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News
from Ontario Power Generation

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August 17, 2006

ONTARIO POWER GENERATION REPORTS 2006 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, 2006. Net income for the three months ended June 30, 2006 was $143 million compared to net income of $63 million for the same period in 2005. For the six months ended June 30, 2006, net income was $342 million compared to $25 million for the same period last year.

"Our second quarter results reflect the continuing performance improvements of our generating stations. Our electricity production equalled that of the second quarter of 2005 due to an increase in low marginal cost nuclear production, largely offset by a decline in fossil generation. In addition, we are successfully pursuing a number of projects aimed at increasing Ontario's electricity supply," said President and CEO Jim Hankinson.

Net income for the three months ended June 30, 2006 of $143 million was favourably impacted by an increase in gross margin from electricity sales primarily due to higher nuclear generation compared to the same period in 2005, partially offset by lower Ontario spot market prices. The improved gross margin was offset by an increase in pension and other post employment benefits costs, compared to the same period in 2005, due to changes in economic assumptions used to measure the costs. During the second quarter of 2005, OPG recorded an impairment charge of $63 million related to Units 2 and 3 of the Pickering A nuclear generating station, as a result of a decision not to proceed with the return to service of these units. In addition, during the second quarter of 2005, as part of the transition to a rate regulated environment, OPG adopted regulatory accounting for the rate regulated segments of its business. As a result, OPG eliminated a net future income tax asset of $74 million and recorded a corresponding one-time extraordinary loss.

Net income for the six months ended June 30, 2006 of $342 million was favourably impacted by an increase in gross margin from electricity sales due primarily to higher nuclear production compared to the same period in 2005, together with the introduction of regulated prices and other related regulatory changes effective April 1, 2005. Higher pension and other post employment benefit costs unfavourably affected earnings for the six months ended June 30, 2006. Net income during the six months ended June 30, 2005 was unfavourably affected by an impairment charge of $202 million related to OPG's Lennox generating station reflecting a determination that the station would not be able to recover its carrying value from the wholesale electricity market in the future, in addition to the impairment charge related to Units 2 and 3 of the Pickering A nuclear generating station, and the elimination of the net future income tax asset referred to above.

Electricity generated in the second quarter of 2006 of 25.5 terawatt hours (TWh) equalled that of the second quarter of 2005. Nuclear production increased by 19 per cent primarily as a result of the return to service of Unit 1 at the Pickering A nuclear generating station, and the impact of a shutdown of Unit 4 at the same station in the second quarter of 2005 for inspection and replacement of feeder pipes. Regulated - Hydroelectric generation decreased due to lower water levels in the Niagara and St. Lawrence watersheds and Unregulated – Hydroelectric generation increased due to higher water levels in the northwestern and eastern watersheds. Fossil generation declined primarily as a result of lower Ontario electricity demand and higher nuclear generation.

For the six months ended June 30, 2006, total production from OPG's generating stations was 53.9 TWh compared to 54.3 TWh for the same period in 2005. This marginal decrease was primarily due to lower fossil-fuelled generation due to lower electricity demand, partially offset by higher nuclear generation.

OPG is continuing to pursue a number of electricity generation projects aimed at increasing Ontario's electricity supply, including the following:

- 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;
- Construction of a new 12.5 MW Lac Seul hydroelectric generating station on the English River that started during the first quarter of 2006 and is expected to be completed in the fourth quarter of 2007;
- Development of the Portlands Energy Centre ("PEC"), a 550 MW gas-fired, combined cycle station near downtown Toronto is proceeding. The Ontario Power Authority ("OPA") has provided interim financial guarantees for certain project costs. PEC has entered into an agreement for preliminary engineering, procurement, and early site work and is negotiating a design-build contract; and
- OPG has been directed to proceed with the definition phase for a 450 MW hydroelectric development, which includes the replacement and expansion of certain hydroelectric generating stations located on the Lower Mattagami River.

In June 2006, the Minister of Energy directed OPG to undertake feasibility studies to refurbish units at the Pickering and Darlington nuclear generating stations and to begin an environmental assessment on the refurbishment of the four existing units at the Pickering B generating station. OPG was also directed to begin a federal approval process, including an environmental assessment, for new nuclear units at an existing site.

The government has accepted the advice of the Independent Electricity System Operator that indicated a need for 2,500 to 3,000 megawatts of additional capacity to maintain system reliability. As a result, the Ministry of Energy has since directed the OPA to determine how best to replace coal-fired generation and the earliest time frame in which it can be achieved. The OPA has also been asked to recommend options for cost-effective measures to reduce air emissions from coal-fired generation.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars – except where noted)	**2006**	**2005**	**2006**	**2005**
Earnings				
Revenue after revenue limit and Market Power Mitigation Agreement rebates	**1,345**	1,373	**2,853**	2,731
Fuel expense	**243**	289	**521**	599
Gross margin	**1,102**	1,084	**2,332**	2,132
Operations, maintenance and administration	**683**	616	**1,333**	1,203
Other expenses	**273**	264	**559**	573
Impairment of long-lived assets	**-**	63	**-**	265
Income tax expenses (recoveries)	**3**	4	**98**	(8)
Extraordinary item	**-**	74	**-**	74
Net income	**143**	63	**342**	25
Cash flow				
Cash flow (used in) provided by operating activities	**(435)**	73	**(1)**	373
Electricity Generation (TWh)				
Regulated – Nuclear	**11.2**	9.4	**23.9**	21.4
Regulated – Hydroelectric	**4.4**	5.0	**8.9**	9.6
Unregulated – Hydroelectric	**4.6**	4.4	**8.8**	8.2
Unregulated – Fossil-Fuelled	**5.3**	6.7	**12.3**	15.1
Total electricity generation	**25.5**	25.5	**53.9**	54.3
Average electricity sales price [1] (¢/kWh)				
Regulated – Nuclear [2]	**4.9**	4.9	**4.9**	4.6
Regulated – Hydroelectric [2]	**3.4**	3.9	**3.5**	4.1
Unregulated – Hydroelectric [3]	**4.6**	5.1	**4.7**	4.8
Unregulated – Fossil-Fuelled [3]	**4.7**	5.5	**4.8**	4.9
OPG average sales price	**4.6**	4.9	**4.6**	4.6
Nuclear unit capability factor (per cent)				
Darlington	**80.2**	80.4	**87.4**	87.1
Pickering A	**84.3**	1.9	**87.8**	50.6
Pickering B	**71.6**	72.9	**75.1**	78.6
Equivalent forced outage rate (per cent)				
Unregulated– Fossil-Fuelled	**15.7**	16.8	**12.9**	16.1
Availability (per cent)				
Regulated – Hydroelectric	**90.5**	92.3	**91.6**	92.1
Unregulated– Hydroelectric	**95.4**	96.3	**94.8**	95.7

1 Prior to the inception of rate regulation on April 1, 2005, OPG's electricity generation received the Ontario spot electricity market price net of the Market Power Mitigation Agreement rebate.

2 After April 1, 2005, electricity generation from stations in the Regulated – Nuclear segment received a fixed price of 4.95¢/kWh. During the same period, electricity generation from stations in the Regulated – Hydroelectric segment received a fixed price of 3.3¢/kWh for the first 1,900 MWh of generation in any hour, and the Ontario spot electricity market price for generation above this level.

3 During the period from April 1, 2005 to April 30, 2006, 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. Starting May 1, 2006 the revenue limit decreased to 4.6¢/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 as at and for the three and six months ended June 30, 2006 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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2006 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, 2006. For a complete description of OPG's corporate strategies, risk management, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A 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, 2005. 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 16, 2006.

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 does not indicate that a statement is not forward-looking.

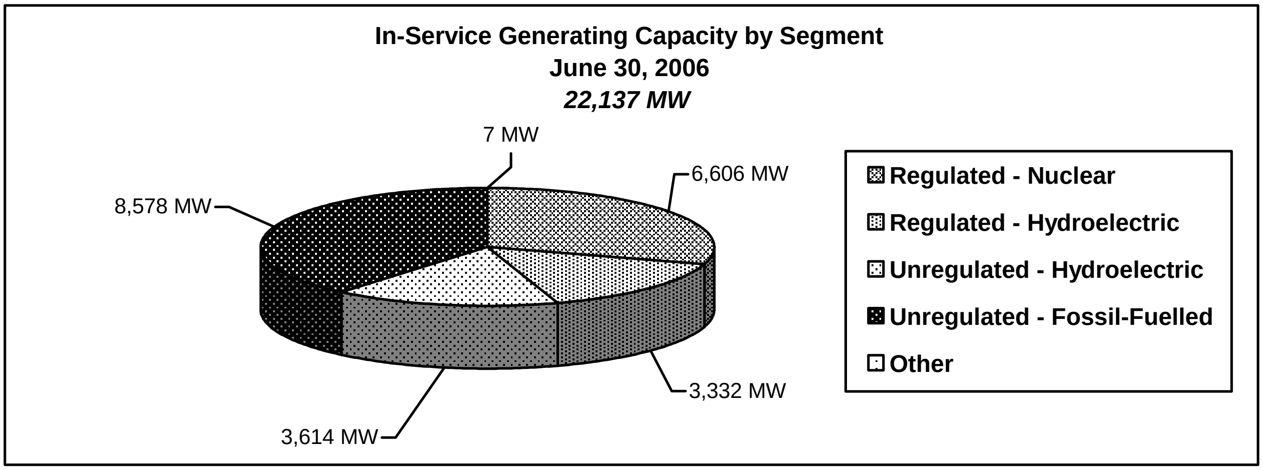
All forward-looking statements involve inherent assumptions, risks and uncertainties and, therefore, could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's fuel costs and availability, nuclear decommissioning and waste management, closure of coal-fired generating stations, refurbishment of existing facilities, development and construction of new facilities, pension and other post employment benefit ("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 forward-looking statements included in this MD&A are made only as of the date of this MD&A. OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise.

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, 2006, OPG's electricity generating portfolio had an in-service capacity of 22,137 megawatts ("MW"). OPG's electricity generating portfolio consists 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). 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 operated by OPG 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 on the majority of this output. With the introduction of rate regulation, OPG revised its reportable business segments to separately reflect the regulated and unregulated aspects of its business. Since the second quarter of 2005, OPG reported its business segments as Regulated – Nuclear, Regulated – Hydroelectric, and Unregulated Generation. Beginning in the first quarter of 2006, OPG separated the Unregulated Generation business segment into two reportable segments, identified as Unregulated – Fossil-Fuelled and Unregulated – Hydroelectric, as a result of changes in the management structure of these segments. Results for the comparative periods have been reclassified accordingly.



RATE REGULATION

A regulation was introduced pursuant to the *Electricity Restructuring Act, 2004*, (Ontario),which provides that, effective April 1, 2005, OPG receives regulated prices for electricity generated from most of its baseload hydroelectric and all of its nuclear facilities. This comprises electricity generated from the 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 electricity production during peak demand periods, any production from these regulated hydroelectric facilities above 1,900 MWh in any hour receives the Ontario electricity 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 variance accounts 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 and forward sales as of January 1, 2005, is subject to a revenue limit. The output from a generating unit where there has been a fuel conversion and the incremental output from a generating station where there has been a refurbishment or expansion of these assets is also excluded from the output covered by the revenue limit. In addition, until the Transition – Generation Corporation Designated Rate Options ("TRO") expired on April 30, 2006, volumes sold under such options were also excluded from the revenue limit rebate. The revenue limit, which was originally established for a period of 13 months ending April 30, 2006, was subsequently extended for an additional three years. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh. On May 1, 2007, the revenue limit will return to 4.7¢/kWh and increase to 4.8¢/kWh effective May 1, 2008. In addition, beginning April 2006, volumes sold under a Pilot Auction administered by the Ontario Power Authority ("OPA") are subject to a revenue limit that is 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Revenues above these limits are returned to the Independent Electricity System Operator ("IESO") for the benefit of consumers.

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, replaced OPG's rebate obligations under the Market Power Mitigation Agreement effective April 1, 2005.

From 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 continued 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 terawatt hours ("TWh") on an annual basis.

Revenue from OPG's nuclear generating stations is favourably impacted by the introduction of regulated prices that reflect the projected production and costs of operations, including an allowed return on equity, and the corresponding elimination of the Market Power Mitigation Agreement rebate. Revenue from OPG's regulated hydroelectric generating stations is negatively impacted by the regulatory changes. While a significant portion of OPG's output from its unregulated assets is subject to the revenue limit, this limit is higher than the limit that was prescribed under the Market Power Mitigation Agreement.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. A detailed discussion of OPG's performance by reportable business segment is included under the heading, *Discussion of Operating Results by Business Segment*.

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Revenue				
Revenue before revenue limit and Market Power Mitigation Agreement rebates	**1,374**	1,514	**2,942**	3,284
Revenue limit rebate	**(29)**	(141)	**(89)**	(141)
Market Power Mitigation Agreement rebate	**-**	-	**-**	(412)
	1,345	1,373	**2,853**	2,731
Earnings				
Income before impairment of long-lived assets, income tax expenses (recovery) and extraordinary item	**146**	204	**440**	356
Impairment of long-lived assets	**-**	63	**-**	265
Income before income taxes and extraordinary item	**146**	141	**440**	91
Income tax expenses (recovery)	**3**	4	**98**	(8)
Income before extraordinary item	**143**	137	**342**	99
Extraordinary item	**-**	74	**-**	74
Net income	**143**	63	**342**	25
Electricity production (TWh)	**25.5**	25.5	**53.9**	54.3
Cash flow				
Cash flow (used in) provided by operating activities	**(435)**	73	**(1)**	373

Net income for the three months ended June 30, 2006 was $143 million compared to $63 million in the three months ended June 30, 2005, an increase of $80 million. Income before income taxes for the three months ended June 30, 2006 was $146 million compared to income before income taxes and the extraordinary item for the three months ended June 30, 2005 of $141 million, an increase of $5 million. During the second quarter of 2005, OPG recorded a one-time extraordinary loss of $74 million as a result of the adoption of rate regulated accounting for income taxes related to the rate regulated segments of the Company's business.

Net income for the six months ended June 30, 2006 was $342 million compared to $25 million during the same period in 2005, an increase of $317 million. Income before income taxes for the six months ended June 30, 2006 was $440 million compared to income before income taxes and the extraordinary item for the same period last year of $91 million, an increase of $349 million.

The following is a summary of the factors impacting OPG's results for the three and six months ended June 30, 2006 compared to results for the same periods in 2005, on a before-tax basis:

(millions of dollars – before tax)	**Three Months**	**Six Months**
Income before income taxes and extraordinary item for the periods ended June 30, 2005	**141**	**91**
Changes in gross margin		
(Decrease) increase in electricity sales prices after revenue limit and Market Power Mitigation Agreement rebates	(28)	104
Change in electricity generation by segment:		
Regulated – Nuclear	86	124
Regulated – Hydroelectric	(14)	(18)
Unregulated – Hydroelectric	(3)	18
Unregulated – Fossil-Fuelled	(49)	(92)
Other changes in gross margin	26	64
	18	200
Increase in pension and other post employment benefit costs	(44)	(89)
Amortization of Pickering A Return to Service deferral account balance	(5)	(15)
(Decrease) increase in earnings on nuclear fixed asset removal and nuclear waste management funds	(9)	9
Decrease in depreciation expense primarily due to extension of service lives of the Nanticoke station, Pickering B station and Unit 4 of the Pickering A station	12	29
Unrecoverable costs related to Thunder Bay gas conversion project	(13)	(13)
Other changes	(17)	(37)
(Decrease) increase in income before income taxes, excluding impairment of long-lived assets	**(58)**	**84**
Impairment of long-lived assets	63	265
Income before income taxes for the periods ended June 30, 2006	**146**	**440**

Earnings for the Three Months Ended June 30, 2006

Earnings for the three months ended June 30, 2006 were favourably impacted by an increase in gross margin from electricity sales primarily due to an increase in electricity generation from OPG's nuclear generating stations. This increase in gross margin was partially offset by lower average sales prices for electricity generation not receiving a fixed regulated price, due to lower Ontario spot market prices for the second quarter of 2006 compared to the same period in 2005.

Operations, maintenance and administration ("OM&A") expenses for the three months ended June 30, 2006 were $683 million compared to $616 million during the same period in 2005. The higher OM&A expenses were primarily due to an increase in pension and OPEB costs mainly due to changes in economic assumptions used to measure the costs. In 2006, OM&A expenses also included amortization of the Pickering A return to service costs, which were previously deferred in accordance with a regulation pursuant to the *Electricity Restructuring Act, 2004,* (Ontario). Amortization commenced late in 2005 with the return to service of Unit 1 at the Pickering nuclear generating station.

During the second quarter of 2005, the Company recorded an impairment charge of $63 million related to Units 2 and 3 of the Pickering A nuclear generating station, as a result of the Company's decision not to proceed with the return to service of these 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. The impairment charge represented the carrying value, including construction in progress of these two units.

During the second quarter of 2006, the federal government passed legislation which eliminated the Large Corporations Tax and reduced future income tax rates. These measures reduced income taxes for the three months ended June 30, 2006 by $31 million, compared to the same period in 2005.

Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes relating to the rate regulated segments of its business using the taxes payable method. Under this method, future income tax assets and liabilities associated with these segments are not recognized where those future income taxes are expected to be recovered in the regulated rates charged to customers in the future. As a result, OPG did not record a future tax expense of $8 million and $53 million for the rate regulated segments during the three months ended June 30, 2006 and June 30, 2005, respectively, which would have been recorded had OPG accounted for income taxes for the regulated segments using the liability method. In the second quarter of 2005, as part of the transition to rate regulated accounting, OPG eliminated a net future income tax asset balance of $74 million related to rate regulated segments and recorded a corresponding one-time extraordinary loss.

Earnings for the Six Months Ended June 30, 2006

Earnings for the six months ended June 30, 2006 were favourably impacted by an increase in gross margin from electricity sales due primarily to higher electricity generation from OPG's nuclear generating stations compared to the same period in 2005, and higher average sales prices with the introduction of regulated prices and other related regulatory changes effective April 1, 2005. This increase in gross margin was partially offset by lower average Ontario spot market prices compared to the same period of 2005, that impacted revenue from OPG's unregulated generating stations.

For the six months ended June 30, 2006, OM&A expenses were $1,333 million compared to $1,203 million during the same period in 2005. In 2006, pension and OPEB costs have increased significantly compared to the same period last year mainly due to changes in economic assumptions used to measure the costs. In addition, OM&A expenses included the amortization of a portion of the previously deferred Pickering A return to service costs.

OPG recorded an impairment charge of $202 million related to its Lennox generating station in the first quarter of 2005, which contributed to higher earnings in 2006 relative to 2005. It was determined that the Lennox generating station, as a relatively high variable cost plant, would not be able to recover its carrying value from the wholesale electricity market in the future. Earnings were also reduced in 2005 as a result of the impairment charge of $63 million related to Units 2 and 3 at the Pickering A nuclear generating station.

The recently passed legislation eliminating the Large Corporations Tax and reducing future income tax rates increased earnings by $33 million during the six months ended June 30, 2006 compared to the same period in 2005.

Net income during the six months ended June 30, 2006 reflected the impact of accounting for income taxes for the regulated segments of the business using the taxes payable method for the entire period. Net income for the six months ended June 30, 2005 reflected the impact the taxes payable method for only three months, as this method was adopted upon inception of rate regulation on April 1, 2005. For the six months ended June 30, 2006, OPG did not record a future tax expense of $18 million. Net income for the six months ended June 30, 2005 reflected the impact of not recording a future income tax expense of $53 million, and the related extraordinary loss of $74 million.

Average Sales Prices

The weighted average Ontario spot electricity market price and OPG's average sales prices by reportable business segment, net of the revenue limit rebate for the period from April 1, 2005 to June 30, 2006, and net of the Market Power Mitigation Agreement rebate up to the inception of rate regulation on April 1, 2005, were as follows:

	Three Months Ended June 30		**Six Months Ended June 30**	
(¢/kWh)	**2006**	**2005**	**2006**	**2005**
Weighted average hourly Ontario spot electricity market price	**4.8**	6.3	**5.0**	6.0
Regulated – Nuclear	**4.9**	4.9	**4.9**	4.6
Regulated – Hydroelectric [1]	**3.4**	3.9	**3.5**	4.1
Unregulated – Hydroelectric [2]	**4.6**	5.1	**4.7**	4.8
Unregulated – Fossil-Fuelled [2]	**4.7**	5.5	**4.8**	4.9
OPG's average sales price	**4.6**	4.9	**4.6**	4.6

1 During the period from April 1, 2005 to June 30, 2006, electricity generated from stations in the Regulated-Hydroelectric segment received a fixed price of 3.3¢/kWh for the first 1,900 MWh of generation in any hour, and the Ontario spot electricity market price for generation above this level.

2 During the period from April 1, 2005 to April 30, 2006, 85 per cent of the electricity generated 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. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh.

OPG's average sales price for the three months ended June 30, 2006 was 4.6¢/kWh compared to 4.9¢/kWh for the same period in 2005. The decrease was primarily due to lower Ontario spot electricity prices during the second quarter of 2006. Spot market prices were lower partly as a result of a decrease in demand reflecting more moderate temperatures during the second quarter of 2006 compared to the same period last year. As well, an increase in production from low marginal cost generation in Ontario contributed to the lower Ontario spot market prices.

OPG's average sales price for the six months ended June 30, 2006 and 2005 was 4.6¢/kWh. The increase in OPG's average sales price due to the introduction of regulated prices and other related regulatory changes effective April 1, 2005, was offset by lower Ontario spot market prices.

As a result of regulated prices and the revenue limit rebate, OPG's average sales price continued to be lower than the weighted average hourly Ontario spot electricity market price.

Electricity Generation

Total electricity generation during the three months ended June 30, 2006 and 2005 from OPG's generating stations was 25.5 TWh. For the six months ended June 30, 2006, total electricity generation from OPG's generating stations was 53.9 TWh compared to 54.3 TWh during the same period in 2005. An increase in generation from nuclear generating stations primarily as a result of the return to service of Unit 1 at the Pickering A generating station, was offset by lower fossil-fuelled generation due to lower electricity demand in Ontario. During the second quarter of 2005, Unit 4 at the Pickering A nuclear generating station was shut down for the duration of the quarter due to the inspection and repair of feeder pipes.

OPG's results are impacted by changes in demand resulting from variations in seasonal weather conditions. The following table provides a comparison of Heating and Cooling Degree Days for the three and six months ended June 30:

	Three Months Ended June 30		Six Months Ended June 30	
	2006	**2005**	**2006**	**2005**
Heating Degree Days [1]				
Period	**441**	493	**2,105**	2,470
Ten-year average	**500**	517	**2,328**	2,387
Cooling Degree Days [2]				
Period	**100**	152	**100**	152
Ten-year average	**90**	85	**90**	85

1 Heating Degree Days are recorded on days with an average temperature below 18^0C, and represent the aggregate of the differences between the average temperature and 18^0C for each day during the period, as measured at Pearson International Airport.

2 Cooling Degree Days are recorded on days with an average temperature above 18^0C, and represent the aggregate of the differences between the average temperature and 18^0C for each day during the period, as measured at Pearson International Airport.

Heating Degree Days for the three and six months ended June 30, 2006 decreased compared to the same period in 2005 due primarily to warmer weather during the winter of 2006 and early spring, compared to the same period in 2005. The reduction in heating degree days contributed to the decrease in Ontario's total electricity demand in 2006 compared to 2005.

Cooling Degree Days for the three months ended June 30, 2006 also decreased compared to the same period in 2005. Record high temperatures in June of 2005 contributed to an increase in total demand for electricity in Ontario last year.

Cash Flow from Operations

Cash flow used in operating activities for the three months ended June 30, 2006 was $435 million compared to cash flow provided by operating activities of $73 million during the same period in 2005. The decrease in cash flow from operating activities was mainly due to a higher payment to the IESO with respect to the revenue limit rebate during the second quarter of 2006, compared to the amount of the payment of the Market Power Mitigation Agreement rebate during the same quarter in 2005, increased contributions to the pension fund, and a decrease in revenue before the revenue limit rebate due to lower Ontario spot electricity market prices during the second quarter of 2006.

Cash flow used in operating activities for the six months ended June 30, 2006 was $1 million compared to cash flow provided by operating activities of $373 million during six months ended June 30, 2005. The decrease in cash flow provided by operating activities was mainly due to the higher revenue limit rebate payment during the second quarter of 2006, compared to the amount of the Market Power Mitigation Agreement rebate payments during the first six months of 2005, increased expenditures on fixed asset removal and nuclear waste management, increased contributions to the pension fund, and a decrease in revenue before rebates, partially offset by higher net income after adjustments for non-cash items.

The revenue limit rebate for the four months ended April 30, 2006 will be settled in August 2006. A subsequent settlement will be in November 2006 for the three months ended July 31, 2006. Settlements thereafter will be every three months for each three month period until April 30, 2009.

Recent Developments

Ontario's Electricity Future

In June 2006, the Minister of Energy directed the Ontario Power Authority ("OPA") to proceed with its recommended 20-year electricity supply mix plan, with some revisions. The revised plan includes maintaining nuclear generating capacity at its existing level of installed capacity through a combination of refurbishing existing nuclear generating units and beginning the approvals process for the construction of new nuclear generating units at an existing nuclear facility, increasing renewable sources of energy, enhancing conservation initiatives, and expanding the transmission capacity from Bruce County and the surrounding area.

Also in June 2006, OPG received a Shareholder Declaration from the Province instructing OPG to begin feasibility studies on refurbishing its existing nuclear generating units. The study will include a review of the economic, technological and environmental aspects of refurbishing OPG's nuclear generating units. As part of this initiative, OPG will begin an environmental assessment on the refurbishment of the four existing units at the Pickering B generating station. OPG was also instructed to begin a federal approvals process, including an environmental assessment, for the construction of new nuclear generating units at an existing nuclear facility.

In its semi-annual Ontario Reliability Outlook released in June 2006, the Independent Electricity System Operator ("IESO") indicated that changes were needed to its planning assumptions as a result of the growing impacts that summer weather puts on demand and resources. The result of the change in planning assumptions is a 2,500 to 3,000 MW overall increase to forecast resource requirements over that previously identified. As a result of additional capacity requirements in order to maintain system reliability, the Ministry of Energy announced that further delays will be necessary in the Province's plan to replace coal-fired generation by 2009. The Minister has since directed the OPA to determine how best to replace coal-fired generation and the earliest time frame in which it can be achieved. The OPA is also being asked to recommend options for cost-effective measures to reduce air emissions from coal-fired generation.

As a result of the delays in the Province's plan to replace coal-fired generation, OPG has extended the service life for all of the coal-fired generating stations for purposes of calculating depreciation. Details of this change are provided in the discussion of depreciation and amortization for the Unregulated Fossil-Fuelled Segment in the MD&A.

Ontario's Integrated Power System Plan

Subsequent to the directive to the OPA by the Minister of Energy, the OPA published in June 2006, a report titled "Ontario's Integrated Power System Plan – Scope and Overview". The Integrated Power System Plan ("IPSP") will be a comprehensive 20-year plan for Ontario's electricity system that will identify the conservation, generation, and transmission investments that are needed in the next three to five years, indicate the preparatory work required for the subsequent five years, and chart broad directions for the development of the system in the balance of the planning period. The IPSP will reflect the electricity sector goals set by the Province and will include programs and activities that respond to the Minister of Energy's directive to the OPA earlier in June. The IPSP will be subject to an independent regulatory review by the OEB and is expected to be submitted to the OEB in March 2007.

Pickering A Nuclear Generating Station – Safe Storage

Following OPG's decision in 2005 not to proceed with the refurbishment of Units 2 and 3 at the Pickering A nuclear generating station, OPG initiated a process to remove the nuclear fuel and heavy water from the units, and place the units in a safe storage state. OPG is in the process of defining the scope, completing design engineering packages, and finalizing the cost and schedule for the project. This work is expected to take approximately three years to complete. Once complete, OPG will request amendments to the Pickering A generating station Operating License to reflect the safe storage state of Units 2 and 3.

Thunder Bay Generating Station

In October 2005, OPG received a Shareholder Declaration and a Shareholder Resolution from the Province instructing OPG's Board of Directors to convert the Thunder Bay generating station to run on natural gas. Under the Shareholder Resolution, the Province indicated that it would put in place appropriate cost recovery mechanisms covering initial capital and development expenditures, ongoing operating costs and an appropriate return to OPG. The cost recovery mechanisms were required to ensure that OPG was able to record the conversion costs as an asset. In light of the directive to the OPA to determine how best to replace coal-fired generation, the Province determined that it was no longer advisable to continue with the conversion of the Thunder Bay generating station to run on natural gas. On July 12, 2006, OPG received a Shareholder Declaration revoking the October 2005 Shareholder Declaration, effectively cancelling the project. As a result, OPG recognized a loss of $13 million for costs incurred on the conversion project.

VISION, CORE BUSINESS AND STRATEGY

OPG's mandate is to cost effectively produce electricity from its diversified generating assets, while operating in a safe, open and environmentally responsible manner. OPG and its sole Shareholder, the Province, reached agreement on this mandate during the third quarter of 2005. OPG's mandate, as well as a discussion of strategies to accomplish the mandate, is outlined in the 2005 annual MD&A under the heading, *Vision, Core Business and Strategy*.

Improving the Performance of Generating Assets

Nuclear Generating Assets

OPG's strategic objective is to operate the Darlington and Pickering A and B nuclear generating stations in a safe, efficient and cost effective manner, while undertaking prudent investments to improve their reliability and predictability. To achieve this objective, programs and initiatives have been implemented to improve safety performance, reduce forced outages through improvements in equipment reliability, optimize planned outages, reduce maintenance backlogs, mitigate technological risks through comprehensive inspection and testing programs, focus on production unit energy costs, and address resource planning issues.

Pursuant to the direction from the Minister of Energy, OPG is undertaking a feasibility study on the refurbishment of its Pickering B and Darlington nuclear facilities. The project's mandate is to: complete a plant condition assessment for each facility; develop and confirm whether there is a business case for refurbishment; establish a refurbishment scope, cost estimate and preliminary project schedule; work with the industry to develop a project infrastructure and the capability to execute requisite work; and if there is a decision to move forward, complete the environmental assessments and meet the requirements of the Canadian Nuclear Safety Commission ("CNSC") for life extension considerations.

Hydroelectric Generating Assets

OPG's strategic objective is to improve production from its existing hydroelectric generating assets in a cost effective and efficient manner. Programs are continuing at several stations: to replace aging and obsolete equipment, accelerate runner upgrades, and improve availability through enhanced maintenance practices. During the six months ended June 30, 2006, OPG completed runner upgrades at three unregulated hydroelectric generating stations which resulted in 15 MW of additional capacity. In addition, plans are being developed for approval of the conversion of Sir Adam Beck 1, Unit 7 from a 25 to 60 cycle load requirement. The conversion would increase capacity by an estimated additional 7 MW, and be in-service for early 2009.

Fossil-Fuelled Generating Assets

OPG's strategic objective, taking into account the Province's coal replacement policy, is to maintain the productive capability of its coal-fired generating facilities, while continuing to operate them in an environmentally responsible manner. To achieve this objective, programs and initiatives are in place to:

address the impacts of increased unit starts and stops, in part due to the role that the fossil-fuelled plants perform as intermediate and peaking facilities, ensure continued environmental compliance, and retain competent staff to continue to operate the units until their closure.

Increasing OPG's Generating Capacity

OPG's strategy with respect to increasing its generating capacity is to expand, develop, and/or improve its hydroelectric generating capacity through expansion and redevelopment of its existing sites, as well as the pursuit of new projects where feasible. OPG will undertake these investments on its own or through partnerships.

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 Sir Adam Beck generating facilities to utilize available water more effectively, and is expected to increase annual generation on average by about 1.6 TWh.

OPG has entered into a contract for the design and construction of the 10.4 kilometre tunnel and associated facilities. The value of the design-build contract is approximately $600 million, with the total project expected to cost approximately $985 million. The project is financed through the Ontario Electricity Financial Corporation ("OEFC").

Capital project expenditures for the three months ended June 30, 2006 were $34 million and life-to-date capital expenditures were $149 million. Site preparation work started in September 2005. Outlet canal excavation was completed in April 2006. In-water construction activities at the intake area started in April 2006. On-site assembly of the tunnel boring machine started in May 2006 and is expected to continue into August 2006. The project is currently on schedule and within the expected cost estimate. Project completion is expected by late 2009.

Lac Seul

In December 2005, OPG's Board of Directors approved a $47 million project to construct a new 12.5 MW hydroelectric generating station on the English River. The new Lac Seul generating station will utilize a majority of the spill currently passing the existing Ear Falls generating station, thus increasing the overall efficiency, capacity and energy generated from this location. A design-build contract was awarded and construction started during the first quarter of 2006, with the in-service date planned for the fourth quarter of 2007.

Work is progressing on the water conveyance tunnel and the intake coffer dam. Capital project expenditures for the three months ended June 30, 2006 were approximately $6 million and life-to-date capital expenditures were $13 million.

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 IESO identified, in its December 2005 18-Month Outlook, that Toronto faces rotating blackouts within the next two years unless urgent action is taken to install new power generation.

During the first quarter of 2006, to address the urgent energy needs of downtown Toronto, the Province directed the OPA to negotiate an agreement with PEC, with the objective of developing the 550 MW Portlands Energy Centre. The OPA has provided interim financial guarantees for costs required to expedite the project prior to signing a definitive contract. PEC is continuing to negotiate a engineer-procure-construct contract for the facility with SNC Lavalin Power Ontario, and has entered into an agreement with this firm to cover the preliminary engineering, procurement, and early site work.

Capital project expenditures for the three months ended June 30, 2006 were approximately $13 million and life-to-date capital expenditures were $23 million.

Lower Mattagami

In May, 2006, OPG provided development alternatives to increase the generating capacity of four hydroelectric generating stations on the Lower Mattagami River to the Province. The incremental capacity associated with these alternatives ranged from approximately 140 to 450 MW.

In May 2006, OPG received a letter from the Minister of Energy, which directed OPG to proceed immediately with the definition phase for a 450 MW development which includes the replacement of the Smoky Falls generating station and the expansion of Little Long, Harmon and Kipling generating stations, all of which are located on the Lower Mattagami River. OPG was also directed to initiate discussions with Ministry staff on a power purchase agreement.

Lakeview Site

OPG is continuing with decommissioning and demolishing of the Lakeview coal-fired generating station, having closed the station last year after more than 40 years of service. OPG has recently signed a memorandum of agreement with Enersource Hydro Mississauga Services Inc. and BPC Energy Corporation, to explore the potential development of a gas-fuelled electricity generating station at the site. The construction of a new plant would proceed only after required approvals and successful completion of negotiations with the OPA.

ONTARIO ELECTRICITY MARKET TRENDS

Ontario's electricity demand averaged approximately 16,475 MW during the second quarter of 2006 compared to approximately 16,974 MW during the same period of 2005. For the six months ended June 30, 2006, Ontario electricity demand averaged 17,345 MW compared to 17,937 MW for the six months ended June 30, 2005. In its 18-Month Outlook published on June 23, 2006, the IESO has forecast that the summer 2006 Monthly Normal peak demand is expected to be slightly below 25,400 MW, while the Monthly Normal winter 2006-07 peak demand is forecast to be slightly below 24,800 MW. The IESO forecasts that energy consumed is expected to be 155.5 TWh in 2006, an increase of 0.5 per cent over the weather corrected energy demand of 154.7 TWh in 2005. For 2007, energy consumed is forecast to be 158.1 TWh, an increase of 1.7 per cent over 2006.

The IESO initiated a Day-Ahead Commitment Process (“DACP”), which is intended to address reliability needs in Ontario’s power system in 2006. The DACP was established effective May 31, 2006, and is anticipated to continue to November 30, 2006. In addition, the IESO has initiated an Emergency Load Reduction Program to provide consumers with incentives to reduce their electricity consumption. This program started on June 20, 2006.

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 its business segments.

With the introduction of rate regulation, OPG revised its reportable business segments to separately reflect the regulated and unregulated aspects of its business. Since the second quarter of 2005, OPG reported its business segments as Regulated – Nuclear, Regulated – Hydroelectric, and Unregulated Generation. Beginning in the first quarter of 2006, OPG separated the Unregulated Generation business segment into two reportable segments identified as Unregulated – Fossil-Fuelled and Unregulated – Hydroelectric, as a result of changes in the management structure of these segments. Results for the comparative periods were reclassified to reflect the revised disclosure.

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 – Hydroelectric and Unregulated – Fossil-Fuelled generation segments after that date. Gains or losses in these hedging transactions are recognized in revenue over the terms 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. This business segment also includes revenue under the terms of a lease arrangement with Bruce Power related to the Bruce nuclear generating stations. This arrangement includes lease revenue and revenue from engineering analysis and design, technical and other services. Revenue is also earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control/reactive support.

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 is comprised of 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 related to these stations 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 – Hydroelectric Segment

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its hydroelectric generating stations that are not subject to rate regulation. The Unregulated – 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, and revenues from other services.

Unregulated – Fossil-Fuelled Segment

The Unregulated – Fossil-Fuelled business segment operates in Ontario, generating and selling electricity from its fossil-fuelled generating stations, which are not subject to rate regulation. The Unregulated – Fossil-Fuelled 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, automatic generation control, 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"). The revenue and expenses related to OPG's trading and other non-hedging activities are also 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. In addition, the Other category includes revenue from real estate rentals.

KEY GENERATION AND FINANCIAL PERFORMANCE INDICATORS

Key performance indicators that directly pertain to OPG's mandate and corporate strategies are measures of production efficiency, cost effectiveness, and environmental performance. OPG evaluates the performance of its generating stations using a number of key performance indicators, which vary depending on the generating technology. These indicators are defined in this section and are discussed in the *Discussion of Operating Results by Business Segment* section.

Nuclear Unit Capability Factor

OPG's nuclear stations operate as baseload facilities as they have low marginal costs and are not designed for fluctuating production levels to meet peaking demand. The nuclear unit capability factor is a key measure of nuclear station performance. It is the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints 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. Capability factors are primarily impacted by planned and unplanned outages.

Fossil-Fuelled and Hydroelectric Equivalent Forced Outage Rate ("EFOR")

OPG's 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. OPG's hydroelectric stations operate primarily as baseload facilities and provide a reliable and low-cost source of renewable energy. A key measure of the reliability of the fossil-fuelled and hydroelectric stations is their ability to be available to produce electricity when called upon. EFOR is 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.

Hydroelectric Availability

Hydroelectric availability is a measure of the reliability of a hydroelectric generating unit represented by the percentage of time the generating unit is capable of providing service, whether or not it is actually in-service, compared to the total time for a respective period.

Nuclear Production Unit Energy Cost ("PUEC")

Nuclear PUEC is used to measure the operations-related costs of production of OPG's nuclear generating assets. Nuclear PUEC is defined as nuclear fuel, OM&A expenses including allocated corporate costs, and variable costs related to used fuel disposal and the disposal of low and intermediate level radioactive waste materials, divided by total energy produced.

Hydroelectric OM&A Expense per MWh

Hydroelectric OM&A expense per MWh is used to measure the cost effectiveness of the hydroelectric generating stations. It is defined as total hydroelectric OM&A expenses, including allocated corporate costs, divided by hydroelectric electricity generation.

Fossil-Fuelled OM&A Expense per MW

Since fossil-fuelled generating stations are primarily employed during periods of intermediate and peak demand, the cost effectiveness of these stations is measured by their total OM&A expenses, including allocated corporate costs, divided by total station nameplate capacity.

Other Key Indicators

In addition to performance and cost effectiveness indicators, OPG has identified certain environmental indicators. These indicators are discussed under the heading, *Risk Management*.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

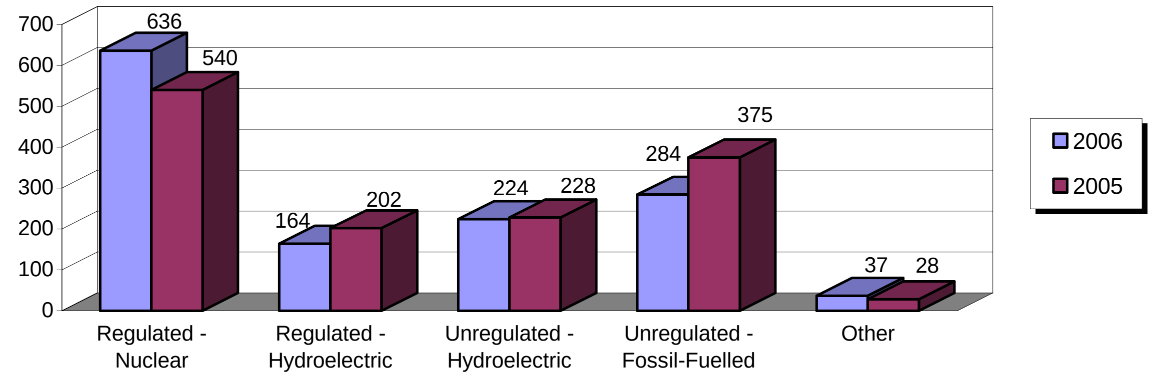
This section summarizes OPG's key results by segment for the three and six months ended June 30, 2006 and 2005. Although the regulations pursuant to the *Electricity Restructuring Act, 2004,* (Ontario), became effective commencing April 1, 2005, results for the first quarter of 2005 and the six months ended June 30, 2005 were reclassified according to the business segment definitions. The operating results for the first quarter of 2005 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 key generation and financial performance indicators by business segment:

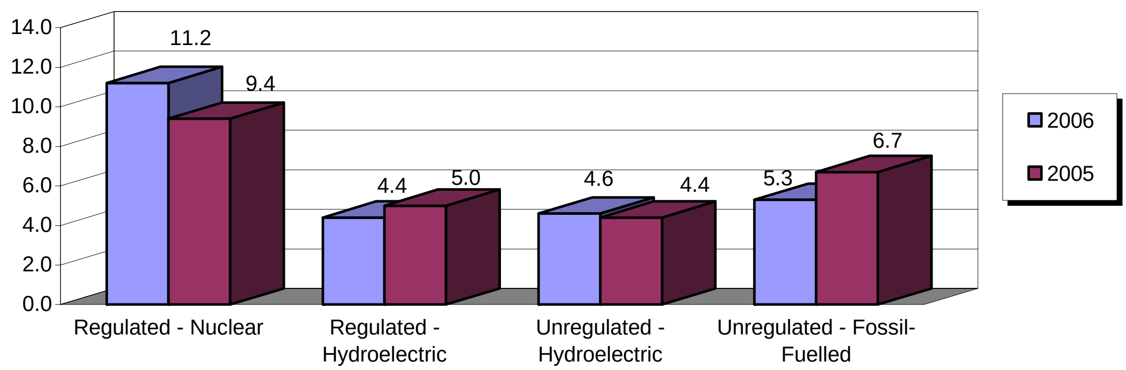
	Three Months Ended June 30		**Six Months Ended June 30**	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Revenue, net of revenue limit and Market Power Mitigation Agreement rebates				
Regulated – Nuclear	**636**	540	**1,345**	1,120
Regulated – Hydroelectric	**164**	202	**339**	407
Unregulated – Hydroelectric	**224**	228	**428**	401
Unregulated – Fossil-Fuelled	**284**	375	**665**	756
Other	**37**	28	**76**	47
	1,345	1,373	**2,853**	2,731
Income (loss) before interest, income taxes and extraordinary item				
Regulated – Nuclear	**18**	(99)	**92**	(115)
Regulated – Hydroelectric	**61**	94	**142**	206
Unregulated – Hydroelectric	**135**	149	**263**	255
Unregulated – Fossil-Fuelled	**(43)**	32	**(9)**	(171)
Other	**24**	12	**50**	10
	195	188	**538**	185
Electricity Generation (TWh)				
Regulated – Nuclear	**11.2**	9.4	**23.9**	21.4
Regulated – Hydroelectric	**4.4**	5.0	**8.9**	9.6
Unregulated – Hydroelectric	**4.6**	4.4	**8.8**	8.2
Unregulated – Fossil-Fuelled	**5.3**	6.7	**12.3**	15.1
Total electricity generation	**25.5**	25.5	**53.9**	54.3
Nuclear unit capability factor [1] *(per cent)*				
Darlington	**80.2**	80.4	**87.4**	87.1
Pickering A	**84.3**	1.9	**87.8**	50.6
Pickering B	**71.6**	72.9	**75.1**	78.6
Equivalent forced outage rate (per cent)				
Regulated – Hydroelectric	**1.0**	0.5	**0.7**	0.6
Unregulated – Hydroelectric	**1.2**	1.5	**1.2**	1.3
Unregulated – Fossil-Fuelled	**15.7**	16.8	**12.9**	16.1
Availability (per cent)				
Regulated – Hydroelectric	**90.5**	91.9	**91.6**	92.2
Unregulated – Hydroelectric	**95.4**	96.2	**94.8**	95.2
Nuclear PUEC ($/MWh)	**43.91**	48.31	**40.90**	41.58
Regulated – Hydroelectric OM&A expense per MWh ($/MWh)	**5.23**	3.60	**4.94**	3.75
Unregulated – Hydroelectric OM&A expense per MWh ($/MWh)	**9.78**	7.73	**9.20**	7.80
Unregulated – Fossil-Fuelled OM&A expense per MW ($000/MW)	**66.5**	49.2	**60.6**	46.9

[1] Capability factors by industry definition exclude grid-related unavailability.

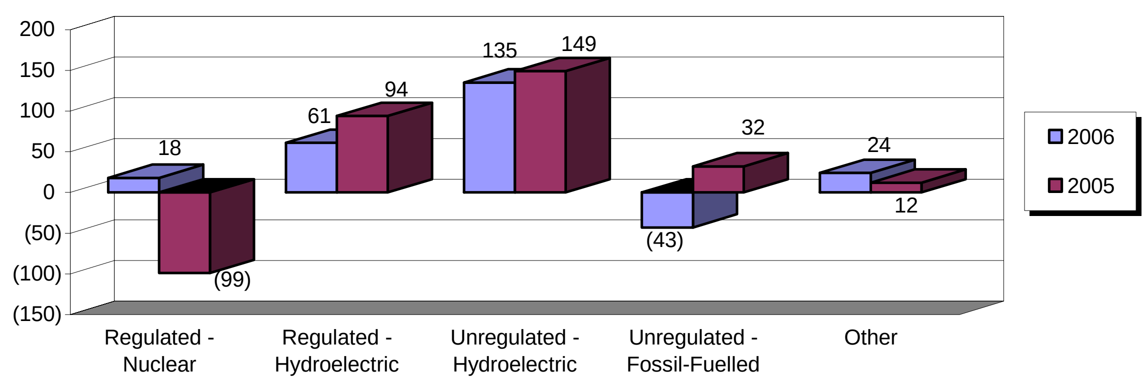
Revenue, Net of Revenue Limit Rebate by Segment
Three Months Ended June 30
(millions of dollars)



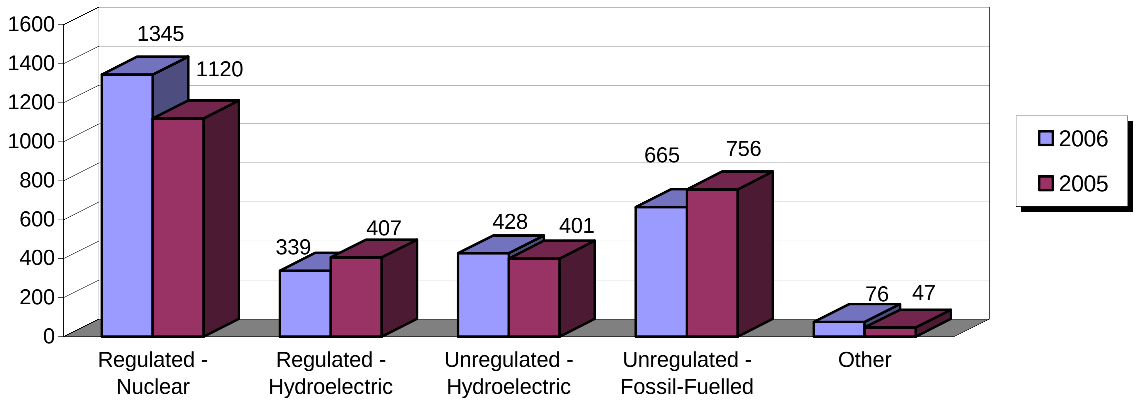
Electricity Production
Three Months Ended June 30
(TWh)



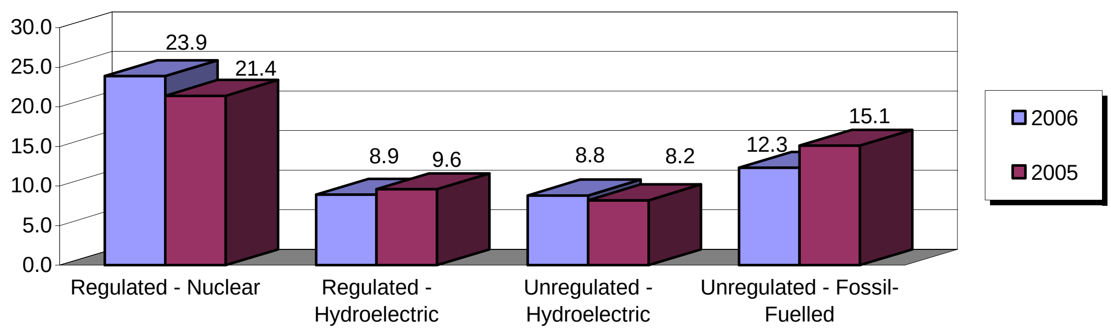
Income (Loss) Before Interest, Income Taxes and Extraordinary Item by Segment
Three Months Ended June 30
(millions of dollars)



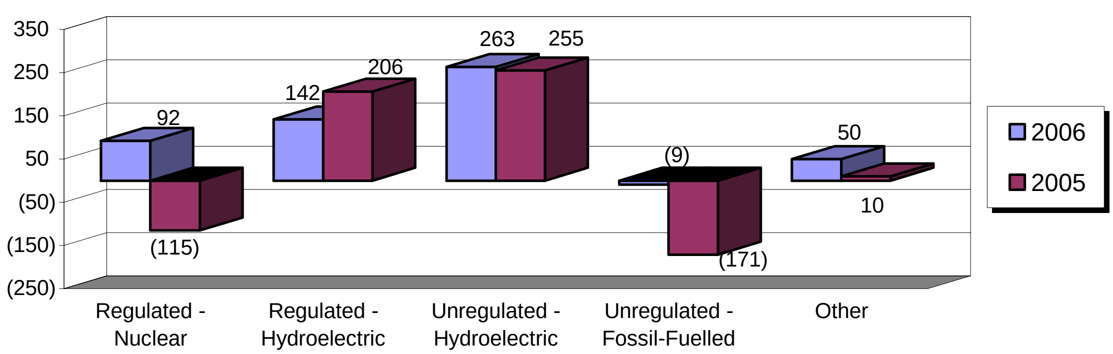
Revenue, Net of Revenue Limit and Market Power Mitigation Agreement Rebates by Segment
Six Months Ended June 30
(millions of dollars)



Electricity Production
Six Months Ended June 30
(TWh)



Income (Loss) Before Interest, Income Taxes and Extraordinary Item by Segment
Six Months Ended June 30
(millions of dollars)



Regulated – Nuclear Segment

(millions of dollars)	Three Months Ended June 30 2006	2005	Six Months Ended June 30 2006	2005
Revenue net of Market Power Mitigation Agreement rebate	**636**	540	**1,345**	1,120
Fuel expense	**28**	25	**59**	54
Gross margin	**608**	515	**1,286**	1,066
Operations, maintenance and administration	**478**	446	**953**	867
Depreciation and amortization	**84**	90	**169**	179
Accretion on fixed asset removal and nuclear waste management liabilities	**122**	117	**245**	234
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(103)**	(112)	**(192)**	(183)
Property and capital taxes	**9**	10	**19**	21
Income (loss) before impairment of long-lived asset	**18**	(36)	**92**	(52)
Impairment of long-lived asset	**-**	63	**-**	63
Income (loss) before interest and income taxes	**18**	(99)	**92**	(115)

Revenue

(millions of dollars)	Three Months Ended June 30 2006	2005	Six Months Ended June 30 2006	2005
Regulated generation sales	**550**	461	**1,175**	461
Spot market sales, net of hedging instruments	**-**	-	**-**	662
Market Power Mitigation Agreement rebate	**-**	-	**-**	(160)
Other	**86**	79	**170**	157
Total revenue	**636**	540	**1,345**	1,120

Regulated – Nuclear revenue was $636 million for the three months ended June 30, 2006 compared to $540 million during the same period in 2005, an increase of $96 million or 18 per cent. The increase in revenue was primarily due to higher electricity generation of 1.8 TWh compared to the same period in 2005.

Regulated – Nuclear revenue was $1,345 million for the six months ended June 30, 2006 compared to $1,120 million during the same period in 2005. The increase in revenue of $225 million was largely due to higher electricity generation during the first six months of 2006 compared to the same period last year. In addition, higher sales prices related to the introduction of regulated rates effective April 1, 2005 contributed to the increase in revenue for the six months ended June 30, 2006 compared to the same period in 2005.

Electricity Prices

Electricity generation from stations in the Regulated – Nuclear segment received a fixed price of 4.95¢/kWh since the introduction of rate regulation effective April 1, 2005. For the six months ended June 30, 2005, OPG's average sales price was 4.6¢/kWh, after taking into account the regulated rate for the second quarter of 2005 and OPG's average spot market sales price, net of the Market Power Mitigation Agreement rebate for the first quarter of 2005.

Volume

Electricity generation from stations in the Regulated – Nuclear segment for the three months ended June 30, 2006 was 11.2 TWh compared to 9.4 TWh for the same period in 2005. The increase in volume was mainly due to the return to service of Unit 1 at the Pickering A nuclear generating station in the fourth quarter of 2005. Also, in the second quarter of 2005, Unit 4 at the Pickering A nuclear generating station was shut down for the duration of the quarter due to the inspection and repair of feeder pipes.

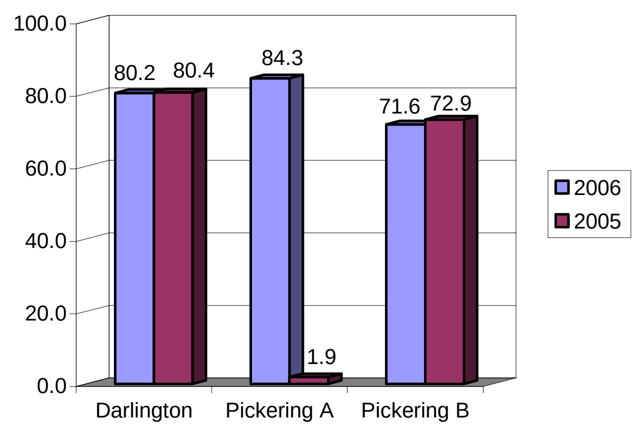
Total nuclear generation for the six months ended June 30, 2006 increased to 23.9 TWh from 21.4 TWh for the same period in 2005. The increase in volume was mainly due to the return to service of Unit 1 at the Pickering A nuclear generating station, and the impact in 2005 of the shut down of Unit 4 related to the feeder pipes.

The Darlington nuclear generating station's unit capability factor for the three months ended June 30, 2006 of 80.2 per cent was comparable to the 80.4 per cent capability factor for the same period in 2005.

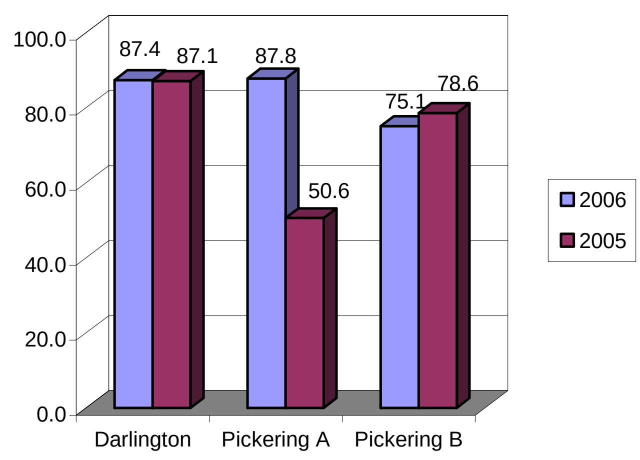
The Pickering A nuclear generating station's unit capability factor was 84.3 per cent for the three months ended June 30, 2006, and 1.9 per cent for the same period in 2005. The low capability factor in 2005 related to the shut down of Unit 4 due to inspection and repair of feeder pipes.

The Pickering B nuclear generating station's unit capability factor was 71.6 per cent for the three months ended June 30, 2006, down from 72.9 per cent during the same period in 2005. The decrease was primarily due to slightly higher planned outage days.

Nuclear Unit Capability Factor
Three Months Ended June 30
(%)



Nuclear Unit Capability Factor
Six Months Ended June 30
(%)



For the six months ended June 30, 2006, the unit capability factor for the Darlington nuclear generating station was 87.4 per cent, which was comparable to 87.1 per cent for the six months ended June 30, 2005.

For the six months ended June 30, 2006, the Pickering A nuclear generating station's unit capability factor was 87.8 per cent compared to 50.6 per cent for the six months ended June 30, 2005. This reflected strong performance from the Pickering A generating station in 2006.

For the six months ended June 30, 2006, the Pickering B nuclear generating station's unit capability factor was 75.1 per cent compared to 78.6 per cent for the same period in 2005. The decrease was primarily due to higher planned outage days.

Fuel Expense

Fuel expense for the three months ended June 30, 2006 was $28 million compared to $25 million during the same period in 2005. Fuel expense for the six months ended June 30, 2006 was $59 million compared to $54 million during the same period in 2005. The increase in fuel expense during the second quarter of 2006 and the six months ended June 30, 2006 compared to the same periods in 2005 was primarily due to higher generation.

Operations, Maintenance and Administration

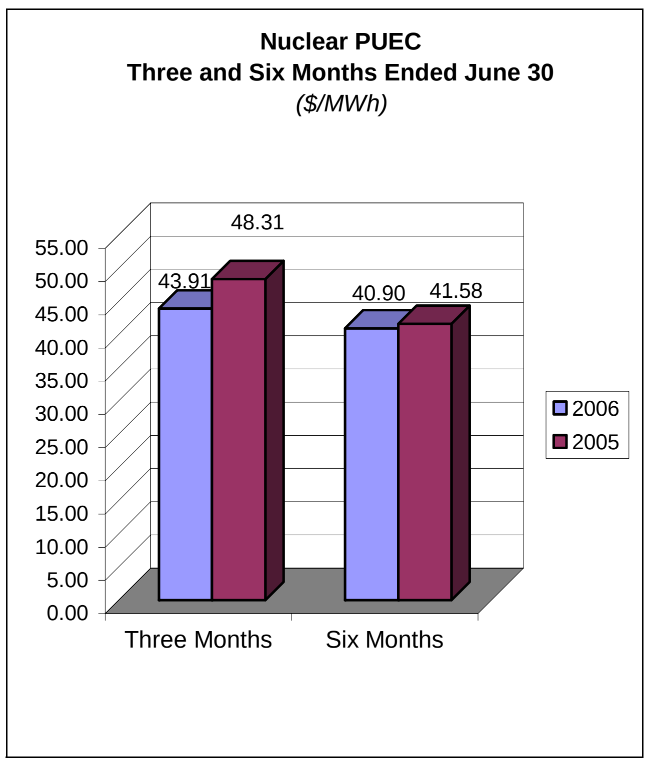
OM&A expenses for the three months ended June 30, 2006 were $478 million compared to $446 million during the same period in 2005. Pension and OPEB costs increased by $34 million, primarily due to changes in economic assumptions related to discount rates and inflation. In addition, OM&A expenses for the three months ended June 30, 2006 included amortization of $5 million related to Pickering A nuclear generating station return to service costs, which were previously deferred.

Effective January 1, 2005, in accordance with a regulation pursuant to the *Electricity Restructuring Act, 2004*, (Ontario), OPG established a balance sheet deferral account for non-capital costs associated with the return to service of Pickering A nuclear generating station units. The deferred costs are charged to operations in accordance with the terms of the regulation. Amortization of this deferral account commenced in the fourth quarter of 2005 following the return to commercial service of Unit 1 of the Pickering A nuclear generating station.

OM&A expenses were $953 million for the six months ended June 30, 2006 compared to $867 million for the same period in 2005. The increase of $86 million was primarily due to the increase in pension and OPEB costs of $67 million, and amortization of $15 million related to Pickering A nuclear generating station return to service costs.

Nuclear PUEC for the three months ended June 30, 2006 decreased to $43.91/MWh compared to $48.31/MWh during the same period in 2005. The decrease was primarily due to higher generation during the second quarter of 2006, partially offset by the impact of the higher pension and OPEB costs.

During the six months ended June 30, 2006, nuclear PUEC was $40.90/MWh compared to $41.58/MWh. The decrease was due to higher generation in 2006, partially offset by higher pension and OPEB costs.



Depreciation and Amortization

Depreciation and amortization expense for the three months ended June 30, 2006 was $84 million compared to $90 million for the same period in 2005. Depreciation and amortization expense for the six months ended June 30, 2006 was $169 million compared to $179 million for the same period last year. The decrease was primarily due to the impact of an extension of the remaining service lives of the Pickering B nuclear generating station and Unit 4 of the Pickering A nuclear generation station, for purposes of calculating depreciation. The reduction in depreciation related to the service life extension was partially offset by the impact of the return to commercial service of Unit 1 at the Pickering A station and fixed asset additions.

Accretion

Accretion expense relating to future costs for fixed asset removal and nuclear waste management was $122 million for the three months ended June 30, 2006 compared to $117 million during the second quarter of 2005. Accretion expense for the six months ended June 30, 2006 was $245 million compared to $234 million for the same period last year. The increase in the accretion expense in 2006 was due to the higher liability base compared to last year primarily as a result of the increase in the present value of the liability due to the passage of time.

Earnings on the Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

For the three months ended June 30, 2006, OPG realized earnings of $103 million on the nuclear fixed asset removal and nuclear waste management funds, compared to $112 million during the second quarter of 2005. Earnings on the Used Fuel Fund include a component based on the Ontario Consumer Price Index. The lower earnings in 2006 were primarily due to a decrease in Used Fuel Fund returns, due to a lower Ontario Consumer Price Index during the second quarter of 2006 compared to the same period in 2005. The Ontario Consumer Price Index is used to determine the guaranteed rate of return in the Used Fuel Fund.

For the six months ended June 30, 2006, OPG realized earnings of $192 million on the nuclear fixed asset removal and nuclear waste management funds, compared to $183 million during the same period of 2005. The increase of $9 million was due primarily to higher earnings from the Used Fuel Fund as a result of a larger asset base, partly offset by the impact on earnings of a lower Ontario Consumer Price Index.

Impairment of Long-lived Assets

During the three months ended June 30, 2005, OPG completed an assessment of the scope of the refurbishment work, the cost and the risks related to the return to service of Units 2 and 3 at the Pickering A nuclear generating station. 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, the Company recorded an impairment loss of $63 million related to the carrying amount of these two units, including construction in progress.

Regulated – Hydroelectric Segment

(millions of dollars)	Three Months Ended June 30 2006	Three Months Ended June 30 2005	Six Months Ended June 30 2006	Six Months Ended June 30 2005
Revenue, net of Market Power Mitigation Agreement rebate	**164**	202	**339**	407
Fuel expense	**60**	69	**112**	122
Gross margin	**104**	133	**227**	285
Operations, maintenance and administration	**23**	18	**44**	36
Depreciation and amortization	**17**	16	**33**	34
Property and capital taxes	**3**	5	**8**	9
Income before interest and income taxes	**61**	94	**142**	206

Revenue

(millions of dollars)	Three Months Ended June 30 2006	Three Months Ended June 30 2005	Six Months Ended June 30 2006	Six Months Ended June 30 2005
Regulated generation sales[1]	**141**	195	**304**	195
Spot market sales, net of hedging instruments	**-**	-	**-**	260
Market Power Mitigation Agreement rebate	**-**	-	**-**	(65)
Variance accounts	**(7)**	(4)	**(4)**	(4)
Other	**30**	11	**39**	21
Total revenue	**164**	202	**339**	407

[1] Regulated generation sales included revenue of $23 million and $69 million that OPG received at the Ontario spot market price for generation over 1,900 MWh in any hour during the second quarter of 2006 and 2005, respectively. Regulated generation sales included revenue of $69 million that OPG received at the Ontario spot market price for generation over 1,900 MWh in any hour during the six months ended June 30, 2006.

Regulated - Hydroelectric revenue was $164 million for the three months ended June 30, 2006 compared to $202 million during the same period in 2005. The decrease of $38 million was primarily due to a lower spot market price for generation in excess of 1,900 MWh in any hour and lower generation.

Regulated - Hydroelectric revenue was $339 million for the six months ended June 30, 2006 compared to $407 million during the same period in 2005. The decrease of $68 million was due to lower sales prices related to the introduction of regulated prices effective April 1, 2005, lower spot market prices during the second quarter of 2006 that impacted revenues in excess of 1,900 MWh in any hour, and lower electricity generation.

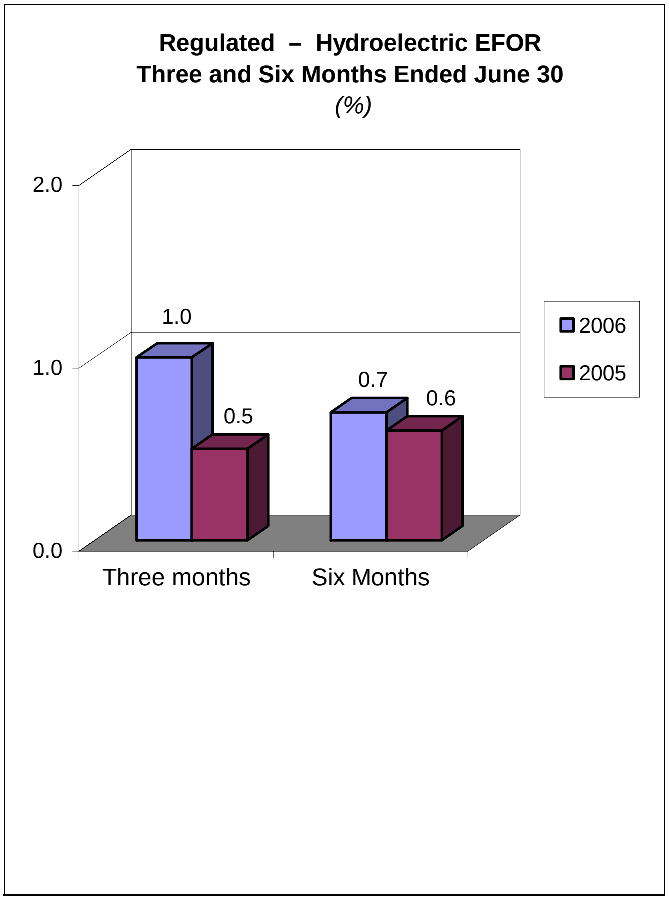
Electricity Prices

During the three months ended June 30, 2006, the average electricity sales price for the Regulated – Hydroelectric segment was 3.4¢/kWh compared to 3.9¢/kWh during the same period in 2005. The average sales price is based on the fixed price of 3.3¢/kWh for generation up to 1,900 MWh in any hour, and the spot electricity market price for generation above this level.

The average price for the six months ended June 30, 2006 was 3.5¢/kWh compared to 4.1¢/kWh for the six months ended June 30, 2005. The average price in 2005 reflects the regulated price for the second quarter and OPG's average spot market sales price net of the Market Power Mitigation Agreement rebate for the first quarter.

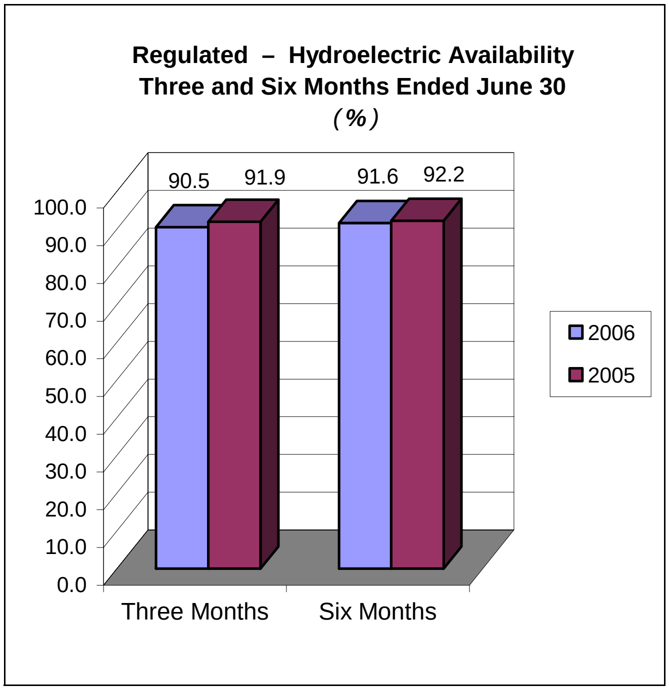
Volume

Electricity sales volume for the second quarter of 2006 was 4.4 TWh compared to 5.0 TWh for the second quarter of 2005. During the second quarter of 2006 and 2005, electricity generation of 0.7 TWh and 1.1 TWh, respectively, related to production levels above 1,900 MWh in any hour. Electricity sales volume for the six months ended June 30, 2006 was 8.9 TWh compared to 9.6 TWh during the same period in 2005. During the six months ended June 30, 2006, electricity generation of 1.6 TWh related to production levels above 1,900 MWh in any hour. The decrease in electricity sales volume in 2006 was primarily due to the lower water levels in the Niagara and St. Lawrence watersheds during the second quarter of 2006.



The equivalent forced outage rate for the Regulated – Hydroelectric stations was 1.0 per cent for the three months ended June 30, 2006 compared to 0.5 per cent during the same period in 2005. During the six months ended June 30, 2006, the equivalent forced outage rate for the Regulated – Hydroelectric stations was 0.7 per cent compared to 0.6 per cent during the same period in 2005. The EFOR reflects the continuing high reliability of these generating stations.

The availability for the Regulated – Hydroelectric stations was 90.5 per cent for the three months ended June 30, 2006 compared to 91.9 per cent in the second quarter of 2005. The lower availability in the second quarter of 2006 was primarily attributable to an increase in scheduled maintenance programs at certain generating stations.



During the six months ended June 30, 2006, availability for the Regulated – Hydroelectric stations was 91.6 per cent compared to 92.2 per cent during the same period in 2005. The lower availability relates primarily to the additional scheduled maintenance in 2006.

Variance Accounts

OPG is required under a regulation pursuant to the *Electricity Restructuring Act, 2004,* (Ontario), to establish variance accounts for the Regulated – Hydroelectric segment to capture the impact of differences in hydroelectric electricity production due to differences between forecast and actual water conditions and differences between forecast and actual ancillary revenues. During the three months ended June 30, 2006, OPG recorded a reduction in revenue of $13 million, as a result of higher ancillary revenues compared to those forecasted. During the three months ended June 30, 2006, OPG recorded revenue of $6 million, as a result of lower actual water conditions compared to those forecasted.

During the six months ended June 30, 2006, OPG recorded a reduction in revenue of $10 million, reflecting ancillary services revenue that was favourable compared to that forecasted for 2006. OPG recorded revenue of $6 million during the six months ended June 30, 2006 to reflect water conditions that were unfavourable compared to those forecasted for 2006.

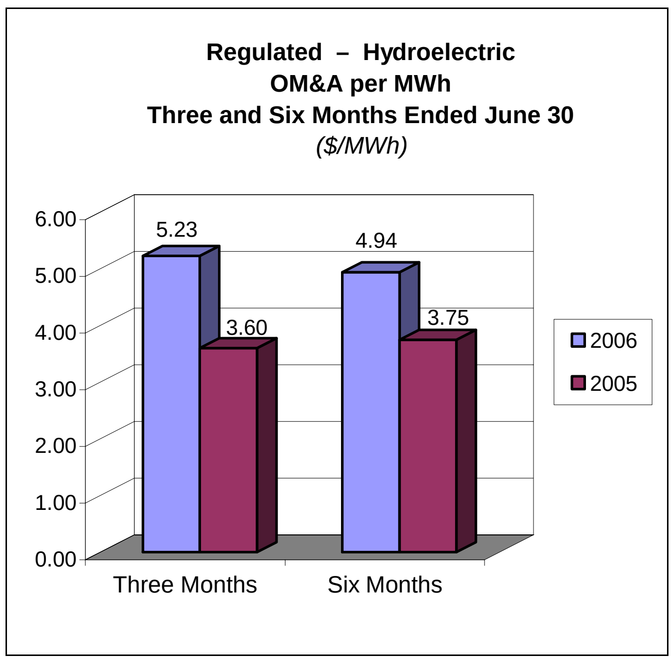
Fuel Expense

Fuel expense for the three months ended June 30, 2006 was $60 million compared to $69 million during the same period in 2005. Fuel expense for the six months ended June 30, 2006 was $112 million compared to $122 million for the six months ended June 30, 2005. 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. The decrease in fuel expense in 2006 compared to 2005 was due to lower generation volumes.

Operations, Maintenance and Administration

OM&A expenses for the three months ended June 30, 2006 were $23 million compared to $18 million during the second quarter of 2005. OM&A expenses for the six months ended June 30, 2006 were $44 million compared to $36 million during the same period in 2005. The increase in OM&A expenses in 2006 was mainly due to higher pension and OPEB costs.

OM&A expense per MWh for the regulated hydroelectric stations increased to $5.23/MWh in the second quarter of 2006 compared to $3.60/MWh for the same period in 2005. During the six months ended June 30, 2006, OM&A expense per MWh for the regulated hydroelectric stations was $4.94/MWh compared to $3.75 in the same period in 2005. The increase in 2006 compared to 2005 reflected higher OM&A expenses combined with lower generation.



Depreciation and Amortization

Depreciation expense for the three months ended June 30, 2006 was $17 million compared to $16 million in the same period in 2005. Depreciation expense for the six months ended June 30, 2006 was $33 million compared to $34 million during the same period last year.

Unregulated – Hydroelectric Segment

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Revenue, net of revenue limit and Market Power Mitigation Agreement rebates	**224**	228	**428**	401
Fuel expense	**25**	23	**45**	42
Gross margin	**199**	205	**383**	359
Operations, maintenance and administration	**45**	34	**81**	64
Depreciation and amortization	**16**	18	**32**	33
Property and capital taxes	**3**	4	**7**	7
Income before interest and income taxes	**135**	149	**263**	255

Revenue

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Spot market sales, net of hedging instruments	**221**	267	**440**	491
Revenue limit rebate	**(6)**	(51)	**(26)**	(51)
Market Power Mitigation Agreement rebate	**-**	-	**-**	(58)
Other	**9**	12	**14**	19
Total revenue	**224**	228	**428**	401

Unregulated - Hydroelectric revenue was $224 million for the three months ended June 30, 2006 compared to $228 million for the same period in 2005. The decrease of $4 million was primarily due to lower average sales prices, partially offset by the impact of higher electricity generation.

Unregulated - Hydroelectric revenue was $428 million for the six months ended June 30, 2006 compared to $401 million for the same period in 2005. The increase of $27 million was primarily due to higher electricity generation, which largely occurred during the first quarter of 2006 compared to 2005, partially offset by lower average sales prices.

Electricity Prices

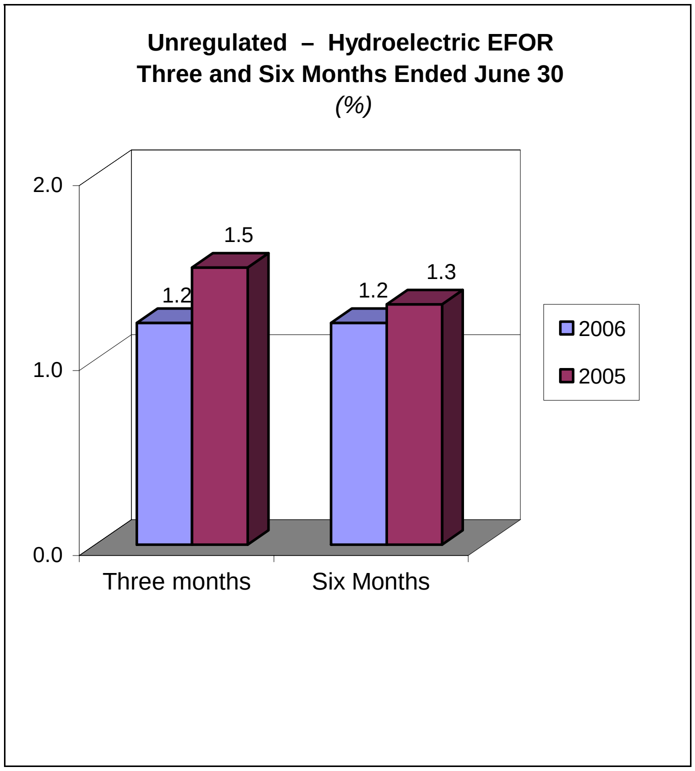
Eighty-five per cent of the generation output from OPG's unregulated generation assets, excluding the Lennox generating station, TRO volumes and forward sales as of January 1, 2005, was subject to the revenue limit based on an average price of 4.7¢/kWh commencing April 1, 2005. Effective May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh.

OPG's average sales price for its unregulated hydroelectric generation for the three months ended June 30, 2006 was 4.6¢/kWh compared to 5.1¢/kWh for the same period in 2005, after taking into account the revenue limit rebate. The decrease in OPG's average sales price was due primarily to lower average Ontario spot market prices.

OPG's average sales price for its unregulated hydroelectric generation for the six months ended June 30, 2006 was 4.7¢/kWh compared to 4.8¢/kWh in 2005. The decrease was primarily due to lower average Ontario spot market prices, largely offset by the impact of the replacement of the Market Power Mitigation Agreement rebate with the revenue limit rebate effective in the second quarter of 2005.

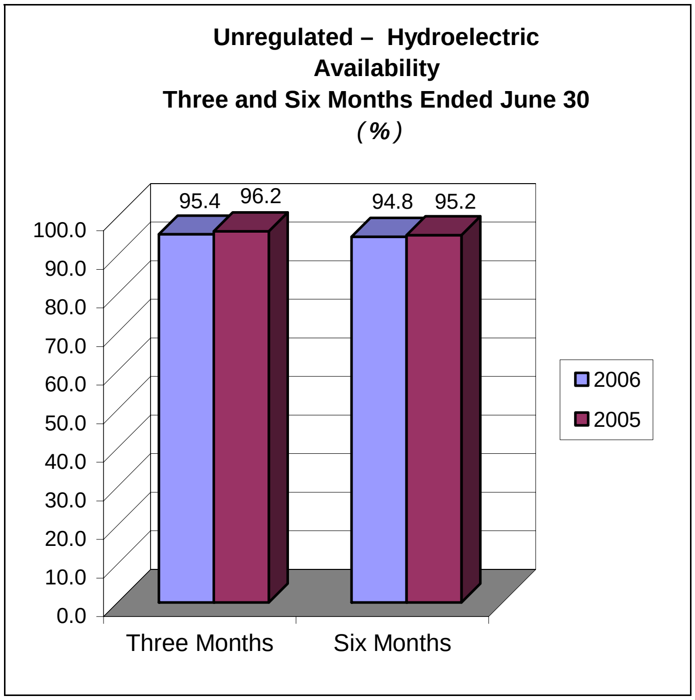
Volume

Electricity sales volume for the three months ended June 30, 2006 was 4.6 TWh compared to 4.4 TWh during the same period in 2005. For the six months ended June 30, 2006, electricity sales volume was 8.8 TWh compared to 8.2 TWh in 2005. The increase in volume in 2006 was primarily due to higher water levels in most Unregulated – Hydroelectric watersheds during 2006, compared to the same periods last year.



The equivalent forced outage rate for the Unregulated – Hydroelectric stations was 1.2 per cent for the three months ended June 30, 2006 compared to 1.5 per cent during the second quarter of 2005. The decrease in EFOR reflects sustained strong performance of the generating stations within the Unregulated – Hydroelectric segment.

The equivalent forced outage rate for the Unregulated – Hydroelectric stations was 1.2 per cent for the six months ended June 30, 2006 compared to 1.3 per cent during the same period in 2005.



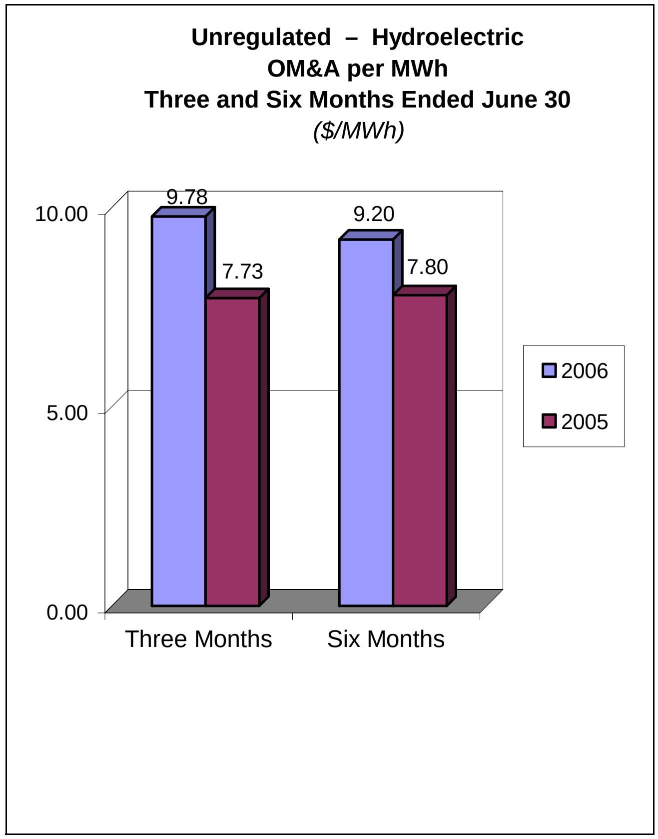
The availability for the Unregulated – Hydroelectric stations was 95.4 per cent for the three months ended June 30, 2006 compared to 96.2 per cent in the second quarter of 2005. The availability for the Unregulated – Hydroelectric stations was 94.8 per cent for the six months ended June 30, 2006 compared to 95.2 per cent for the same period in 2005. The lower availability was due to an increase in scheduled maintenance at several stations, partially offset by improved EFOR performance.

Fuel Expense

Fuel expense was $25 million for the three months ended June 30, 2006 compared to $23 million for the same period in 2005. Fuel expense was $45 million for the six months ended June 30, 2006 compared to $42 million for the same period last year. The increase in fuel expense was due to higher electricity generation. Generating stations within this segment are subject to the gross revenue charge.

Operations, Maintenance and Administration

OM&A expenses for the three months ended June 30, 2006 were $45 million compared to $34 million for the same period in 2005. OM&A expenses for the six months ended June 30, 2006 were $81 million compared to $64 million in 2005. The increase in OM&A expense in 2006 was mainly due to higher pension and OPEB costs, additional expenditures related to the development of the Lac Seul project, and additional maintenance costs including those related to runner upgrades at three Unregulated – Hydroelectric stations.



OM&A expense per MWh for the unregulated hydroelectric stations increased to $9.78/MWh in the second quarter of 2006 compared to $7.73/MWh for the same period in 2005. During the six months ended June 30, 2006, OM&A expense per MWh for the unregulated hydroelectric stations increased to $9.20/MWh compared to $7.80/MWh during the same period in 2005. The increases for the three and six month periods ended June 30, 2006, compared to the same periods last year, reflect higher OM&A expenses, partially offset by higher generation.

Depreciation and Amortization

Depreciation expense for the three months ended June 30, 2006 was $16 million compared to $18 million in the same period in 2005. Depreciation expense for the six months ended June 30, 2006 was $32 million compared to $33 million in 2005.

Unregulated – Fossil-Fuelled Segment

(millions of dollars)	Three Months Ended June 30 2006	2005	Six Months Ended June 30 2006	2005
Revenue, net of revenue limit and Market Power Mitigation Agreement rebates	**284**	375	**665**	756
Fuel expense	**130**	172	**305**	381
Gross margin	**154**	203	**360**	375
Operations, maintenance and administration	**143**	110	**260**	219
Depreciation and amortization	**47**	54	**96**	111
Accretion on fixed asset removal	**3**	3	**5**	5
Property and capital taxes	**4**	4	**8**	9
(Loss) income before impairment of long-lived assets	**(43)**	32	**(9)**	31
Impairment of long-lived assets	**-**	-	**-**	(202)
(Loss) income before interest and income taxes	**(43)**	32	**(9)**	(171)

Revenue

(millions of dollars)	Three Months Ended June 30 2006	2005	Six Months Ended June 30 2006	2005
Spot market sales, net of hedging instruments	**279**	443	**657**	932
Revenue limit rebate	**(23)**	(90)	**(63)**	(90)
Market Power Mitigation Agreement rebate	**-**	-	**-**	(129)
Other	**28**	22	**71**	43
Total revenue	**284**	375	**665**	756

Unregulated – Fossil-Fuelled revenue was $284 million for the three months ended June 30, 2006 compared to $375 million for the same period in 2005. The decrease in revenue of $91 million was primarily due to lower electricity generation of 1.4 TWh and lower average sales prices.

Unregulated – Fossil-Fuelled revenue was $665 million for the six months ended June 30, 2006 compared to $756 million for the same period in 2005. The decrease in revenue of $91 million in 2006 was primarily due to lower electricity generation of 2.8 TWh, partially offset by the receipt of revenue from the Lennox reliability must-run ("RMR") contract. The RMR contract is a cost-based contract with the IESO that provides for regular payments, which are subject to adjustments for actual costs.

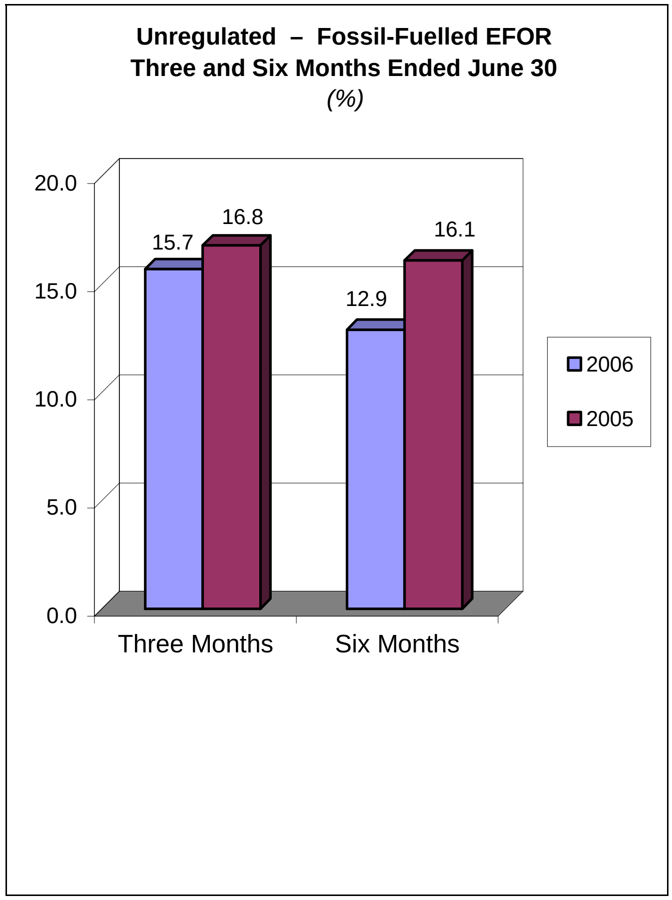
Electricity Prices

OPG's average sales price for its unregulated fossil-fuelled generation for the three months ended June 30, 2006 was 4.7¢/kWh compared to 5.5¢/kWh for the same period in 2005, after taking into account the revenue limit rebate. The decrease in OPG's average sales price was due primarily to lower average Ontario spot market prices.

OPG's average sales price for its unregulated fossil-fuelled generation for the six months ended June 30, 2006 was 4.8¢/kWh compared to 4.9¢/kWh in 2005. The decrease was primarily due to lower average Ontario spot market prices in 2006, largely offset by the favourable impact of the replacement of the Market Power Mitigation Agreement rebate with the revenue limit rebate effective April 1, 2005.

Volume

Electricity sales volume for the three months ended June 30, 2006 was 5.3 TWh compared to 6.7 TWh for the same period in 2005. Electricity sales volume for the six months ended June 30, 2006 was 12.3 TWh compared to 15.1 TWh in 2005. The decrease in volume in 2006 was primarily due to lower demand as a result of warmer winter weather in 2006 compared to 2005, and due to record high temperatures in June 2005 which did not reoccur in 2006. In addition, higher electricity generation from the nuclear generating stations also contributed to the decrease in electricity sales volumes for the Unregulated Fossil-Fuelled segment in 2006.



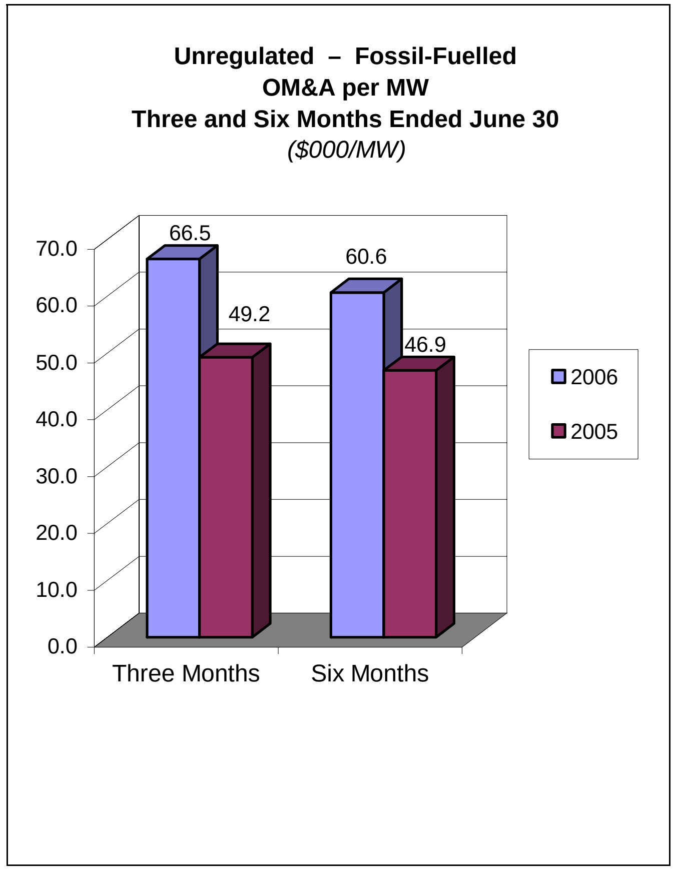
The equivalent forced outage rate for the fossil-fuelled generating stations was 15.7 per cent during the second quarter of 2006 compared to 16.8 per cent for the same period last year. During the six months ended June 30, 2006, the equivalent forced outage rate for the fossil-fuelled generating stations was 12.9 per cent compared to 16.1 per cent for the same period last year. The improved equivalent forced outage rate for the fossil-fuelled generating stations in 2006 was primarily due to improved equipment reliability at the Nanticoke generating station and the impact of closing the Lakeview generating station in April 2005.

Fuel Expense

Fuel expense was $130 million for the three months ended June 30, 2006 compared to $172 million for the same period in 2005. For the six months ended June 30, 2006, fuel expense was $305 million compared to $381 million for the six months ended June 30, 2005. The decrease in fuel expense in 2006 was primarily due to reduced electricity generation.

Operations, Maintenance and Administration

OM&A expenses for the three months ended June 30, 2006 were $143 million compared to $110 million for the same period in 2005. For the six months ended June 30, 2006, OM&A expenses were $260 million compared to $219 million in the 2005 period. OM&A expenses increased in 2006 mainly due to higher pension and OPEB costs, the write-off of unrecoverable costs related to the Thunder Bay generating station gas conversion project, and higher expenditures on maintenance.



OM&A expense per MW ($/MW) for the unregulated fossil-fuelled stations increased to $66,500/MW for the three months ended June 30, 2006 compared to $49,200/MW for the second quarter of 2005. During the six months ended June 30, 2006, OM&A expenses per MW for the unregulated fossil-fuelled stations increased to $60,600/MW compared to $46,900/MW in the same period in 2005. The increase during 2006 reflected higher OM&A expenses primarily due to higher pension and OPEB costs, the unrecoverable costs related to the Thunder Bay generating station gas conversion project, and the impact of lower generation capacity due to the closure of the Lakeview generating station in April 2005.

Depreciation and Amortization

Depreciation expense for the three months ended June 30, 2006 was $47 million, compared to $54 million for the same period in 2005. For the six months ended June 30, 2006, depreciation expense was $96 million compared to $111 million during the same period last year. The decrease in depreciation expense was mainly due to the extension of the service life of the Nanticoke generating station, for purposes of calculating depreciation, and the reduction in the asset base related to the impairment charge on the Lennox generating station, which was recorded in 2005. In the third quarter of 2005, OPG extended, for purposes of calculating depreciation, the remaining service life of the Nanticoke generating station by one year, from 2007 to 2008, based on further details provided by the Province with respect to its coal replacement program.

The estimated service life for all of the coal-fired generating stations as at June 30, 2006 , for purposes of calculating depreciation, was December 31, 2007, with the exception of the Nanticoke generating station, which was extended to December 31, 2008.

As a result of the delays in the Province’s plan to replace coal-fired generation, effective July 1, 2006, OPG extended the service life for all of the coal-fired generating stations, for purposes of calculating depreciation, to December 31, 2012. The extension will reduce depreciation expense by $66 million over the remainder of 2006, $133 million in 2007, and $49 million in 2008. From 2009 to 2012, the depreciation expense will increase by $62 million in each year. OPG will reassess the service life of the coal-fired stations upon release of the Ontario IPSP, and the subsequent approval by the OEB.

Other

(millions of dollars)	Three Months Ended June 30 2006	2005	Six Months Ended June 30 2006	2005
Revenue	**37**	28	**76**	47
Operations, maintenance and administration	**(6)**	8	**(5)**	17
Depreciation and amortization	**16**	14	**26**	28
Property and capital taxes	**3**	(6)	**5**	(8)
Income (loss) before interest and income taxes	**24**	12	**50**	10

Other revenue was $37 million for the three months ended June 30, 2006 compared to $28 million for the same period in 2005. For the six months ended June 30, 2006, other revenue was $76 million compared to $47 million for the six months ended June 30, 2005. The increase for both the three and six months ended June 30, 2006 was primarily due to an increase in mark-to-market gains on interconnected sales contracts and higher margins on interconnected sales.

OM&A expenses of the generation business segments include a service fee for the use of certain property, plant and equipment of the Other category. The total service fee allocation is recorded as a reduction to the Other category's OM&A expenses. For the three months ended June 30, 2006, the service fee allocation was $10 million for Regulated – Nuclear, $1 million for Regulated – Hydroelectric, $2 million for Unregulated – Hydroelectric and $3 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $16 million for the Other category. For the six months ended June 30, 2006, the service fee was $14 million for Regulated – Nuclear, $1 million for Regulated – Hydroelectric, $2 million for Unregulated – Hydroelectric and $5 million for Unregulated – Fossil-Fuelled, with a reduction in expenses of $22 million for the Other category. Results of the comparative periods have been reclassified to reflect the service fee.

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. If disclosed on a gross basis, revenue and power purchases for the three months ended June 30, 2006 would have increased by $40 million (three months June 30, 2005 – $45 million), and $89 million for the six months ended June 30, 2006 (six months ended June 30, 2005 – $100 million), with no impact on net income.

The carrying amounts and notional quantities of derivative instruments not designated for hedging purposes are disclosed in Note 11 in the unaudited interim consolidated financial statements as at and for the three and six months ended June 30, 2006.

Income Tax

OPG follows the liability method of tax accounting for its unregulated operations. Under the liability method, future tax assets and liabilities are determined based on differences between the accounting and tax bases 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. Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes relating to the rate regulated segments of its business using the taxes payable method. Under the taxes payable method, OPG does not recognize future income taxes relating to the rate regulated segments of its business to the extent those future income taxes are expected to be recovered in the regulated rates charged to future customers.

Income tax expense for the three months ended June 30, 2006 was $3 million compared to $4 million in the same period last year. The decrease in the income tax expense was primarily due to the elimination of the Large Corporations Tax and a reduction in the future income tax rates as a result of measures enacted from the Federal Budget of 2006. During the three months ended June 30, 2006 and 2005, the income tax expense was lower than what would otherwise have been recorded had OPG accounted for income tax for the regulated segment using the liability method by $8 million and $53 million, respectively.

For the six months ended June 30, 2006, income tax expense was $98 million compared to an income tax recovery of $8 million for the six months ended June 30, 2005. The increase in the income tax expense was primarily due to higher taxable income in 2006. The increase was partially offset by the elimination of the Large Corporations Tax and the reduction in the future income tax rates enacted from the Federal Budget of 2006. For the six months ended June 30, 2006 and 2005, the tax expense was lower than what would otherwise have been recorded had OPG accounted for income tax for the regulated segment using the liability method by $18 million and $53 million, respectively.

Income tax expense for the three and six months ended June 30, 2006 reflected the impact of accounting for income taxes for the regulated segments of the business using the taxes payable method for the entire periods. Income tax expense for the six months ended June 30, 2005 reflected the impact of the tax payable method for only three months, as this method was adopted upon inception of the rate regulation on April 1, 2005.

During the second quarter of 2005, as a result of the adoption of the taxes payable method for the rate regulated segments on April 1, 2005, OPG eliminated the net future income tax asset balance of $74 million related to the rate regulated segments and recognized the amount as a one-time extraordinary loss in determining net income.

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*, (Ontario) and tax related regulations are relatively new and 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 some of them possibly disallowed, resulting in a potential significant increase in OPG's tax provision upon reassessment. OPG is expecting to receive notification from the Provincial Tax Auditors with respect to their initial findings from their audit of OPG's 1999 taxation year. 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.

EARNINGS OUTLOOK

Earnings from the regulated business will continue to reflect the introduction of regulated prices related to most of OPG's baseload hydroelectric and all of its nuclear facilities. Earnings from the unregulated business will reflect the revenue limits applied to a significant portion of the output from OPG's unregulated assets, which are higher than the limit previously prescribed by the Market Power Mitigation Agreement.

In addition, OPG's future earnings will be impacted by decisions around the ultimate closure of the coal-fired generating stations, the impact of regulated prices by the OEB, and other aspects of the OPA supply mix process and plan.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, and credit facilities provided by OPG's Shareholder. These resources are required for continued investment in plant and technologies, and to meet other significant funding obligations including contributions to the pension fund, the Used Fuel Fund and Decommissioning Segregated Fund ("Decommissioning Fund") (the "Nuclear Funds"), and to service and repay long-term debt and revenue limit rebate obligations.

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Cash and cash equivalents, beginning of the period	**919**	135	**908**	2
Cash flow (used in) provided by operating activities	**(435)**	73	**(1)**	373
Cash flow (used in) investing activities	**(122)**	(196)	**(244)**	(431)
Cash flow (used in) provided by financing activities	**(2)**	399	**(303)**	467
Net (decrease) increase	**(559)**	276	**(548)**	409
Cash and cash equivalents, end of the period	**360**	411	**360**	411

Operating Activities

Cash flow used in operating activities for the three months ended June 30, 2006 was $435 million compared to cash flow provided by operating activities of $73 million during the same period in 2005. The decrease in cash flow from operating activities was mainly due to a higher payment to the IESO with respect to the revenue limit rebate during the second quarter of 2006, compared to the amount of the payment of the Market Power Mitigation Agreement rebate during the same quarter in 2005, increased contributions to the pension fund, and a decrease in revenue before the revenue limit rebate due to lower Ontario spot electricity market prices during the second quarter of 2006.

Cash flow used in operating activities for the six months ended June 30, 2006 was $1 million compared to cash flow provided by operating activities of $373 million during six months ended June 30, 2005. The decrease in cash flow provided by operating activities was mainly due to the higher revenue limit rebate payment during the second quarter of 2006, compared to the amount of the Market Power Mitigation Agreement rebate payments during the first six months of 2005, increased expenditures on fixed asset removal and nuclear waste management, increased contributions to the pension fund, and a decrease in revenue before rebates, partially offset by higher net income after adjustments for non-cash items.

During the six months ended June 30, 2006, OPG made a revenue limit rebate payment of $739 million, compared to a payment of $606 million for Market Power Mitigation Agreement rebate payments during the six months ended June 30, 2005. The $606 million Market Power Mitigation Agreement rebate payments made during the six months ended June 30, 2005 included a $386 million payment made during the three months ended June 30, 2005.

OPG made contributions of $65 million to the pension plan during the three months ended June 30, 2006 compared to $39 million during the same period in 2005. For the six months ended June 30, 2006, OPG made contributions of $130 million compared to $78 million during the same period last year. Pension contributions increased in 2006 to reflect higher funding requirements as a result of an updated actuarial valuation of the pension plan.

As required under the Ontario Nuclear Funds Agreement ("ONFA") between the Province and OPG, OPG made contributions of $113 million to the nuclear fixed asset removal and nuclear waste management funds during the second quarters of 2006 and 2005. For the six months ended June 30, 2006 and 2005, OPG made contributions of $227 million.

Investing Activities

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, invest in new generating stations and to maintain and improve service, reliability, safety and environmental performance.

Capital expenditures during the three months ended June 30, 2006 were $120 million compared with $106 million during the same period in 2005. The increase in capital expenditures was primarily due to OPG's increased investment in the Niagara Tunnel project, Portlands Energy Centre and the Pickering B nuclear generating station's ancillary power system. The increase was offset by lower investment during the three months ended June 30, 2006 at the Pickering A Unit 1 nuclear generating station compared to the same period in 2005, with the return to service of the unit in the fourth quarter of 2005.

For the six months ended June 30, 2006, capital expenditures were $234 million compared with $239 million for the six months ended June 30, 2005. The decrease in capital expenditures was primarily due to the lower investment at the Pickering A Unit 1 nuclear generating station, partially offset by the higher investment in the Niagara Tunnel, Portlands Energy Centre, the Pickering B nuclear generating station ancillary power system, and other projects within the Unregulated – Hydroelectric segment during the six months ended June 30, 2006, compared to the same period in 2005.

OPG's anticipated capital expenditures for 2006 are approximately $750 million, which include $180 million for the Niagara Tunnel project, $90 million for the Portlands Energy Centre, and $30 million for the Lac Seul project.

Included in the investing activity is OPG's investment in deferred regulatory assets of $2 million in the second quarter of 2006 compared to $90 million during the same period in 2005. For the six months ended June 30, 2006, OPG's investment in deferred regulatory assets was $12 million compared to $191 million in the same period in 2005. The lower investment in deferred regulatory assets during 2006 was primarily due to the return to service of Unit 1 at the Pickering A nuclear generating station in November 2005.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility which is divided into two tranches – a $500 million 364-day term tranche maturing May 22, 2007 and a $500 million three-year term tranche maturing May 22, 2009. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. OPG has not been required to borrow under its commercial paper program since April 2005. As at June 30, 2006, OPG had no other outstanding borrowing under its bank credit facility.

OPG also maintains $26 million (December 31, 2005 – $26 million) in short-term uncommitted overdraft facilities as well as $240 million (December 31, 2005 – $215 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 plans, and is required to post Letters of Credit as collateral with Local Distribution Companies ("LDCs") as prescribed by the OEB's Retail Settlement Code. At June 30, 2006, there were a total of $141 million (December 31, 2005 – $157 million) of Letters of Credit issued for the supplementary pension plans and collateral requirements to the LDCs.

To finance the Niagara Tunnel project, OPG negotiated an agreement with the OEFC to finance this project for up to $1 billion over the duration of the project. The funding will be advanced in the form of 10-year notes, on commercial terms and conditions. Advances under this facility are expected to commence in the fourth quarter of 2006.

As at June 30, 2006, OPG has a long-term credit rating of BBB+ by Standards & Poor's ('S&P') and 'A(low)' by Dominion Bond Rating Service ("DBRS"). In May of 2006, S&P issued a press release expressing their recognition of OPG's improving performance and prospects and announcing that they had upgraded the Company's short-term Canadian scale Commercial Paper debt rating to 'A-1(low)' from 'A-2'. The outlook on OPG's long-term credit rating is positive. In August of 2006, DBRS issued a rating report confirming OPG's long-term debt rating and short-term Commercial Paper rating of 'A(low)' and 'R-1(low)', respectively, with a stable outlook. Maintaining an investment grade credit rating is essential for corporate liquidity and future capital market access.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

Selected balance sheet data	**As at**	
	June 30	**December 31**
(millions of dollars)	**2006**	**2005**
Assets		
Accounts receivable	**285**	538
Property, plant and equipment – net	**11,290**	11,412
Nuclear fixed asset removal and nuclear waste management funds	**7,196**	6,788
Regulatory assets	**260**	266
Liabilities		
Accounts payable and accrued charges	**782**	958
Revenue limit rebate payable	**89**	739
Fixed asset removal and nuclear waste management	**8,957**	8,759
Other post employment benefits and supplementary pension plans (long-term portion)	**1,308**	1,212

Accounts Receivable

As at June 30, 2006, accounts receivable were $285 million compared to $538 million as at December 31, 2005. The decrease of $253 million was primarily due to lower sales volumes.

Property, Plant and Equipment – Net

Net property, plant and equipment as at June 30, 2006 was $11,290 million compared to $11,412 million as at December 31, 2005. The decrease of $122 million was primarily due to depreciation expense, partially offset by OPG's investment in fixed assets.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

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

In order to fund these liabilities, OPG established and manages, jointly with the Province, a Used Fuel Fund and a Decommissioning Fund, which are funded by OPG in accordance with the ONFA. The Used Fuel Fund is intended to fund future expenditures associated with the disposal of highly radioactive used nuclear fuel bundles. The Decommissioning Fund was established to fund future expenditures associated with nuclear fixed asset removal and the disposal of low and intermediate level nuclear waste materials. 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 at their amortized cost. 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 investments in the Nuclear Funds, which OPG has not recognized in its consolidated financial statements. The Nuclear Funds are referred to as the nuclear fixed asset removal and nuclear waste management funds in OPG's consolidated financial statements.

As at June 30, 2006, the Nuclear Funds on an amortized cost basis were $7,196 million compared to $6,788 million as at December 31, 2005. The increase of $408 million was due to contributions of $227 million, income earned of $192 million on the asset base, partially offset by payments of eligible program expenditures of $11 million.

Under the 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, 2006, the Used Fuel Fund included an amount due to the Province of $13 million (December 31, 2005 – $4 million). If the investments in the Used Fuel Fund were accounted for at fair market value in the unaudited interim consolidated financial statements at June 30, 2006, there would be an amount due to the Province of $272 million (December 31, 2005 – $306 million). In addition, under the ONFA, the Province is entitled to any surplus in the Used Fuel Fund, subject to a threshold funded ratio of 110 per cent compared to the value of the associated liabilities.

Under the 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, 2006, based on the estimate of costs to complete under the current approved ONFA Reference Plan (currently the 1999 Reference Plan), the Decommissioning Fund was fully funded on a market value basis and on an amortized cost basis. When the Decommissioning Fund is overfunded on an amortized cost basis, OPG will limit the earnings it recognizes in its consolidated financial statements, through a charge to the Decommissioning Fund with a corresponding payable to the Province, such that the amortized cost balance of the Decommissioning 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 Decommissioning Fund balance declines below the then currently approved cost estimate.

At June 30, 2006, the Decommissioning Fund asset value on an amortized cost basis was $4,236 million compared to a market value of $4,635 million, the difference representing net unrealized gains of $399 million. Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the then current 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 to be treated as a contribution to the Used Fuel Fund, and the OEFC is entitled to the remaining 50 per cent of such surplus. Any overfunding of the liability is payable to the Province on termination of the Decommissioning Fund. Therefore, the accounting for this overfunded position requires an adjustment to the amortized cost value of the assets in the Decommissioning Fund. This adjustment reduced the value of the assets by $25 million, to equal the value of the liabilities as defined by the current approved ONFA Reference Plan. If the investments in the Decommissioning Fund were accounted for at fair market value in the unaudited interim consolidated financial statements at June 30, 2006, and the Decommissioning Fund was terminated under the ONFA, there would be an amount due to the Province of $424 million (December 31, 2005 – $484 million).

OPG has commenced the process to review and update the estimate of costs to complete under the ONFA Reference Plan, and is targeting for an updated approved Reference Plan (the 2006 Reference Plan) to be in place in 2006. The scope and cost estimate of work required to place Units 2 and 3 at the Pickering A nuclear generating station in a safe storage state will be incorporated into the determination of the updated Reference Plan. The updated Reference Plan could have a significant impact on OPG's financial position due to potential obligations to the Province or OEFC related to surplus funds in the Decommissioning Fund. OPG is pursuing options to manage this potential impact.

Regulatory Assets

As at June 30, 2006, regulatory assets were $260 million compared to $266 million as at December 31, 2005. Effective January 1, 2005, in accordance with regulations pursuant to the *Electricity Restructuring Act*, *2004*, (Ontario), OPG established 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. The change in regulatory assets during the six months ended June 30, 2006 was mainly due to the amortization of $15 million of the deferred Pickering A return to service costs, partially offset by $12 million of non-capital costs that were deferred. OPG also recorded a regulatory asset of $2 million as at June 30, 2006 reflecting water conditions that were unfavourable compared to those forecasted for 2006.

Accounts Payable and Accrued Charges

Accounts payable and accrued charges as at June 30, 2006 were $782 million compared to $958 million as at December 31, 2005. The decrease of $176 million was primarily due to a reduced property tax balance, reduced coal purchases, and a reduction in other payable and accrued charges.

Revenue Limit Rebate Payable

The revenue limit rebate payable as at June 30, 2006 was $89 million compared to $739 million as at December 31, 2005. The decrease of $650 million was primarily due to a $739 million payment made in the second quarter of 2006. The balance of $89 million as at June 30, 2006 represents the revenue limit rebate for the six months ended June 30, 2006, which will be paid in August and November 2006.

Fixed Asset Removal and Nuclear Waste Management

The liability for fixed asset removal and nuclear waste management as at June 30, 2006 was $8,957 million compared to $8,759 million as at December 31, 2005. The increase of $198 million was primarily due to accretion due to the passage of time, partially offset by expenditures on nuclear waste management activities.

OPEB and Supplementary Pension Plans

The long-term portion of the liability for OPEB and supplementary pension plans was $1,308 million as at June 30, 2006 compared to $1,212 million as at December 31, 2005. The increase of $96 million was due to costs recognized in the first six months of 2006, net of benefit payments.

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under Canadian GAAP, are either not recorded in the Company's consolidated financial statements or are recorded on the Company's consolidated financial statements in amounts that differ from the full contract amounts. Principal off-balance sheet activities that OPG undertakes include securitization of certain accounts receivable agreements, guarantees which provide financial or performance assurance to third parties on behalf of certain subsidiaries, and certain derivative instruments and long-term fixed price contracts.

Securitization

In October 2003, OPG completed a revolving securitization agreement with an independent trust. The independent trust is not controlled by OPG, nor is OPG the primary beneficiary. 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, 2006, the average all-in cost of funds was 4.3 per cent and the pre-tax charges on sales to the trust were $3 million. For the six months ended June 30, 2006, the all-in cost of funds was 4.3 per cent and the pre-tax charges on sales to the trust were $6 million. The current securitization agreement extends to August 2009. Refer to Notes 3 and 4 of OPG's 2005 annual audited consolidated financial statements for additional information.

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.

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 United States dollar ("USD") 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 gain on electricity derivative instruments and interest rate hedges was $5 million as at June 30, 2006, compared to a deferred loss of $127 million as at December 31, 2005. For additional information, refer to Note 11 to OPG's unaudited interim consolidated financial statements as at and for the three and six months ended June 30, 2006.

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

RISK MANAGEMENT

A detailed discussion of OPG's inherent risks, including financial, operational, and strategic risks is included in the 2005 annual MD&A under the heading, *Risk Management*. The sections which follow provide highlights of these certain inherent risks.

Financial Risks

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 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, which includes fixed price and indexed contracts for fossil and nuclear fuels, and may include commodity derivatives.

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

	2006	2007	2008
Estimated generation output hedged [1]	93%	92%	91%
Estimated fuel requirements hedged [2]	100%	95%	82%
Estimated nitric oxide (NO) emission requirement hedged [3]	100%	100%	91%
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 regulated pricing commitments, agreements with the IESO, OPA auction sales and the revenue limit on OPG's 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 Regulations 397/01.

Value at Risk (VaR) for Trading Positions

Open trading positions are subject to measurement against Value at Risk (VaR) limits. VaR utilization ranged between $1.9 million and $3.0 million during the three months ended June 30, 2006, compared to $1.4 million and $2.0 million during the three months ended June 30, 2005. VaR utilization ranged between $1.5 million and $3.0 million during the six months ended June 30, 2006, compared to $1.2 million and $2.0 million during the six months ended June 30, 2005. VaR utilization is within the risk tolerance of the Company, under approved VaR limits.

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 monitors and reports its credit exposure with counterparties. OPG's management believes that the credit risk from energy sales and trading activities as at June 30, 2006 is 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, 2006:

			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-	36	3	-	-
A+ to A-	50	108	4	92
BBB+ to BBB-	85	49	3	27
BB+ to BB-	24	45	2	35
Below BB-	35	13	1	13
Subtotal	230	218	10	167
IESO [4]	1	431	1	431
Total	231	649	11	598

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.

4 Credit exposure to the IESO peaked at $1,029 million during the six months ended June 30, 2006 ($894 million during the six months ended June 30, 2005).

Liquidity Risk

OPG operates in a capital intensive business. Significant financial resources are required to fund capital improvement projects and maintenance at generating stations and potential expenditures necessary to comply with environmental or other regulatory requirements. In addition, the Company has other significant disbursement requirements including rebate payments associated with the revenue limit, annual funding obligations under ONFA, pension funding, and continuing debt maturities with the OEFC. A discussion of corporate liquidity is included in the Liquidity and Capital Resources section.

Foreign Exchange and Interest Rate Risk

OPG's foreign exchange exposure is attributable to two primary factors: USD denominated transactions such as the purchase of fossil fuels; and the influence of USD denominated commodity prices on Ontario electricity spot market prices, which impacts OPG's revenues. The magnitude and direction of the exposure to the USD from OPG's operations is impacted by generation reliability and price volatility of USD denominated commodities. OPG currently manages its exposure using forwards and other derivative products to periodically hedge portions of its anticipated USD exposures according to approved risk management policies.

OPG has interest rate exposure on its short-term borrowings and investment programs. The majority of OPG's debt is fixed on a long-term basis. Interest rate risk arises with the need to undertake new financing and with the potential addition of variable rate debt. Interest rate risk may be hedged using derivative instruments. The management of these risks is undertaken by selectively hedging in accordance with corporate risk management policies.

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. The uncertainty around the electricity generated by OPG's nuclear generating plants arises from various degradation processes affecting three key types of components: steam generators, fuel channels and feeders. Generation risks also arise from other structures, components or systems in the nuclear generating stations such as cooling water systems, turbines and reactor structures and components. Some of the most significant risks within the nuclear generating stations are discussed below.

Thinning of the carbon steel feeders used to transport the hot pressurized water in the reactor to the steam generators is an industry-wide issue. Thinning of feeders 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 life, reduce the thinning rate, and improve the capability to replace feeders, where required. Wall thickness measurements of removed feeders and field inspections at the Pickering A generating station Units 1 and 4 in 2005 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 the Pickering A generating station, and to determine the extent of future feeder replacements. Feeder replacements will take place at the Darlington and Pickering A generating stations during the fall 2006 outages. The feeders at the Pickering B generating station have been found to be less affected by thinning than those at the Darlington and Pickering A generating stations.

Cracking of feeders 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 cracking at any of its nuclear facilities, but is carrying out inspections during regularly planned outages. Recent observations of additional shallow cracks at a CANDU plant outside Ontario have increased the risk that OPG's inspection program may need to be further increased in 2007 and beyond. OPG is 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.

In 2004, inspections of the Pickering A generating station 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. 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 may impact outage duration and outage costs. Inspection of Pickering A Unit 4 in 2005 confirmed the presence of another single crack. Prior inspection of Pickering A Unit 1 in 2004 did not uncover cracks. Inspection of Pickering B Units 5 and 6 in 2005 and Unit 8 in 2006 have not uncovered any further cracks. This observation, together with improved construction methods used on the Pickering B steam generators (as compared to Pickering A steam generators) suggest that this degradation mechanism is likely not active on Pickering B. Inspection for cracks of Pickering A Unit 4 and Pickering B Unit 7 steam generator tubes is planned for the Fall of 2006.

In 2005 and 2006, a few new deep tube pits were detected in the steam generators of Unit 5 and 8, at the Pickering B generating station. Although no tube leaks occurred and there were no forced outages as a result of tube leaks during this time period, deep pits may be indicative of the recurrence of active tube corrosion due to deposit build-up. The impact of this degradation is an increased risk of future forced outages due to tube leaks. This is mainly an economic risk in that it would force a unit shutdown to repair the leak. An economic assessment is being conducted in 2006 to determine the benefit and cost of performing a more aggressive deposit cleaning strategy to reduce the probability of a tube leak.

Pressure tubes are life limited by hydrogen concentration which impacts flaw and blister assessments. Recent measurements taken at Unit 8 of the Pickering B generating station indicate that the rate of hydrogen pickup, may be faster than anticipated. In addition, movement of some garter springs post repositioning has been noted. The consequence of these findings is increased inspection and maintenance which may extend outage durations. Confirmatory measurements are being planned for the upcoming Unit 8 outage in 2008. These findings are not expected to affect the Darlington or Pickering A generating stations.

Environmental Risk

OPG incurs substantial capital and operating costs to comply with environmental laws. The regulatory requirements relate to discharges to the environment; construction of or modifications to our facilities; the handling, use, storage, transportation, disposal and clean-up of hazardous substances, and waste; and the decommissioning of generating facilities at the end of their useful lives.

OPG's Environmental Policy commits OPG to meet all applicable legislative requirements and voluntary environmental commitments and integrate environmental factors into business planning and decision-making. This policy also commits OPG to maintain comprehensive environmental management systems ("EMSs") at our generating facilities consistent with the ISO 14001 standard.

The Province originally proposed that mercury emissions from OPG's coal-fired generating stations would be eliminated by 2010, consistent with the original plans to replace coal-fired generation by 2009. However, with the recently announced delays to the plan to replace coal-fired generation, OPG has entered into discussions with the Ministries of Energy, Environment and Finance and the OPA regarding mercury emission reduction scenarios beyond 2009, the associated costs and implementation schedules. The operational and financial risks to OPG will be dependent on any new mercury emissions limits that are developed for the period beyond 2009.

OPG's environmental risks, emissions monitoring and environmental risk management programs are described in detail in the Environmental Risk section of the MD&A for the year ended December 31, 2005. OPG continues to monitor the developments with respect to changes to the federal Climate Change Plan presently being pursued by the federal government in order to assess any impact on OPG.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Changes in Accounting Policies and Estimates

Certain of the accounting policies disclosed in OPG's 2005 annual audited consolidated financial statements are recognized as critical by virtue of the subjective and complex judgements 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 relate to rate regulated accounting, income taxes, business segments, impairment of generating stations and other fixed assets, pension and other post employment benefits, asset retirement obligations, and depreciation. For further details, refer to the 2005 annual MD&A under the heading, *Critical Accounting Policies and Estimates*.

The accounting policies used in preparing the unaudited interim consolidated financial statements are consistent with those used in the preparation of the 2005 annual consolidated financial statements, except as disclosed in Note 2 to the unaudited interim consolidated financial statements.

The accounting estimates related to asset depreciation require significant management judgment to assess the appropriate useful lives of OPG's long-lived assets, including consideration of various technological and other factors. The Province has accepted the advice of the IESO in their June 2006 report that indicates a need for 2,500 to 3,000 MW of additional capacity to maintain system reliability. Therefore, further delays will be necessary in the Province's plan to replace coal-fired generation by 2009. As a result of these delays, effective July 1, 2006, OPG extended the life for all of the coal-fired generating stations, for purposes of calculating depreciation, to December 31, 2012. The extension will reduce depreciation expense by $66 million over the remainder of 2006, $133 million in 2007, and $49 million in 2008. From 2009 to 2012, the depreciation expense will increase by $62 million in each year. OPG will reassess the service life of the coal-fired stations upon release of the IPSP, and subsequent approval by the OEB. Any change to the estimated service life of the coal-fired generating stations, for purposes of calculating depreciation, could have a material impact on OPG's consolidated financial statements.

Future Changes in Accounting Policies and Estimates

In 2005, the Canadian Institute of Chartered Accountants issued three new accounting standards: Financial Instruments – Recognition and Measurement, Hedges, and Comprehensive Income. These standards provide guidance on the recognition and measurement of financial assets, financial liabilities and non-financial derivatives. They also provide guidance on the classification of financial instruments and hedge accounting.

OPG is in the process of assessing the impact of these new standards on OPG's financial position and results of operations. These accounting standards will be effective for OPG on January 1, 2007.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters. This financial information has been prepared in accordance with Canadian GAAP.

(millions of dollars)	**June 30 2006**	**March 31 2006**	**December 31 2005**	**September 30 2005**
Revenue after revenue limit and Market Power Mitigation Agreement rebates	**1,345**	1,508	1,496	1,571
Net income	**143**	199	160	181
Net income per share	**$0.56**	$0.78	$0.62	$0.71

(millions of dollars)	**June 30 2005**	**March 31 2005**	**December 31 2004**	**September 30 2004**
Revenue after revenue limit and Market Power Mitigation Agreement rebates	1,373	1,358	1,215	1,212
Income (loss) before extraordinary item	137	(38)	34	(15)
Income (loss) before extraordinary item per share	$0.53	$(0.15)	$0.13	$(0.06)
Net income (loss)	63	(38)	34	(15)
Net income (loss) per share	$0.25	$(0.15)	$0.13	$(0.06)

OPG's quarterly results are impacted by changes in demand primarily 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. Since April 1, 2005, revenue has increased due to the introduction of regulated prices for OPG's baseload hydroelectric and nuclear facilities and other related regulatory changes. The revenue limit and the Market Power Mitigation Agreement rebates, regulated prices, and OPG's hedging strategies significantly reduced the impact of seasonal price fluctuations on the results of operations.

Additional items which impacted net income in certain quarters above include the following:

- Tax benefit of $93 million recorded during the fourth quarter of 2004 related to the elimination of a valuation allowance due to the introduction of rate regulation;
- Lower OM&A expenses due to the deferral of non-capital costs related to the Pickering A nuclear generating station Unit 1 return to service project, beginning January 1, 2005, as required by regulation pursuant to the *Electricity Restructuring Act, 2004*, (Ontario);
- Impairment loss on the Lennox generating station of $202 million recorded during the first quarter of 2005, reflecting the amount of the carrying value of the station;
- Lower income tax expense due to the use of the taxes payable method for the regulated segments commencing April 1, 2005;
- Higher average OPG sales prices subsequent to the introduction of rate regulation effective April 1, 2005;
- Impairment loss of $63 million related to Units 2 and 3 of the Pickering A generating station, recorded in the second quarter of 2005;
- One-time extraordinary loss of $74 million recorded in the second quarter of 2005, resulting from the adoption of rate regulated accounting and the corresponding use of the taxes payable method;
- Write-off of $22 million and $35 million of excess inventory as a result of not returning Pickering A generating station Units 2 and 3 to service recorded in the third and fourth quarters of 2005 respectively;
- Higher depreciation expense related to the return to service of Unit 1 at the Pickering A generating station in the fourth quarter of 2005;
- Decrease in depreciation expense primarily due to extension of service lives, for accounting purposes, the Nanticoke station, Pickering B station and Unit 4 of the Pickering A station beginning in the first quarter of 2006; and,
- Higher pension and OPEB costs during the first and second quarters of 2006 mainly due to changes in economic assumptions used to measure the costs.

SUPPLEMENTAL EARNINGS MEASURES

In addition to providing net income in accordance with Canadian GAAP, OPG's MD&A, unaudited interim consolidated financial statements as at and for the three and six months ended June 30, 2006 and 2005 and the notes thereto, present certain non-GAAP financial measures. These financial measures do not have standard definitions prescribed by 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, consolidated 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 revenue limit and Market Power Mitigation Agreement rebates and fuel expense.

(2) **Earnings** is defined as net income.

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CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars except where noted)	**Three Months Ended June 30**		**Six Months Ended June 30**	
	2006	**2005**	**2006**	**2005**
Revenue				
Revenue before revenue limit and Market Power Mitigation Agreement rebates	**1,374**	1,514	**2,942**	3,284
Revenue limit rebate *(Note 14)*	**(29)**	(141)	**(89)**	(141)
Market Power Mitigation Agreement rebate	**-**	-	**-**	(412)
	1,345	1,373	**2,853**	2,731
Fuel expense	**243**	289	**521**	599
Gross margin	**1,102**	1,084	**2,332**	2,132
Expenses				
Operations, maintenance and administration	**683**	616	**1,333**	1,203
Depreciation and amortization *(Note 4)*	**180**	192	**356**	385
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)*	**125**	120	**250**	239
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(103)**	(112)	**(192)**	(183)
Property and capital taxes	**22**	17	**47**	38
	907	833	**1,794**	1,682
Income before impairment of long-lived assets	**195**	251	**538**	450
Impairment of long-lived assets *(Note 4)*	**-**	63	**-**	265
Income before interest, income taxes and extraordinary item	**195**	188	**538**	185
Net interest expense	**49**	47	**98**	94
Income before income taxes and extraordinary item	**146**	141	**440**	91
Income tax expenses (recoveries)				
Current	**26**	7	**46**	14
Future *(Note 9)*	**(23)**	(3)	**52**	(22)
	3	4	**98**	(8)
Income before extraordinary item	**143**	137	**342**	99
Extraordinary item *(Note 9)*	**-**	74	**-**	74
Net income	**143**	63	**342**	25
Basic and diluted income per common share before extraordinary item *(dollars)*	**0.56**	0.53	**1.33**	0.39
Basic and diluted income per common share *(dollars)*	**0.56**	0.25	**1.33**	0.10
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 (DEFICIT) (UNAUDITED)

Six Months Ended June 30 *(millions of dollars)*	**2006**	**2005**
Retained earnings (deficit), beginning of period	**261**	(105)
Net income	**342**	25
Retained earnings (deficit), end of period	**603**	(80)

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(millions of dollars)	**Three Months Ended June 30 2006**	**Three Months Ended June 30 2005**	**Six Months Ended June 30 2006**	**Six Months Ended June 30 2005**
Operating activities				
Net income	**143**	63	**342**	25
Adjust for non-cash items:				
Depreciation and amortization *(Note 4)*	**180**	192	**356**	385
Accretion on fixed asset removal and nuclear waste management liabilities	**125**	120	**250**	239
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(103)**	(112)	**(192)**	(183)
Pension cost	**55**	28	**109**	56
Other post employment benefits and supplementary pension plans	**63**	46	**127**	91
Future income taxes	**(23)**	(3)	**52**	(22)
Transition rate option contracts	**(4)**	(9)	**(13)**	(18)
Mark-to-market on energy contracts	**(8)**	2	**(17)**	4
Provision for used nuclear fuel	**8**	6	**16**	13
Impairment of long-lived assets	**-**	63	**-**	265
Regulatory assets and liabilities	**12**	-	**19**	-
Extraordinary item	**-**	74	**-**	74
Other	**2**	1	**2**	-
	450	471	**1,051**	929
Contributions to nuclear fixed asset removal and nuclear waste management funds	**(113)**	(113)	**(227)**	(227)
Expenditures on fixed asset removal and nuclear waste management	**(42)**	(25)	**(70)**	(39)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management	**4**	4	**11**	10
Contributions to pension fund	**(65)**	(39)	**(130)**	(78)
Expenditures on other post employment benefits and supplementary pension plans	**(16)**	(17)	**(31)**	(33)
Revenue limit rebate	**(739)**	-	**(739)**	-
Market Power Mitigation Agreement rebate	**-**	(386)	**-**	(606)
Expenditures on restructuring *(Note 13)*	**(1)**	(4)	**(6)**	(9)
Net changes to other long-term assets and liabilities	**(26)**	(20)	**(57)**	(29)
Changes in non-cash working capital balances *(Note 16)*	**113**	202	**197**	455
Cash flow (used in) provided by operating activities	**(435)**	73	**(1)**	373
Investing activities				
Investment in regulatory assets *(Note 5)*	**(2)**	(90)	**(12)**	(191)
Investment in fixed assets *(Note 4)*	**(120)**	(106)	**(234)**	(239)
Net proceeds from sale (purchase) of long-term investments	**-**	-	**2**	(1)
Cash flow (used in) investing activities	**(122)**	(196)	**(244)**	(431)
Financing activities				
Issuance of long-term debt *(Note 7)*	**-**	400	**-**	495
Repayment of long-term debt *(Note 7)*	**(2)**	(1)	**(303)**	(2)
Net decrease in short-term notes *(Note 6)*	**-**	-	**-**	(26)
Cash flow (used in) provided by financing activities	**(2)**	399	**(303)**	467
Net (decrease) increase in cash and cash equivalents	**(559)**	276	**(548)**	409
Cash and cash equivalents, beginning of period	**919**	135	**908**	2
Cash and cash equivalents, end of period	**360**	411	**360**	411

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**June 30 2006**	**December 31 2005**
Assets		
Current assets		
Cash and cash equivalents	**360**	908
Accounts receivable *(Note 3)*	**285**	538
Future income taxes *(Note 9)*	**12**	18
Fuel inventory	**629**	581
Materials and supplies	**110**	115
	1,396	2,160
Fixed assets *(Note 4)*		
Property, plant and equipment	**15,377**	15,172
Less: accumulated depreciation	**4,087**	3,760
	11,290	11,412
Other long-term assets		
Deferred pension asset	**684**	663
Nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**7,196**	6,788
Long-term materials and supplies	**312**	273
Regulatory assets *(Note 5)*	**260**	266
Long-term accounts receivable and other assets	**58**	61
	8,510	8,051
	21,196	21,623

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**June 30 2006**	**December 31 2005**
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(Note 13)*	**782**	958
Revenue limit rebate payable *(Note 14)*	**89**	739
Long-term debt due within one year *(Note 7)*	**706**	806
Deferred revenue due within one year	**12**	12
Income and capital taxes payable	**117**	81
	1,706	2,596
Long-term debt *(Note 7)*	**2,886**	3,089
Other long-term liabilities		
Fixed asset removal and nuclear waste management *(Note 8)*	**8,957**	8,759
Other post employment benefits and supplementary pension plans	**1,308**	1,212
Long-term accounts payable and accrued charges	**172**	183
Deferred revenue	**138**	144
Future income taxes *(Note 9)*	**287**	241
Regulatory liabilities *(Note 5)*	**13**	12
	10,875	10,551
Shareholder's equity		
Common shares	**5,126**	5,126
Retained earnings	**603**	261
	5,729	5,387
	21,196	21,623

Commitments and Contingencies (Notes 1, 4, 6, 7, 11, and 12)

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, 2006 AND 2005 (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 these interim consolidated financial statements. These interim financial statements do not contain all the disclosures required by Canadian generally accepted accounting principles for annual financial statements. Accordingly, these interim consolidated financial statements should be read in conjunction with the most recently prepared annual consolidated financial statements for the year ended December 31, 2005.

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 2005 comparative amounts have been reclassified from financial statements previously presented to conform to the 2006 financial statement presentation.

The consolidated financial statements include the accounts of Ontario Power Generation Inc. ("OPG" or the "Company") and its subsidiaries. OPG accounts for its interests in jointly controlled entities using the proportionate consolidation method. All significant intercompany transactions have been eliminated on consolidation.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulated Accounting

In December 2004, the *Electricity Restructuring Act, 2004* received royal assent. A regulation made pursuant to that statute provides that OPG receives regulated prices beginning April 1, 2005, for most of OPG's baseload hydroelectric facilities and all of its nuclear facilities. This includes electricity generated by Sir Adam Beck 1, 2 and Pump generating stations, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, the Pickering A and B, and Darlington nuclear generating stations.

OPG's regulated prices were determined by the Province of Ontario (the "Province") based on total projected production and costs of operation, plus the cost of capital including an average five per cent return on equity. The 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, the Province may amend these initial prices.

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, *the Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Minister of Energy. It regulates the Province's natural gas and electricity industries and carries out its regulatory functions through public hearings and other more informal processes such as consultations.

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. When the regulation provides assurance that incurred costs will be recovered in the future, then OPG 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 OPG reports a regulatory liability. Also, if the regulation provides for lesser or greater than planned revenue to be received or returned by OPG through future rates, then OPG recognizes and reports a regulatory asset or liability, respectively. The measurement of such regulatory assets and liabilities are subject to certain estimates and assumptions, including assumptions made in the interpretation of the regulation. See Note 5 and Note 9 to the interim consolidated financial statements for additional disclosures required under rate regulated accounting.

Long-Term Portfolio Investments

Long-term portfolio investments, other than investments owned by the Company's wholly owned subsidiary OPG Ventures Inc. ("OPGV"), are stated at amortized cost and include the nuclear fixed asset removal and nuclear waste management funds. Gains and losses on long-term investments are recognized when investments are sold. When a decline in the value of investments occurs, which is considered to be other than temporary, a provision for loss is established.

Investments owned by OPGV are recorded at fair value, and changes to the fair value of the investments are included in revenue in the period in which the change occurs. The fair values of these investments are estimated based on readily available market information or using estimation techniques based on historical performance.

Income Taxes

OPG follows the liability method of accounting for income taxes of its unregulated operations. Under the liability method, future tax assets and liabilities are determined based on differences between the accounting and tax bases 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. 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. Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes relating to the rate regulated segments of its business using the taxes payable method. Under the taxes payable method, OPG does not recognize future income taxes relating to the rate regulated segments of its business to the extent those future income taxes are expected to be recovered in the regulated rates charged to future customers.

Changes in Accounting Policies and Estimates

Depreciation of Long-Lived Assets

The accounting estimates related to the depreciation of long-lived assets require significant management judgment to assess the appropriate useful lives of OPG's long-lived assets, including consideration of various technological and other factors.

Effective January 1, 2006, following the completion of a review of the life limiting components of the Pickering B nuclear generating station, OPG revised and extended, for the purpose of calculating depreciation, the estimated remaining service life of the Pickering B nuclear generating station to 2014 from 2009.

The Province has accepted the advice of the Independent Electricity System Operator ("IESO") in their June 2006 report that indicates a need for 2,500 to 3,000 MW of additional capacity to maintain system reliability. Therefore, further delays will be necessary in the Province's plan to replace coal-fired generation by 2009. As a result of these delays, effective July 1, 2006, OPG extended the life for all of the coal-fired generating stations, for purposes of calculating depreciation, to December 31, 2012. The extension will reduce depreciation expense by $66 million over the remainder of 2006, $133 million in 2007, and $49 million in 2008. From 2009 to 2012, the depreciation expense will increase depreciation by $62 million in each year. OPG will reassess the service life of the coal-fired stations upon release of the Integrated Power System Plan, and subsequent approval by the OEB. Any change to the estimated service life the coal-fired generating stations, for purposes of calculating depreciation, could have a material impact on OPG's consolidated financial statements.

Reportable Segments

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 on the majority of this output. With the introduction of rate regulation, OPG revised its reportable business segments to separately reflect the regulated and unregulated aspects of its business. Since the second quarter of 2005, OPG reported its business segments as Regulated – Nuclear, Regulated – Hydroelectric, and Unregulated Generation. Commencing in the first quarter of 2006, OPG separated the Unregulated Generation business segment into two reportable segments, identified as Unregulated – Fossil-Fuelled and Unregulated – Hydroelectric, as a result of changes in the management structure of these segments. Results for the comparative periods have been reclassified to reflect the revised disclosure.

Future Accounting Changes

In 2005, the Canadian Institute of Chartered Accountants ("CICA") issued three new accounting standards: Handbook Section 1530, Comprehensive Income; Handbook Section 3855, Financial Instruments – Recognition and Measurement; and Handbook Section 3865, Hedges. These standards apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006.

These standards will be effective for OPG beginning in 2007. OPG is in the process of assessing the impact of these standards on its consolidated financial statements. The impact of implementing these new standards on OPG's consolidated financial statements is not yet determinable as it will be dependent on outstanding positions and their fair values at the time of transition. The following provides further information on each of the three new accounting standards as they relate to OPG.

Comprehensive Income

As a result of adopting these standards, a new category, accumulated other comprehensive income, will be added to shareholders' equity in the consolidated balance sheets. Major components for this category will include unrealized gains and losses on financial assets classified as available-for-sale, changes in the fair value of the effective portion of cash flow hedging instruments, and unrealized foreign currency translation amounts, net of hedging, arising from self-sustaining foreign operations. These amounts will be recorded in the statement of other comprehensive income until the criteria for recognition in the consolidated statement of income are met.

Financial Instruments – Recognition and Measurement

Under the new standard, for accounting purposes, financial assets will be classified as one of the following: held-to-maturity, loans and receivables, held-for-trading or available-for-sale, and financial liabilities will be classified as held-for-trading or other than held-for-trading. Financial assets and liabilities held-for-trading will be measured at fair value with gains and losses recognized in net income. Financial assets held-to-maturity, loans and receivables and financial liabilities other than those held-for-trading, will be measured at amortized cost. Available-for-sale instruments will be measured at fair value with unrealized gains and losses recognized in other comprehensive income. The standard also permits designation of any financial instrument as held-for-trading upon initial recognition. All derivatives, including embedded derivatives that must be separately accounted for, generally must be classified as held-for-trading and recorded at fair value in the consolidated balance sheets.

Hedges

This new standard specifies the criteria under which hedge accounting can be applied and how hedge accounting is to be executed for each of the permitted hedging strategies: fair value hedges, cash flow hedges and hedges of a foreign currency exposure of a net investment in a self-sustaining foreign operation. In a fair value hedging relationship, the carrying value of the hedged item is adjusted by gains or losses attributable to the hedged risk and recognized in net income. This change in fair value of the hedged item, to the extent that the hedging relationship is effective, is offset by changes in the fair value of the derivative. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative will be recognized in other comprehensive income. The ineffective portion will be recognized in net income. The amounts recognized in accumulated other comprehensive income will be reclassified to net income in the periods in which net income is affected by the variability in the cash flows of the hedged item. In hedging a foreign currency exposure of a net investment in a self-sustaining foreign operation, foreign exchange gains and losses on the hedging instruments will be recognized in other comprehensive income.

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. In December 2005, the Company extended this agreement to August 2009.

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, 2006, the Company has recognized pre-tax charges of $3 million (three months ended June 30, 2005 – $2 million) on such sales at an average cost of funds of 4.3 per cent (three months ended June 30, 2005 – 2.9 per cent). For the six months ended June 30, 2006, the Company has recognized pre-tax charges of $6 million (six months ended June 30, 2005 – $4 million) on such sales at an average cost of funds of 4.3 per cent (six months ended June 30, 2005 – 2.9 per cent). As at June 30, 2006, OPG had sold receivables of $300 million (December 31, 2005 – $300 million) from its total portfolio of $444 million (December 31, 2005 – $668 million).

4. FIXED ASSETS

Depreciation and amortization expense for the three and six months ended June 30, 2006 and 2005 consists of the following:

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Depreciation and amortization	**179**	190	**354**	382
Nuclear waste management costs	**1**	2	**2**	3
	180	192	**356**	385

Interest capitalized to construction in progress at 6.0 per cent during the three and six months ended June 30, 2006 (three and six months ended June 30, 2005 – 6.0 per cent) was $4 million and $8 million respectively (three and six months ended June 30, 2005 – $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, 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 completed, in the second quarter of 2005, 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. The assessment considered results 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, OPG determined that the return to service of these two units was not justified on a commercial basis even though technically feasible. OPG recorded an impairment loss of $63 million in the second quarter of 2005 related to the carrying amount of these two units including construction in progress.

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 generating station, 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 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, the Province advised OPG that it would not support an arrangement that would allow for the recovery of the carrying value of the Lennox generating station. As a result, OPG recorded an impairment loss of $202 million in the first quarter of 2005.

In March 2006, the OEB issued a decision approving a reliability must-run ("RMR") contract between OPG and the Independent Electricity System Operator ("IESO") for the Lennox generating station, for the period October 1, 2005 to September 30, 2006. Reliability must-run contracts are designed to ensure that generating stations remain available to maintain the reliability of the electricity system. In its decision, the OEB found it appropriate for OPG to recover the fixed and variable operating costs of the Lennox generating station that are not recovered through market revenues. As a result of the decision, OPG recorded $15 million in revenue in the second quarter of 2006 (six months ended June 30, 2006 - $44 million). The RMR contract is a cost-based contract that provides for regular payments, which are subject to adjustments for actual costs. OPG negotiated a similar contract with the IESO for the period October 1, 2006 to September 30, 2007. The contract requires approval of the OEB prior to becoming effective.

5. REGULATORY ASSETS AND LIABILITIES

The changes in the regulatory assets and liabilities for the six months ended June 30, 2006 are as follows:

(millions of dollars)	**Pickering A Return to Service Costs**	**Ancillary Service Revenue Variance**	**Hydro-electric Production Variance**	**Other**
Regulatory assets (liabilities), beginning of the period	261	5	(4)	(8)
Increase (decrease) during the period	12	(10)	6	-
Amortization during the period	(15)	-	-	-
Regulatory assets (liabilities), end of the period	**258**	**(5)**	**2**	**(8)**

The regulatory assets and liabilities as at June 30, 2006 and December 31, 2005 are as follows:

(millions of dollars)	**June 30 2006**	**December 31 2005**
Regulatory assets		
Pickering A generating station return to service costs	**258**	261
Ancillary service revenue variance	**-**	5
Hydroelectric production variance	**2**	-
Total regulatory assets	**260**	266
Regulatory liabilities		
Ancillary service revenue variance	**5**	-
Hydroelectric production variance	**-**	4
Other	**8**	8
Total regulatory liabilities	**13**	12

Pickering A Return to Service Costs

Effective January 1, 2005, in accordance with a regulation made under the *Electricity Restructuring Act, 2004*, OPG was 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. As a result, the change in accounting was prospectively adopted on January 1, 2005, with no retroactive adoption. As at June 30, 2006, the deferral account was $258 million, consisting of non-capital costs of $232 million relating to Unit 1, $19 million relating to Units 2 and 3, $19 million of general return to service costs, and interest of $7 million. The accumulated amortization as of June 30, 2006 was $19 million.

As at December 31, 2005, the deferral account was $261 million, consisting of non-capital costs of $228 million relating to Unit 1, $19 million relating to Units 2 and 3, $11 million of general return to service costs, and interest of $7 million. The accumulated amortization as of December 31, 2005 was $4 million.

Under the regulation, the OEB is directed to ensure that OPG recovers any balance in the deferral account on a straight-line basis over a period not to exceed 15 years.

Variance Accounts

Effective April 1, 2005, in accordance with a regulation made under the *Electricity Restructuring Act, 2004*, OPG was directed to establish variance accounts for costs incurred on or after April 1, 2005 that are associated with differences in hydroelectric 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 reduction in revenue during the six months ended June 30, 2006 of $10 million, reflecting ancillary services revenue that was favourable compared to that forecasted for 2006. OPG recorded revenue during the six months ended June 30, 2006 of $6 million reflecting water conditions that were unfavourable compared to those forecasted for 2006. The OEB is directed by the regulation to ensure recovery to the extent that the OEB is satisfied that the costs recorded in the account were prudently incurred and accurately recorded. Any balances approved by the OEB will be amortized over a period not to exceed three years. The amortization will commence after OPG receives a rate order from the OEB.

The other regulatory liability consists of a portion of non-regulated revenue earned by OPG's regulated assets, which will result in a reduction of future regulated rates to be established by the OEB.

Had OPG not accounted for the variances as a regulatory asset and liability, revenue for the six months ended June 30, 2006 would have been higher by $4 million.

6. SHORT-TERM CREDIT FACILITIES

OPG's $1 billion revolving committed bank credit facility is divided into two tranches – a $500 million 364-day term tranche maturing May 22, 2007, and a $500 million three-year term tranche maturing May 22, 2009. The total credit facility will be used primarily as support for notes issued under OPG's commercial paper program. As of June 30, 2006 and December 31, 2005, OPG had no commercial paper or other outstanding borrowing under this facility.

OPG also maintains $26 million (December 31, 2005 – $26 million) in short-term uncommitted overdraft facilities as well as $240 million (December 31, 2005 – $215 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 plans and is required to post Letters of Credit as collateral with Local Distribution Companies ("LDCs") as prescribed by the OEB's Retail Settlement Code. At June 30, 2006, there was a total of $141 million (December 31, 2005 – $157 million) of Letters of Credit issued, which included $138 million relating to the supplementary pension plans (December 31, 2005 – $138 million) and $3 million (December 31, 2005 – $19 million) relating to collateral requirements to the LDCs.

7. LONG-TERM DEBT

Long-term debt consists of the following:

(millions of dollars)	**June 30 2006**	**December 31 2005**
Notes payable to the Ontario Electricity Financial Corporation	**3,395**	3,695
Share of non-recourse limited partnership debt	**197**	200
	3,592	3,895
Less: due within one year		
Notes payable to the Ontario Electricity Financial Corporation	**700**	800
Share of limited partnership debt	**6**	6
	706	806
Long-term debt	**2,886**	3,089

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.

Interest paid during the three months ended June 30, 2006 was $8 million (three months ended June 30, 2005 – $16 million), of which $4 million relates to interest paid on long-term debt (three months ended June 30, 2005 – $10 million). Interest paid during the six months ended June 30, 2006 was $126 million (six months ended June 30, 2005 – $119 million), of which $118 million relates to interest paid on long-term debt (six months ended June 30, 2005 – $110 million). Interest on the notes payable to OEFC is paid in the first and third quarter of the year.

8. Fixed Asset Removal and Nuclear Waste Management

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

(millions of dollars)	**June 30 2006**	**December 31 2005**
Liability for nuclear used fuel management	**5,069**	4,940
Liability for nuclear decommissioning and low and intermediate level waste management	**3,699**	3,627
Liability for non-nuclear fixed asset removal	**189**	192
Fixed asset removal and nuclear waste management liabilities	**8,957**	8,759

The change in the fixed asset removal and nuclear waste management liability for the six months ended June 30, 2006 and the year ended December 31, 2005 are as follows:

(millions of dollars)	**June 30 2006**	**December 31 2005**
Liabilities, beginning of period	**8,759**	8,339
Increase in liabilities due to accretion	**250**	476
Increase in liabilities due to nuclear used fuel and nuclear waste management variable expenses	**18**	34
Liabilities settled by expenditures on waste management	**(70)**	(90)
Liabilities, end of period	**8,957**	8,759

OPG recognizes asset retirement obligations for fixed asset removal and nuclear waste management, discounted for the time value of money. OPG has estimated both the amount and timing of future cash expenditures based on current plans for fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

Ontario Nuclear Funds Agreement

OPG sets aside and invests funds in segregated custodian accounts 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, 2006 and December 31, 2005, consist of the following:

	Amortized Cost Basis		Fair Value	
(millions of dollars)	**June 30 2006**	**December 31 2005**	**June 30 2006**	**December 31 2005**
Decommissioning Fund	**4,236**	4,106	**4,635**	4,583
Due to Province – Decommissioning Fund	**(25)**	(7)	**(424)**	(484)
	4,211	4,099	**4,211**	4,099
Used Fuel Fund [1]	**2,998**	2,693	**3,257**	2,995
Due (to) from Province – Used Fuel Fund	**(13)**	(4)	**(272)**	(306)
	2,985	2,689	**2,985**	2,689
	7,196	6,788	**7,196**	6,788

[1] The Ontario NFWA Trust represents $1,075 million as at June 30, 2006 (December 31, 2005 – $1,003 million) of the Used Fuel Fund on an amortized cost basis.

9. INCOME TAXES

The following table summarizes the difference in the balance sheet amounts under the method used by the Company to account for income taxes compared to what would have been reported had OPG applied the liability method for the regulated business as at June 30, 2006 and December 31, 2005:

	June 30, 2006		December 31, 2005	
(millions of dollars)	**As Stated**	**Liability Method**	**As Stated**	**Liability Method**
Future income tax assets – current	**12**	**32**	18	38
Long-term future income tax liabilities	**(287)**	**(408)**	(241)	(344)

The following table summarizes the difference in the income statement amounts under the method used by the Company to account for income taxes compared to what would have been reported had OPG applied the liability method for the regulated business for the three and six months ended June 30, 2006 and 2005:

	Three Months Ended		Six Months Ended	
(millions of dollars)	**June 30 2006**	**June 30 2005**	**June 30 2006**	**June 30 2005**
As Stated:				
Extraordinary item	**-**	74	**-**	74
Future income tax (recovery) expense	**(23)**	(3)	**52**	(22)
Liability Method:				
Future income tax expense	**(15)**	50	**70**	31

The amount of cash income taxes paid during the three months ended June 30, 2006 was $6 million (three months ended June 30, 2005 – $5 million). For the six months ended June 30, 2006, cash income taxes paid were $14 million (six months ended June 30, 2005 - $9 million).

During the three months ended June 30, 2005, OPG recorded a one-time extraordinary loss of $74 million as a result of the adoption of rate regulated accounting for income taxes related to the rate regulated business segments.

The Company has revised its future income tax assets and liabilities to reflect the lower federal income tax rates recently enacted.

OPG has taken certain filing positions for corporate income and capital taxes that may be challenged on audit and possibly disallowed and result in a significant increase in the tax obligation upon reassessment. There is still uncertainty around the amount of the tax provision, and Management is not able to determine the impact of that uncertainty on the consolidated financial statements.

10. BENEFIT PLANS

The post employment benefit programs include pension, group life insurance, health care and long-term disability benefits. Pension and other post employment benefit ("OPEB") obligations are impacted by factors including interest rates, adjustments arising from plan amendments, changes in assumptions and experience gains or losses. The 2006 costs are based on a measurement of the pension and OPEB obligations and the pension fund assets, as at December 31, 2005.

Total benefit costs for the three and six months ended June 30, 2006 and 2005 are as follows:

	Three Months Ended June 30		**Six Months Ended June 30**	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Registered pension plan	**55**	28	**109**	56
Supplementary pension plans	**3**	5	**7**	9
OPEB	**60**	41	**120**	82

11. FINANCIAL INSTRUMENTS

Contracts for all trading transactions are carried on the consolidated balance sheet as assets or liabilities at fair value, with changes in fair value recorded in trading revenue as gains or losses.

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.

Forward pricing information is inherently uncertain so that fair values of the derivative instruments may not accurately represent the cost to enter into these positions. To address the impact of some of this uncertainty on trading positions, OPG established liquidity reserves against the mark-to-market gains or losses of these positions. During the three months ended June 30, 2006, the liquidity reserve increased trading revenue by $4 million (three months ended June 30, 2005 – increased trading revenue by $2 million). During the six months ended June 30, 2006, the liquidity reserves reduced trading revenue by $5 million (six months ended June 30, 2005 – increased trading revenue by $7 million).

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, 2006			**December 31, 2005**	
Gain (loss)						
Electricity derivative instruments	**5.5 TWh**	**1-4 yrs**	**(11)**	4.1 TWh	1-2 yrs	(125)
Foreign exchange derivative instruments	**U.S. $5**	**July/06**	**-**	U.S. $15	Jan/06	-
Interest rate hedges	**400**	**1-15 yrs**	**14**	400	1-15 yrs	(7)

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, 2006 was U.S. $0.90 (December 31, 2005 – U.S. $0.87) for every Canadian dollar.

OPG entered into a number of forward start interest rate swap agreements to hedge against the effect of future interest rate movement based on the anticipated future borrowing requirement for the Niagara Tunnel project. These transactions are accounted for as hedges.

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, 2006		**December 31, 2005**	
Foreign exchange derivative	**-**	**-**	U.S. $3	-
Commodity derivative instruments				
Assets	**7.4 TWh**	**28**	3.3 TWh	13
Liabilities	**2.2 TWh**	**(26)**	1.1 TWh	(37)
		2		(24)
Liquidity reserve		**(8)**		(3)
Total		**(6)**		(27)

Foreign exchange derivative instruments that were not designated as hedges had a weighted average exchange rate of U.S. $0.85 as at December 31, 2005.

12. COMMITMENTS AND CONTINGENCIES

Litigation

Various legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of its business activities.

On August 9, 2006, a Notice of Action and Statement of Claim in the amount of $500 million was served on OPG and Bruce Power L.P. by British Energy Limited and British Energy International Holdings Limited ("British Energy"), claiming that OPG is liable to them for breach of contract and negligence. Particulars of the claim have not been provided at this time, however, the claim pertains to corrosion in the Bruce Unit 8 Steam Generators. OPG is in the process of evaluating the merits of this claim.

In July 2004, OPG and two individual OPG employees were each charged with criminal negligence causing death and criminal negligence causing bodily harm in relation to a 2002 drowning accident at Barrett Chute. The trial commenced on January 16, 2006, and is expected to last at least until the late fall of 2006. 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 and could have a significant effect on OPG's financial position. Management has provided for contingencies that are determined to be likely and are reasonably measurable.

Environmental

OPG was required to assume certain environmental obligations from Ontario Hydro. A provision of $76 million was established as at April 1, 1999 for such obligations. During the six months ended June 30, 2006, expenditures of $1 million (six months ended June 30, 2005 - $ 1 million) were recorded against the provision. As at June 30, 2006, the remaining provision was $55 million (December 31, 2005 - $56 million).

Current operations are subject to regulation with respect to air, soil and water quality and other environmental matters by federal, provincial and local authorities. The cost of obligations associated with current operations is provided for on an ongoing basis. Management believes it has made adequate provision in its consolidated financial statements to meet OPG's current environmental obligations.

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.

13. RESTRUCTURING

The change in the restructuring liability for termination benefits for the six months ended June 30, 2006 and the year ended December 31, 2005 are as follows:

(millions of dollars)	**June 30 2006**	**December 31 2005**
Liability, beginning of period	**12**	20
Restructuring charges	**-**	10
Payments	**(6)**	(18)
Liability, end of period	**6**	12

During 2005, OPG recorded restructuring charges of $10 million, which consisted of $4 million related to the Lakeview generating station in the Unregulated – Fossil-Fuelled segment and $6 million related to the Energy Markets business which was included in the Other category.

14. REVENUE LIMIT REBATE

Eighty-five per cent of the generation output from OPG's unregulated generation assets, excluding the Lennox generating station and forward sales as of January 1, 2005, is subject to a revenue limit. The incremental output from a generating station where there has been a refurbishment or expansion of these assets is also excluded from the output covered by the revenue limit. In addition, until the Transition – Generation Corporation Designated Rate Options ("TRO") expired on April 30, 2006, volumes sold under such options were also excluded from the revenue limit rebate. This revenue limit, which was originally established for a period of 13 months ending April 30, 2006, was subsequently extended for an additional three years. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh. On May 1, 2007, the revenue limit will return to 4.7¢/kWh and increase to 4.8¢/kWh effective May 1, 2008. In addition, volumes sold under a Pilot Auction administered by the OPA are subject to a revenue limit that is 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Revenues above these limits are returned to the IESO for the benefit of consumers.

The change in the revenue limit rebate liability for the six months ended June 30, 2006 and the year ended December 31, 2005 are as follows:

(millions of dollars)	**June 30 2006**	**December 31 2005**
Liability, beginning of the year	**739**	-
Increase to provision during the period	**89**	739
Payments made during the period	**(739)**	-
Liability, end of period	**89**	739

15. BUSINESS SEGMENTS

Effective April 1, 2005, the output from most of OPG's baseload hydroelectric facilities and all of its nuclear facilities became rate regulated. With the introduction of rate regulation, OPG revised its reportable business segments to separately reflect the regulated and unregulated aspects of its business. In the first quarter of 2006, OPG separated the Unregulated Generation business segment into two reportable segments identified as Unregulated – Fossil-Fuelled and Unregulated – Hydroelectric, as a result of changes in the management structure of these segments. Results for the comparative periods have been reclassified to reflect the revised disclosure.

Operations, maintenance and administration ("OM&A") expenses of the generation business segments include a service fee for the use of certain property, plant and equipment of the Other category. The total service fee allocation is recorded as a reduction to the Other category's OM&A expenses. For the three months ended June 30, 2006, the service fee allocation was $10 million for Regulated – Nuclear, $1 million for Regulated – Hydroelectric, $2 million for Unregulated – Hydroelectric and $3 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $16 million for the Other category. For the six months ended June 30, 2006, the service fee was $14 million for Regulated – Nuclear, $1 million for Regulated – Hydroelectric, $2 million for Unregulated – Hydroelectric and $5 million for Unregulated – Fossil-Fuelled, with a reduction in expenses of $22 million for the Other category. Results of the comparative periods have been reclassified to reflect the service fee.

Segment Income (Loss) for Three Months Ended June 30, 2006	Regulated		Unregulated			
	Nuclear	Hydro-electric	Hydro-electric	Fossil-Fuelled	Other	Total
(millions of dollars)						
Revenue before revenue limit rebate	**636**	**164**	**230**	**307**	**37**	**1,374**
Revenue limit rebate	**-**	**-**	**(6)**	**(23)**	**-**	**(29)**
	636	**164**	**224**	**284**	**37**	**1,345**
Fuel expense	**28**	**60**	**25**	**130**	**-**	**243**
Gross margin	**608**	**104**	**199**	**154**	**37**	**1,102**
Operations, maintenance and administration	**478**	**23**	**45**	**143**	**(6)**	**683**
Depreciation and amortization	**84**	**17**	**16**	**47**	**16**	**180**
Accretion on fixed asset removal and nuclear waste management liabilities	**122**	**-**	**-**	**3**	**-**	**125**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(103)**	**-**	**-**	**-**	**-**	**(103)**
Property and capital taxes	**9**	**3**	**3**	**4**	**3**	**22**
Income (loss) before interest, income taxes and extraordinary item	**18**	**61**	**135**	**(43)**	**24**	**195**

Segment (Loss) income for Three Months Ended June 30, 2005	Regulated		Unregulated			
	Nuclear	Hydro-electric	Hydro-electric	Fossil-Fuelled	Other	Total
(millions of dollars)						
Revenue before revenue limit rebate	540	202	279	465	28	1,514
Revenue limit rebate	-	-	(51)	(90)	-	(141)
	540	202	228	375	28	1,373
Fuel expense	25	69	23	172	-	289
Gross margin	515	133	205	203	28	1,084
Operations, maintenance and administration	446	18	34	110	8	616
Depreciation and amortization	90	16	18	54	14	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	10	5	4	4	(6)	17
(Loss) income before impairment of long-lived assets	(36)	94	149	32	12	251
Impairment of long-lived asset	63	-	-	-	-	63
(Loss) income before interest, income taxes and extraordinary item	(99)	94	149	32	12	188

Segment Income (Loss) for Six Months Ended June 30, 2006	Regulated Nuclear	Regulated Hydro-electric	Unregulated Hydro-electric	Unregulated Fossil-Fuelled	Other	Total
(millions of dollars)						
Revenue before revenue limit rebate	**1,345**	**339**	**454**	**728**	**76**	**2,942**
Revenue limit rebate	**-**	**-**	**(26)**	**(63)**	**-**	**(89)**
	1,345	**339**	**428**	**665**	**76**	**2,853**
Fuel expense	**59**	**112**	**45**	**305**	**-**	**521**
Gross margin	**1,286**	**227**	**383**	**360**	**76**	**2,332**
Operations, maintenance and administration	**953**	**44**	**81**	**260**	**(5)**	**1,333**
Depreciation and amortization	**169**	**33**	**32**	**96**	**26**	**356**
Accretion on fixed asset removal and nuclear waste management liabilities	**245**	**-**	**-**	**5**	**-**	**250**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(192)**	**-**	**-**	**-**	**-**	**(192)**
Property and capital taxes	**19**	**8**	**7**	**8**	**5**	**47**
Income (loss) before interest, income taxes and extraordinary item	**92**	**142**	**263**	**(9)**	**50**	**538**

Segment (Loss) Income for Six Months Ended June 30, 2005	Regulated Nuclear	Regulated Hydro-electric	Unregulated Hydro-electric	Unregulated Fossil-Fuelled	Other	Total
(millions of dollars)						
Revenue before revenue limit and Market Power Mitigation Agreement rebates	1,280	472	510	975	47	3,284
Revenue limit rebate	-	-	(51)	(90)	-	(141)
Market Power Mitigation Agreement rebate	(160)	(65)	(58)	(129)	-	(412)
	1,120	407	401	756	47	2,731
Fuel expense	54	122	42	381	-	599
Gross margin	1,066	285	359	375	47	2,132
Operations, maintenance and administration	867	36	64	219	17	1,203
Depreciation and amortization	179	34	33	111	28	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	21	9	7	9	(8)	38
(Loss) income before impairment of long-lived assets	(52)	206	255	31	10	450
Impairment of long-lived assets	63	-	-	202	-	265
(Loss) income before interest, income taxes and extraordinary item	(115)	206	255	(171)	10	185

	Regulated		Unregulated			
(millions of dollars)	**Nuclear**	**Hydro-electric**	**Hydro-electric**	**Fossil-Fuelled**	**Other**	**Total**
Selected Balance Sheet Information						
As at June 30, 2006						
Segment property, plant and equipment, net	**3,066**	**4,091**	**3,071**	**464**	**598**	**11,290**
As at December 31, 2005						
Segment property, plant and equipment, net	3,156	4,054	3,076	531	595	11,412
Selected Cash Flow Information						
Three months ended June 30, 2006						
Investment in fixed assets	**37**	**36**	**15**	**14**	**18**	**120**
Three months ended June 30, 2005						
Investment in fixed assets	65	20	8	11	2	106
Six months ended June 30, 2006						
Investment in fixed assets	**78**	**70**	**26**	**28**	**32**	**234**
Six months ended June 30, 2005						
Investment in fixed assets	160	37	15	21	6	239

16. CHANGES IN NON-CASH WORKING CAPITAL BALANCES

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Accounts receivable	**74**	38	**271**	(51)
Fuel inventory	**(59)**	(26)	**(48)**	73
Materials and supplies	**-**	(12)	**5**	(26)
Revenue limit rebate	**29**	141	**89**	141
Market Power Mitigation Agreement rebate	**-**	-	**-**	412
Accounts payable and accrued charges	**48**	58	**(156)**	(105)
Income and capital taxes payable	**21**	3	**36**	11
	113	202	**197**	455

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. Regulated prices for the baseload hydroelectric and nuclear facilities, the revenue limit related to the generation from OPG's other generating assets and OPG's hedging strategies significantly reduced the impact of seasonal price fluctuations on the results of operations.