory, and any other additional exit costs. These potential additional charges are not specifically determinable at this time, however a detailed assessment of these associated costs will be completed during the remainder of 2005. Such charges may have a significant impact on operating results in future periods.

Lennox Generating Station

As a result of the Government's "Request for Information/Request for Proposal for 2,500 MW of New Clean Generation and Demand Side Management Projects" released in September 2004 and the related contractual arrangements, future wholesale electricity market revenue is expected to be lower than previously anticipated. As a relatively high variable cost plant, the Lennox generating station will not be able to recover its fixed operating costs and its carrying value from the wholesale electricity market in the future. Given these factors, OPG had initiated discussions with the Province, with the expectation of entering into a contractual arrangement for the recovery of the annual fixed operating costs and the carrying value of the Lennox generating station. In March 2005, OPG was advised by the Province that it would continue to support OPG in negotiating an arrangement that would allow for the recovery of fixed operating costs, but that the Province would not support an arrangement that would allow for the recovery of the carrying value of the Lennox generating station. As a result of this change in circumstance, OPG recorded the impairment loss of $202 million in the first quarter of 2005. OPG has since negotiated an arrangement with the Independent Electricity System Operator ("IESO") to recover its fixed operating costs for a one-year period ending July 31, 2006. The arrangement with the IESO is subject to approval by the OEB.

5. SHORT-TERM CREDIT FACILITIES

OPG's current 364-day term $1,000 million revolving committed bank credit facility was renewed on May 24, 2005. The new facility is divided into two tranches – a $500 million 364-day term tranche maturing May 23, 2006, and a $500 million three-year term tranche maturing May 23, 2008. The total credit facility will continue to be used primarily as support for notes issued under OPG's commercial paper program. As at June 30, 2005, OPG had no borrowings outstanding under this commercial paper program (December 31, 2004 – $26 million). As at June 30, 2005 and December 31, 2004, OPG had no other outstanding borrowing under this facility.

OPG also maintains $26 million (December 31, 2004 – $26 million) in short-term uncommitted overdraft facilities as well as $213 million (December 31, 2004 – $200 million) of short-term uncommitted credit facilities, which support the issuance of Letters of Credit. OPG uses Letters of Credit to support the supplementary pension plan, and is required to post the Letters of Credit as collateral with Local Distribution Companies ("LDCs") as prescribed by the Ontario Energy Board's ("OEB") Retail Settlement Code. At June 30, 2005, there were approximately $158 million (December 31, 2004 – $155 million) of Letters of Credit issued for the supplementary pension plan and collateral requirements to the LDCs.

6. Long-Term Debt

Long-term debt consists of the following:

(millions of dollars)	June 30 2005	December 31 2004
Notes payable to the OEFC	**3,695**	3,200
Capital lease obligations	**1**	3
Share of non-recourse limited partnership debt	**201**	201
	3,897	3,404
Less: due within one year		
Notes payable to the OEFC	**300**	-
Capital lease obligations	**1**	3
Share of limited partnership debt	**4**	2
	305	5
Long-term debt	**3,592**	3,399

Holders of the senior debt are entitled to receive, in full, amounts owing in respect of the senior debt before holders of the subordinated debt are entitled to receive any payments. The Ontario Electricity Financial Corporation ("OEFC") currently holds all of OPG's outstanding senior and subordinated notes.

In December 2004, OPG reached an agreement with the OEFC to defer payment on $500 million principal amount of senior notes maturing in March and September 2005 by extending the maturity dates by five years. The interest rates remain unchanged. In March 2005, the Company reached an agreement with the OEFC to obtain additional financing up to $600 million, which can be drawn until March 31, 2006. In April 2005, $400 million was drawn under this facility, with a seven year term.

The Company also reached an agreement with the OEFC to satisfy, through the issue of additional senior notes of $95 million and $98 million respectively, to mature in 2010, its $95 million interest obligation due in March 2005 and the $98 million interest obligation due in September 2005 related to the debt owing to the OEFC of $3.2 billion.

Interest paid during the three months ended June 30, 2005 was $16 million (three months ended June 30, 2004 – $7 million), of which $10 million relates to interest paid on long-term debt (three months ended June 30, 2004 – $4 million). Interest paid during the six months ended June 30, 2005 was $119 million (six months ended June 30, 2004 – $111 million), of which $110 million relates to interest paid on long-term debt (six months ended June 30, 2004 – $105 million). Interest on the notes payable to the OEFC is paid in the first and third quarters of the year.

7. Fixed Asset Removal and Nuclear Waste Management

The liability for fixed asset removal and nuclear waste management on a present value basis consists of the following:

(millions of dollars)	June 30 2005	December 31 2004
Liability for nuclear used fuel management	**4,821**	4,693
Liability for nuclear decommissioning and low and intermediate level waste management	**3,544**	3,457
Liability for non-nuclear fixed asset removal	**190**	189
Fixed asset removal and nuclear waste management liability	**8,555**	8,339

The change in the fixed asset removal and nuclear waste management liability for the six months ended June 30, 2005 and year ended December 31, 2004, is as follows:

(millions of dollars)	**June 30 2005**	**December 31 2004**
Liability, beginning of period	**8,339**	7,921
Increase in liability due to accretion	**239**	453
Increase in liability due to nuclear used fuel and nuclear waste management variable expenses	**16**	35
Fixed asset removal of partnership interests	**-**	1
Liabilities settled by expenditures on waste management	**(39)**	(71)
Liability, end of period	**8,555**	8,339

Ontario Nuclear Funds Agreement

OPG sets aside funds to be used specifically for discharging its nuclear fixed asset removal and nuclear waste management liabilities. The nuclear fixed asset removal and nuclear waste management funds as at June 30, 2005 and December 31, 2004, consist of the following:

	Amortized Cost Basis		**Fair Value**	
(millions of dollars)	**June 30 2005**	**December 31 2004**	**June 30 2005**	**December 31 2004**
Decommissioning Fund	**3,973**	3,858	**4,313**	4,131
Used Fuel Fund[1]	**2,403**	2,118	**2,403**	2,118
	6,376	5,976	**6,716**	6,249

[1] The Ontario NFWA Trust represents $924 million as at June 30, 2005 (December 31, 2004 – $794 million) of the Used Fuel Fund on an amortized cost basis.

8. BENEFIT PLANS

The post employment benefit programs include pension, group life insurance, health care and long-term disability benefits. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, changes in assumptions and experience gains or losses. The 2005 costs are based on a measurement of the pension and OPEB obligations and the pension fund assets, at December 31, 2004.

Total benefit costs for the three and six months ended June 30, 2005 and 2004, are as follows:

	Three Months Ended June 30		**Six Months Ended June 30**	
(millions of dollars)	**2005**	**2004**	**2005**	**2004**
Registered pension plan	**28**	23	**56**	46
Supplementary pension plan	**5**	4	**9**	8
OPEB	**41**	37	**82**	73

9. FINANCIAL INSTRUMENTS

Fair values of derivative instruments have been estimated by reference to quoted market prices for actual or similar instruments where available. Where quoted market prices are not available, OPG considers various factors to estimate forward prices, including market prices and price volatility in neighbouring electricity markets, market prices for fuel, and other factors.

Trading activities and liquidity in the Ontario electricity market have been limited as companies are generally entering only into short-term contracts. As a result, forward pricing information for contracts may not accurately represent the cost to enter into these contracts. For Ontario-based contracts that are not entered into for hedging purposes, OPG established liquidity reserves against the fair market value of the assets and liabilities equal to the gain or loss on these contracts. These reserves increased trading revenue by $7 million during the six months ended June 30, 2005 (six months ended June 30, 2004 – $2 million). Contracts for transactions outside of Ontario continue to be carried on the consolidated balance sheets as assets or liabilities at fair value, with changes in fair value recorded in trading revenue as gains or losses.

Derivative Instruments Used for Hedging Purposes

The following table provides the estimated fair value of derivative instruments designated as hedges. The majority of OPG's derivative instruments are treated as hedges, with gains or losses recognized upon settlement when the underlying transactions occur. OPG holds financial commodity derivatives primarily to hedge the commodity price exposure associated with changes in the price of electricity.

(millions of dollars except where noted)	**Notional Quantity**	**Terms**	**Fair Value**	**Notional Quantity**	**Terms**	**Fair Value**
		June 30, 2005			**December 31, 2004**	
(Loss)/gain						
Electricity derivative instruments	**6.0 TWh**	**1-3 yrs**	**(101)**	10.4 TWh	1-3 yrs	(71)
Foreign exchange derivative instruments	**US $8**	**July/05**	**-**	US $10	Jan/05	-

Foreign exchange derivative instruments are used to hedge the exposure to anticipated U.S. dollar denominated purchases. The weighted average fixed exchange rate for contracts outstanding at June 30, 2005 was US $0.82 (December 31, 2004 – US $0.81) for every Canadian dollar.

Derivative Instruments Not Used for Hedging Purposes

The carrying amount (fair value) of derivative instruments not designated for hedging purposes is as follows:

(millions of dollars except where noted)	**Notional Quantity**	**Fair Value**	**Notional Quantity**	**Fair Value**
	June 30, 2005		**December 31, 2004**	
Commodity derivative instruments				
Assets	**5.9 TWh**	**6**	7.9 TWh	12
Liabilities	**1.7 TWh**	**(19)**	1.3 TWh	(12)
		(13)		-
Ontario market liquidity reserve		**-**		(7)
Total		**(13)**		(7)

10. Commitments and Contingencies

Litigation and Claims

Various lawsuits are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of its business activities. In July 2004, OPG was charged with criminal negligence causing death and criminal negligence causing bodily harm in relation to a 2002 accident at Barrett Chute. Also, certain First Nations have commenced actions for interference with reserve and traditional land rights. The claims by some of these First Nations total approximately $50 million and claims by others are for unspecified amounts. Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably with respect to OPG. These contingencies are provided for when they are likely to occur and are reasonably estimable. Management believes that the ultimate resolution of these matters will not have a material effect on OPG's financial position.

OPG has become aware, very recently, of a class action suit that has been issued against it and 20 U.S.-based electricity generators relating to the use of coal as fuel at some of its facilities. The merits, if any, will be determined in a timely and appropriate manner.

Guarantees

As part of normal business, OPG and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees, standby Letters of Credit and surety bonds.

OPG has provided limited guarantees in connection with its share of the Brighton Beach financing, whereby it is responsible for contributing its share of equity related to cost overruns associated with the construction of the generating station. As at June 30, 2005, OPG met its obligations for contributing its share of equity related to cost overruns. As Brighton Beach commenced commercial operation in July 2004, any cost overruns are now primarily limited to settlement of construction liens registered by some contractors associated with the construction project. Brighton Beach arranged an independent third party review of the claims and is now actively negotiating final settlement of these liens.

11. Restructuring

The change in the restructuring liability for termination benefits for the six months ended June 30, 2005 and year ended December 31, 2004 is as follows:

(millions of dollars)	**June 30 2005**	**December 31 2004**
Liability, beginning of period	**20**	52
Restructuring charges	**-**	19
Payments	**(9)**	(51)
Liability, end of period	**11**	20

During 2004, OPG recorded restructuring charges of $16 million, which consisted of $15 million for termination benefits and $1 million in related pension and OPEB expenses associated with its Lakeview generating station. OPG also recorded restructuring charges of $4 million related to its Energy Marketing segment during 2004.

12. TRANSITION RATE OPTION CONTRACTS

Under regulation known as Transition – Generation Corporation Designated Rate Options ("TRO"), OPG has been required to provide transitional price relief since market opening to certain power customers for up to four years based on the consumption and average price paid by each customer during a reference period of July 1, 1999 to June 30, 2000. The TRO is treated as a hedge of generation revenue. The maximum anticipated volume subject to the transitional price relief was approximately 5.4 TWh in the first year after market opening and 3.6 TWh in the second year. The maximum anticipated volume in each of the third and fourth years is 1.8 TWh. The maximum length of the program is four years, which expires April 30, 2006.

A provision of $210 million on the TRO contracts was recorded in the first quarter of 2002 based on the estimated future loss on these contracts. The provision was determined at that time using management's best estimates of the forward price curve for electricity, wholesale electricity market fees, impact of decontrol on these contracts, interruptions of volume, and the recovery of Market Power Mitigation Agreement rebates. The provision for the TRO contracts was established based on meeting decontrol targets within three years of market opening. An additional charge of $30 million related to the fourth year of the TRO contracts was recorded in 2003, based on OPG's expectation that the Company would not meet the decontrol targets necessary for TRO contracts to expire after three years.

The change in the TRO contracts provision for the six months ended June 30, 2005 and year ended December 31, 2004 is as follows:

(millions of dollars)	**June 30 2005**	**December 31 2004**
Provision, beginning of period	**48**	100
Decrease of provision during the period	**(18)**	(52)
Provision, end of period	**30**	48

13. MARKET POWER MITIGATION AGREEMENT REBATE

Until April 1, 2005, OPG was required under its generating licence to comply with prescribed market power mitigation measures to address the potential for OPG to exercise market power in Ontario. The market power mitigation measures included both a rebate mechanism and the requirement to decontrol generating capacity. Under the rebate mechanism, a majority of OPG's expected energy sales in Ontario were subject to an average annual revenue cap of 3.8¢/kWh. During the term of the Market Power Mitigation Agreement, OPG was required to pay a rebate to the Independent Electricity System Operator equal to the excess, if any, of the average hourly spot energy price over 3.8¢/kWh for a 12-month settlement period, multiplied by the amount of energy subject to the rebate mechanism. The Market Power Mitigation Agreement was replaced effective April 1, 2005 by a regulated price for baseload hydroelectric and nuclear generation and a revenue limit that applies to OPG's unregulated generation assets.

In accordance with the Market Power Mitigation Agreement, the rebate is calculated after taking into account the amount of energy sales subject to the rebate mechanism for only those generating stations that OPG continues to control. Since the average hourly spot price during the three months ended March 31, 2005, when the rebate mechanism ended, exceeded the 3.8¢/kWh revenue cap, OPG provided $412 million (three months ended March 31, 2004 – $441 million) as a Market Power Mitigation Agreement rebate. During the six months ended June 30, 2004, OPG provided $649 million as a Market Power Mitigation Agreement rebate.

The change in the Market Power Mitigation Agreement rebate liability for the six months ended June 30, 2005 and year ended December 31, 2004 is as follows:

(millions of dollars)	**June 30 2005**	**December 31 2004**
Liability, beginning of period	**439**	409
Increase to provision during the period	**412**	1,154
Payments	**(606)**	(1,124)
Liability, end of period	**245**	439

14. REVENUE LIMIT REBATE

A regulation made pursuant to the *Electricity Restructuring Act, 2004* requires that 85 per cent of the generation output from OPG's unregulated generation assets, excluding the Lennox generating station, TRO volumes and forward sales as of January 1, 2005, are subject to a revenue limit based on an average price of $47.00/MWh (4.7¢/kWh). This revenue limit is in place for a period of 13 months ending April 30, 2006. Revenues above this limit will be rebated at the end of the period.

The change in the revenue limit rebate liability for the six months ended June 30, 2005 is as follows:

(millions of dollars)	**June 30 2005**
Liability, beginning of period	-
Increase to provision during the year	141
Payments	-
Liability, end of period	141

15. BUSINESS SEGMENTS

A regulation made pursuant to the *Electricity Restructuring Act, 2004* provided that OPG would receive regulated prices for its baseload hydroelectric and nuclear facilities. These initial prices took effect April 1, 2005, and are expected to remain in effect until at least March 31, 2008, at which time it is anticipated that the Ontario Energy Board ("OEB") will have established new regulated prices. Given the effective date of these prices, and the OPG's management approach, OPG changed its definition of business segments on April 1, 2005 from Generation and Energy Marketing to Regulated – Nuclear, Regulated – Hydroelectric and Unregulated Generation. OPG will continue to report other activities, including the previously separately presented trading activities in the Other category. As a result of this change in definition, OPG has reclassified the comparative periods to be consistent with the current presentation of business segments.

Segment Income for three months ended June 30, 2005	**Regulated – Nuclear**	**Regulated – Hydroelectric**	**Unregulated Generation**	**Other**	**Total**
(millions of dollars)					
Revenues					
Revenue	**540**	**202**	**744**	**28**	**1,514**
Market Power Mitigation Agreement rebate	**-**	**-**	**-**	**-**	**-**
Revenue limit rebate	**-**	**-**	**(141)**	**-**	**(141)**
	540	**202**	**603**	**28**	**1,373**
Fuel expense	**25**	**69**	**195**	**-**	**289**
Gross margin	**515**	**133**	**408**	**28**	**1,084**
Operations, maintenance and administration	**441**	**18**	**142**	**15**	**616**
Depreciation and amortization	**94**	**16**	**74**	**8**	**192**
Accretion on fixed asset removal and nuclear waste management liabilities	**117**	**-**	**3**	**-**	**120**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(112)**	**-**	**-**	**-**	**(112)**
Property and capital taxes	**11**	**5**	**8**	**(7)**	**17**
Operating (loss) income	**(36)**	**94**	**181**	**12**	**251**
Impairment of long-lived assets	**63**	**-**	**-**	**-**	**63**
(Loss) income before interest, income taxes and extraordinary item	**(99)**	**94**	**181**	**12**	**188**

Segment Income for three months ended June 30, 2004	**Regulated – Nuclear**	**Regulated – Hydroelectric**	**Unregulated Generation**	**Other**	**Total**
(millions of dollars)					
Revenues					
Revenue	545	244	544	16	1,349
Market Power Mitigation Agreement rebate	(64)	(37)	(107)	-	(208)
	481	207	437	16	1,141
Fuel expense	24	64	154	-	242
Gross margin	457	143	283	16	899
Operations, maintenance and administration excluding Pickering A return to service	397	18	140	13	568
Pickering A return to service	65	-	-	-	65
Depreciation and amortization	93	18	76	7	194
Accretion on fixed asset removal and nuclear waste management liabilities	112	-	2	-	114
Earnings on nuclear fixed asset removal and nuclear waste management funds	(80)	-	-	-	(80)
Property and capital taxes	4	6	13	7	30
Restructuring	-	-	16	-	16
(Loss) income before interest, income taxes and extraordinary item	(134)	101	36	(11)	(8)

Segment Income for six months ended June 30, 2005	Regulated – Nuclear	Regulated – Hydroelectric	Unregulated Generation	Other	Total
(millions of dollars)					
Revenues					
Revenue	**1,280**	**472**	**1,485**	**47**	**3,284**
Market Power Mitigation Agreement rebate	**(160)**	**(65)**	**(187)**	**-**	**(412)**
Revenue limit rebate	**-**	**-**	**(141)**	**-**	**(141)**
	1,120	**407**	**1,157**	**47**	**2,731**
Fuel expense	**54**	**122**	**423**	**-**	**599**
Gross margin	**1,066**	**285**	**734**	**47**	**2,132**
Operations, maintenance and administration	**859**	**36**	**279**	**29**	**1,203**
Depreciation and amortization	**186**	**34**	**148**	**17**	**385**
Accretion on fixed asset removal and nuclear waste management liabilities	**234**	**-**	**5**	**-**	**239**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(183)**	**-**	**-**	**-**	**(183)**
Property and capital taxes	**22**	**9**	**16**	**(9)**	**38**
Operating (loss) income	**(52)**	**206**	**286**	**10**	**450**
Impairment of long-lived assets	**63**	**-**	**202**	**-**	**265**
(Loss) income before interest, income taxes and extraordinary item	**(115)**	**206**	**84**	**10**	**185**

Segment Income for six months ended June 30, 2004	Regulated – Nuclear	Regulated – Hydroelectric	Unregulated Generation	Other	Total
(millions of dollars)					
Revenues					
Revenue	1,197	527	1,377	39	3,140
Market Power Mitigation Agreement rebate	(206)	(106)	(337)	-	(649)
Revenue limit rebate	-	-	-	-	-
	991	421	1,040	39	2,491
Fuel expense	54	115	411	-	580
Gross margin	937	306	629	39	1,911
Operations, maintenance and administration excluding Pickering A return to service	796	35	277	25	1,133
Pickering A return to service	124	-	-	-	124
Depreciation and amortization	186	33	154	13	386
Accretion on fixed asset removal and nuclear waste management liabilities	223	-	4	-	227
Earnings on nuclear fixed asset removal and nuclear waste management funds	(178)	-	-	-	(178)
Property and capital taxes	12	11	23	12	58
Restructuring	-	-	16	-	16
(Loss) income before interest, income taxes and extraordinary item	(226)	227	155	(11)	145

Selected Balance Sheet Information	Regulated – Nuclear	Regulated – Hydroelectric	Unregulated Generation	Other	Total
(millions of dollars)					
June 30, 2005					
Segment property, plant and equipment, net	3,228	4,018	3,675	611	11,532
December 31, 2004					
Segment property, plant and equipment, net	3,305	4,016	3,985	634	11,940
Selected Cash Flow Information					
(millions of dollars)					
Three months ended June 30, 2005					
Capital expenditures	66	21	19	-	106
Three months ended June 30, 2004					
Capital expenditures	76	6	16	29	127
Six months ended June 30, 2005					
Capital expenditures	160	37	36	7	240
Six months ended June 30, 2004					
Capital expenditures	132	12	29	50	223

16. CHANGES IN NON-CASH WORKING CAPITAL BALANCES

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2005**	**2004**	**2005**	**2004**
Accounts receivable	**38**	16	**(51)**	36
Income taxes recoverable	**-**	4	**-**	16
Fuel inventory	**(26)**	(127)	**73**	(11)
Materials and supplies	**(12)**	(1)	**(26)**	(17)
Market Power Mitigation Agreement rebate payable	**(386)**	(130)	**(194)**	(3)
Revenue limit rebate payable	**141**	-	**141**	-
Accounts payable and accrued charges	**58**	22	**(105)**	(160)
Income and capital taxes payable	**3**	7	**11**	7
	(184)	(209)	**(151)**	(132)

The amount of cash income taxes paid in the three and six months ended June 30, 2005 was $5 million and $9 million (three and six months ended June 30, 2004 – $2 million and $5 million).

17. SEASONAL OPERATIONS

OPG's quarterly results are impacted by changes in demand resulting from variations in seasonal weather conditions. Historically, OPG's revenues are higher in the first and third quarters of a fiscal year as a result of winter heating demands in the first quarter and air conditioning/cooling demands in the third quarter. The Market Power Mitigation Agreement rebate and OPG's hedging strategies significantly reduced the impact of seasonal price fluctuations on the results of operations. Commencing April 1, 2005, regulated prices for the baseload hydroelectric and nuclear facilities and the revenue limit related to the generation from OPG's other generating assets will further reduce the impact of seasonal price fluctuations on operating results.