

May 11, 2006

ONTARIO POWER GENERATION REPORTS 2006 FIRST QUARTER FINANCIAL RESULTS

[Toronto]: Ontario Power Generation Inc. (“OPG” or the “Company”) today reported its financial and operating results for the three months ended March 31, 2006. Net income for the first quarter of 2006 was \$199 million compared with a net loss of \$38 million for the same period in 2005.

“Our revenues and earnings during the quarter increased primarily as a result of our current regulatory structure. We continued to improve the reliability of our generating stations, which also favourably impacted earnings. Despite lower Ontario electricity demand caused by a warmer than normal winter, electricity production was only marginally lower than in the first quarter of 2005,” said President and CEO Jim Hankinson.

Earnings for the three months ended March 31, 2006 were favourably impacted by an increase in gross margin from electricity sales because of an increase in OPG’s average sales price compared to the same period in 2005. OPG’s average sales price increased as a result of the introduction of regulated prices and other related regulatory changes effective April 1, 2005. However, OPG continued to be a moderating influence on Ontario electricity prices, receiving an average sales price for the three months ended March 31, 2006 of 4.7¢/kWh, which was lower than the weighted average hourly Ontario spot electricity market price in the first quarter of 2006 of 5.2¢/kWh. OPG’s average sales price in the first quarter of 2005 was 4.3¢/kWh. The impact of the improved gross margin on earnings was partly offset by an increase in pension and other post employment benefit costs primarily caused by changes in economic assumptions.

OPG’s earnings during the three months ended March 31, 2005, were unfavourably impacted by an impairment charge of \$202 million related to its Lennox generating station. At the time, it was determined that due to its relatively high variable costs, the Lennox station would not be able to recover its carrying value from the wholesale electricity market in the future.

Electricity generated in the first quarter 2006 of 28.4 terawatt hours (TWh) was slightly lower than first quarter 2005 generation of 28.8 TWh. Electricity generated from OPG’s nuclear generating assets increased primarily as a result of the return to service of Unit 1 at the Pickering A generating station. Hydroelectric generation increased slightly due to higher water levels at stations in northern and eastern Ontario. Fossil generation declined as a result of lower Ontario electricity demand caused by a warmer than normal winter.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

<i>(millions of dollars)</i>	Three Months Ended March 31	
	2006	2005
<i>Earnings</i>		
Revenue before Market Power Mitigation Agreement and revenue limit rebates	1,568	1,770
Market Power Mitigation Agreement and revenue limit rebates	(60)	(412)
Fuel expense	(278)	(310)
Gross margin	1,230	1,048
Operations, maintenance and administration	650	587
Other expenses	286	309
Impairment of long-lived assets	-	202
Income tax expense (recovery)	95	(12)
Net income (loss)	199	(38)
<i>Cash flow</i>		
Cash flow provided by operating activities	434	300
<i>Electricity Generation (TWh)</i>		
Regulated – Nuclear	12.7	12.0
Regulated – Hydroelectric	4.5	4.6
Unregulated Generation – Hydroelectric	4.2	3.8
Unregulated Generation – Fossil-Fuelled	7.0	8.4
Total electricity generation	28.4	28.8
<i>Average electricity sales price¹ (¢/kWh)</i>		
Regulated – Nuclear ²	4.9	4.3
Regulated – Hydroelectric ²	3.6	4.3
Unregulated Generation – Hydroelectric ³	4.8	4.4
Unregulated Generation – Fossil-Fuelled ³	4.9	4.4
OPG average sales price	4.7	4.3
<i>Nuclear unit capability factor (per cent)</i>		
Darlington	94.6	93.9
Pickering A	91.2	99.8
Pickering B	78.6	84.3
<i>Equivalent forced outage rate (per cent)</i>		
Unregulated – Fossil-Fuelled	10.8	14.2
<i>Availability (per cent)</i>		
Regulated – Hydroelectric	92.7	91.8
Unregulated – Hydroelectric	94.4	94.8

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.

To address the urgent electricity needs of downtown Toronto, the Province of Ontario has directed the Ontario Power Authority to negotiate an agreement with Portlands Energy Centre ("PEC"), to develop a 550 megawatt ("MW") gas-fired station. PEC is a partnership between TransCanada Energy Ltd. and OPG. The plant will be commissioned in two phases, with 330 MW of capacity available by mid 2008 and another 220 MW available during 2009, to meet the requirements identified by the Independent Electricity System Operator ("IESO"). PEC is negotiating a design-build contract for the facility with SNC Lavalin, and has entered into an agreement with them with respect to preliminary engineering and procurement.

Approximately 85 per cent of the production from OPG's fossil-fuelled and non-baseload hydroelectric generating assets has been subject to a revenue limit based on an average price of 4.7¢/kWh. This revenue limit was originally established for a period of 13 months ending April 30, 2006. During the first quarter, this limit was 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. Electricity sales from OPG's fossil-fuelled and non-baseload hydroelectric stations of 45 TWh during 2005 represented 41 per cent of OPG's total electricity sales of 108.5 TWh. The financial impact of the rebate is dependent on both the volumes subject to the revenue limit, and prices in the Ontario electricity market.

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 interim consolidated financial statements and Management's Discussion and Analysis of financial condition and results of operations as at and for the three months ended March 31, 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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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 months ended March 31, 2006. For a complete understanding 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 May 10, 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, 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.

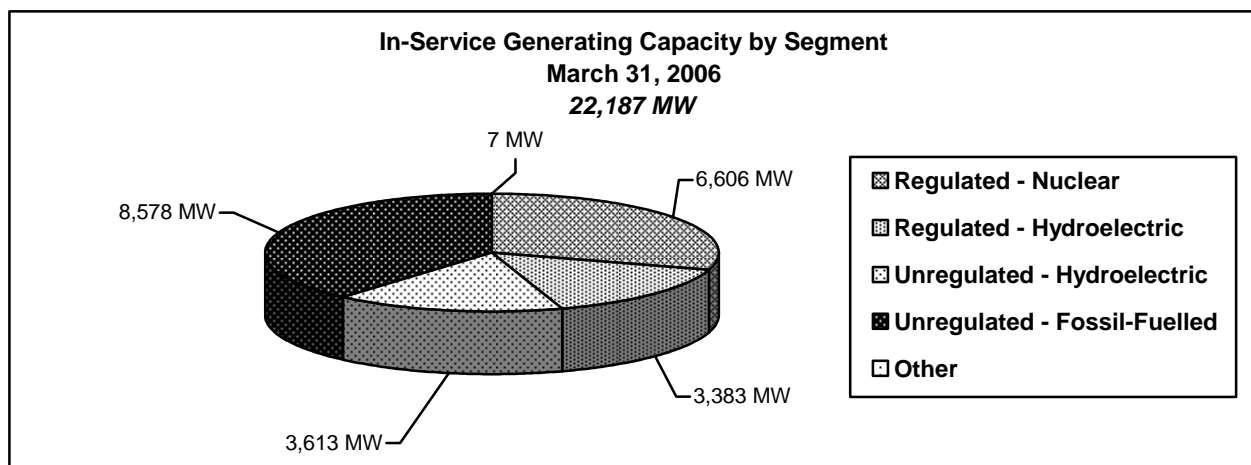
THE COMPANY

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 March 31, 2006, OPG had 22,187 megawatts ("MW") of in-service generating capacity. During the first quarter of 2006, OPG added 14 MW of in-service generating capacity through a runner upgrade program at certain stations within the unregulated hydroelectric segment. OPG's electricity generating portfolio consisted of three nuclear generating stations, five fossil-fuelled generating stations, 64 hydroelectric generating stations and three wind generating stations (which includes a 50 per cent interest in the Huron Wind joint venture). In addition, OPG, ATCO Power Canada Ltd. and ATCO Resources Ltd. co-own a gas-fired generating station. OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P. ("Bruce Power").

Effective April 1, 2005, the output from most of OPG's baseload hydroelectric facilities and all of its nuclear facilities became rate regulated. OPG continues to receive the spot market price for the output from its remaining hydroelectric, fossil-fuelled and wind generating stations, subject to a revenue limit 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 has 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 period have been reclassified to reflect the revised disclosure.



RATE REGULATION

A regulation was introduced pursuant to the *Electricity Restructuring Act, 2004*, 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 includes electricity generated from Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and Pickering A and B, and Darlington nuclear facilities.

The regulated price received by OPG for the first 1,900 megawatt hours (“MWh”) of production from the regulated hydroelectric facilities in any hour is \$33.00/MWh (3.3¢/kWh). As an incentive to encourage maximum hydroelectric 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, Transition – Generation Corporation Designated Rate Options (“TRO”) volumes and forward sales as of January 1, 2005, are subject to a revenue limit based on an average price of \$47.00/MWh (4.7¢/kWh). The revenue limit was originally established for a period of 13 months ending April 30, 2006, which 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 Ontario Power Authority (“OPA”) will receive a revenue limit that is 0.5¢/kWh higher than the revenue limit applicable to OPG’s other generating assets. Revenues above these limits will be 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.

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

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*.

<i>(millions of dollars)</i>	Three Months Ended March 31	
	2006	2005
<i>Revenue</i>		
Revenue before revenue limit and Market Power Mitigation Agreement rebates	1,568	1,770
Revenue limit rebate	(60)	-
Market Power Mitigation Agreement rebate	-	(412)
	1,508	1,358
<i>Earnings</i>		
Income before impairment of long-lived asset and income taxes	294	152
Impairment of long-lived asset	-	202
Income (loss) before income taxes	294	(50)
Income tax expenses (recoveries)	95	(12)
Net income (loss)	199	(38)
<i>Electricity production (TWh)</i>	28.4	28.8
<i>Cash flow</i>		
Cash flow provided by operating activities	434	300

OPG's earnings improved in the first quarter of 2006 compared to the first quarter of 2005 following the implementation of the regulatory changes which took effect April 1, 2005. Revenue from OPG's nuclear generating stations was favourably impacted by the introduction of regulated prices that reflect the projected production and costs of operations, including an average five per cent return on equity, and the corresponding elimination of the Market Power Mitigation Agreement rebate. Revenue from OPG's regulated hydroelectric generating stations was negatively impacted by these regulatory changes. While a significant portion of OPG's output from its unregulated assets was subject to the revenue limit, this limit was higher than the limit that was prescribed under the Market Power Mitigation Agreement.

Net income for the three months ended March 31, 2006 was \$199 million compared to a net loss of \$38 million in the three months ended March 31, 2005, an increase of \$237 million. Income before income taxes for the three months ended March 31, 2006 was \$294 million compared to a loss before income taxes of \$50 million for the three months ended March 31, 2005, an increase of \$344 million.

The following is a summary of the factors impacting OPG's results for the three months ended March 31, 2006 compared to results for the same period in 2005, on a before-tax basis:

(millions of dollars – before tax)

(Loss) before income taxes for the period ended March 31, 2005	(50)
Changes in gross margin	
Increase in electricity sales prices after Market Power Mitigation Agreement rebate and revenue limit rebate	132
Change in electricity generation by segment:	
Regulated – Nuclear	38
Regulated – Hydroelectric	(4)
Unregulated – Hydroelectric	21
Unregulated – Fossil-Fuelled	(43)
Other changes in gross margin	38
	<u>182</u>
Increase in pension and other post employment benefit costs	(45)
Amortization of Pickering A Return to Service deferral account balance	(10)
Increase in earnings on nuclear fixed asset removal and nuclear waste management funds	18
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	17
Other changes	(20)
Increase in income before income taxes, excluding impairment of long-lived asset	142
Impairment of Lennox generating station	202
	<u>294</u>
Income before income taxes for the period ended March 31, 2006	294

Earnings for the three months ended March 31, 2006 were significantly impacted by an increase in gross margin from electricity sales due to an increase in OPG's average sales price compared to the same period in 2005. The increase in OPG's average sales price was due to the introduction of regulated prices and other related regulatory changes effective April 1, 2005.

Operations, maintenance and administration ("OM&A") expenses for the three months ended March 31, 2006 were \$650 million compared to \$587 million during the same period in 2005. The increase was mainly due to an increase in pension and OPEB costs primarily due to changes in economic assumptions used to measure the costs. In addition, OM&A expenses during the three months ended March 31, 2006 included amortization of a portion of the Pickering A return to service costs, which were previously deferred in accordance with a regulation pursuant to the *Electricity Restructuring Act, 2004*.

During the three months ended March 31, 2005, OPG recorded an impairment charge of \$202 million related to its Lennox generating station. 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 during the three months ended March 31, 2006 were impacted by the effect of adopting rate regulated accounting for income taxes for the regulated segments of the business commencing April 1, 2005. OPG accounts for income taxes relating to the rate regulated segments of its business using the taxes payable method. As a result, OPG did not record a future tax expense of \$10 million for the rate regulated segments during the three months ended March 31, 2006, which would have been recorded had OPG accounted for income taxes for the regulated segments using the liability method.

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 three months ended March 31, 2006 and the Market Power Mitigation Agreement rebate for the three months ended March 31, 2005, are as follows:

<i>(¢/kWh)</i>	Three Months Ended March 31	
	2006	2005
Weighted average hourly Ontario spot electricity market price	5.2	5.7
Regulated – Nuclear	4.9	4.3
Regulated – Hydroelectric ¹	3.6	4.3
Unregulated – Hydroelectric ²	4.8	4.4
Unregulated – Fossil-Fuelled ²	4.9	4.4
OPG's average sales price	4.7	4.3

¹ During the period from January 1 to March 31, 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 January 1 to March 31, 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.

OPG's average sales price for the three months ended March 31, 2006 was 4.7¢/kWh compared to 4.3¢/kWh in the same period in 2005. The increase was due to the introduction of regulated prices and other related regulatory changes effective April 1, 2005, including a favourable change in the rebate mechanisms. This increase in sales price was partly offset by lower average Ontario spot market prices. The lower spot market prices were primarily due to lower electricity demand in Ontario.

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 of 5.2¢/kWh.

Electricity Generation

Total electricity generation during the three months ended March 31, 2006 from OPG's generating stations decreased to 28.4 TWh compared to 28.8 TWh during the same period in 2005. The decrease in generation was primarily a result of lower electricity demand in Ontario which impacted OPG's fossil-fuelled generation. The decrease was partially offset by increased generation from nuclear and the unregulated hydroelectric stations as a result of the return to service of Unit 1 at the Pickering A nuclear generating station and higher water levels, respectively.

OPG's results are impacted by changes in demand resulting from variations in seasonal weather conditions. The following table provides a comparison of Heating Degree Days for the three months ended March 31:

	Three Months Ended March 31	
	2006	2005
Heating Degree Days ¹ Quarter	1,664	1,977
Ten-year average	1,828	1,870

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

Heating Degree Days for the three months ended March 31, 2006 decreased compared to the same period in 2005 due to the unusually warm weather during the first quarter of 2006 and colder than average weather during the first quarter of 2005. The reduction in heating degree days contributed to the decrease in Ontario's electricity demand for the three months ended March 31, 2006 compared to the same period in 2005.

Cash Flow from Operations

Cash flow provided by operating activities for the three months ended March 31, 2006 was \$434 million compared to \$300 million during the same period in 2005. The increase was primarily due to higher revenue and earnings compared to the same period in 2005 and lower rebate payments in 2006. These increases were partially offset by an increase in pension fund contributions and changes in current payables and receivables.

Recent Developments

Lennox Generating Station

In March 2006, the OEB issued a decision approving a reliability must-run ("RMR") contract between OPG and the 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 stations that are not recovered through market revenues. The RMR contract is a cost-based contract that provides for regular payments, which are subject to adjustments for actual costs.

Labour Agreements

The Company maintains labour agreements with the Power Workers' Union ("PWU") and the Society of Energy Professionals (the "Society"). In January 2006, OPG and the PWU renewed their labour agreements for a period of three years, effective April 1, 2006. OPG and the Society renewed their labour agreement in December 2005. The agreement with the Society was effective January 1, 2006 for

a five year period. Approximately 90 per cent of OPG's regular labour force is covered by collective bargaining agreements.

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, are 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 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 that will continue 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.

OPG has established an initiative to assess and, as appropriate, prepare for the possible future life extension of OPG's existing nuclear facilities at Pickering B and Darlington. The project 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 first quarter of 2006, OPG completed runner upgrades at three unregulated hydroelectric generating stations which resulted in 14 MW of additional capacity.

Fossil-Fuelled Generating Assets

OPG's strategic objective, taking into account the Government's coal replacement policy, is to maintain the productive capability of its coal-fired 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.

In October 2005, OPG received a Shareholder Declaration from the Province instructing OPG's Board of Directors to convert the Thunder Bay generating station to run on natural gas. Under the declaration, the Province will 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 are required to ensure that OPG is able to record the conversion costs as an asset. The project is expected to be complete by December 2007.

Increasing OPG's Generating Capacity

OPG's strategy with respect to increasing its generating capacity is to expand, develop, and/or improve its hydroelectric generation 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 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").

Project expenditures for the three months ended March 31, 2006 were \$33 million and total expenditures to date were \$115 million. Site preparation work started in September 2005. Work is progressing at the outlet canal and the intake areas. In-water construction activities are scheduled to commence during the second quarter of 2006. The manufacturing of the tunnel boring machine is in progress with on-site assembly expected during the second and third quarter of 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.

Project expenditures for the three months ended March 31, 2006 were approximately \$4 million and life-to-date expenditures were \$7 million. The costs relate to activities for site preparation, excavation, engineering, project management and environmental approvals.

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, and to provide for interim financial guarantees or recoverable assistance for costs required to expedite the project prior to signing a definitive contract. PEC is negotiating a design-build contract for the facility with SNC Lavalin Power Ontario, and has entered into an agreement with this firm to cover the preliminary engineering and procurement.

Project expenditures to March 31, 2006, were approximately \$13 million.

ONTARIO ELECTRICITY MARKET TRENDS

Ontario's electricity demand averaged approximately 18,250 MW during the first quarter of 2006 compared to approximately 18,900 MW during the same period of 2005. The IESO has forecast 2006 peak demand of 25,502 MW.

The IESO has recently initiated the trial period of its Day-Ahead Commitment Process ("DACP"), which is intended to address reliability needs in Ontario's power system in 2006. The DACP will be in place on May 31, 2006, and is anticipated to continue to November 30, 2006.

The Ontario Energy Board announced that effective May 1, 2006, prices for Regulated Price Plan consumers who buy their electricity commodity from a utility will be 5.8¢/kWh for electricity use up to a certain threshold per month and 6.7¢/kWh for consumption above that threshold. For residential consumers, the monthly threshold for the lower price is set at 600 kilowatt hours ("kWh") during the summer season, from May to October and at 1,000 kWh for the winter season of November to April. The threshold for non-residential consumers that are eligible for the price plan will remain at 750 kWh per month throughout the year. The change in prices for Regulated Price Plan consumers does not impact OPG's revenue from its rate regulated and other generating stations.

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. Commencing in the first quarter of 2006, OPG has 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.

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 includes electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders

hydroelectric facilities. The Regulated – Hydroelectric business segment also includes ancillary revenues 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 other 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

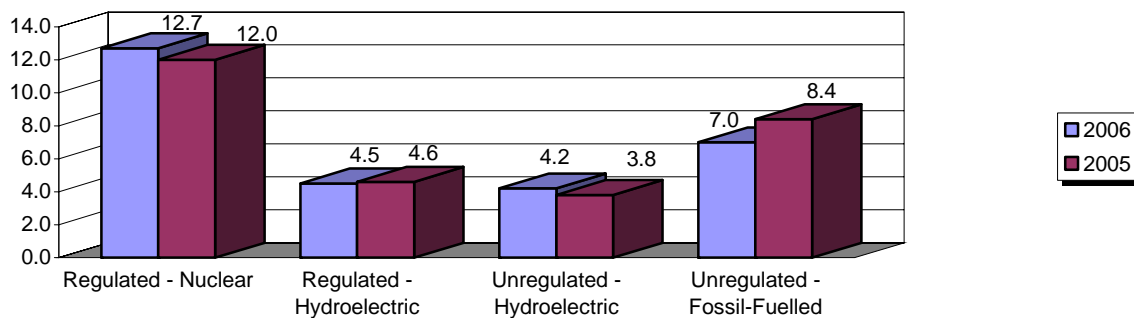
This section summarizes OPG’s key results by segment for the three months ended March 31, 2006 and 2005. Although the regulations pursuant to the *Electricity Restructuring Act, 2004* became effective commencing April 1, 2005, results for the first quarter of 2005 were reclassified according to the new 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:

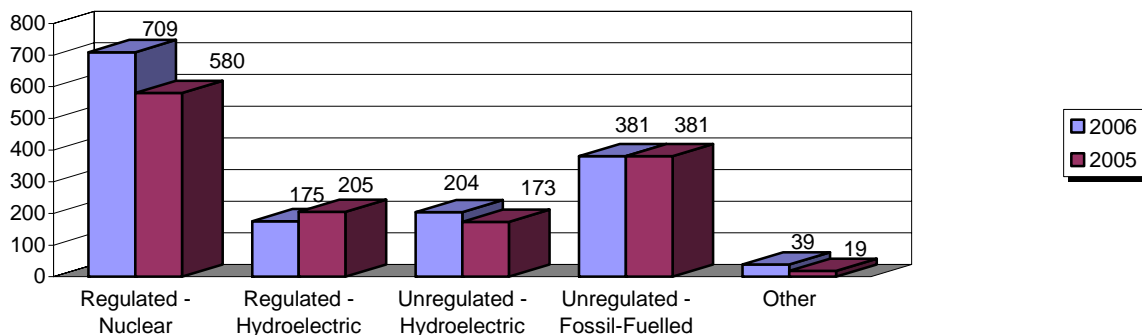
<i>(millions of dollars)</i>	Three Months Ended March 31	
	2006	2005
<i>Revenue, net of Market Power Mitigation Agreement rebate and revenue limit rebate</i>		
Regulated – Nuclear	709	580
Regulated – Hydroelectric	175	205
Unregulated – Hydroelectric	204	173
Unregulated – Fossil-Fuelled	381	381
Other	39	19
	1,508	1,358
<i>Income (loss) before interest and income taxes</i>		
Regulated – Nuclear	74	(16)
Regulated – Hydroelectric	81	112
Unregulated – Hydroelectric	128	106
Unregulated – Fossil-Fuelled	34	(203)
Other	26	(2)
	343	(3)
<i>Electricity Generation (TWh)</i>		
Regulated – Nuclear	12.7	12.0
Regulated – Hydroelectric	4.5	4.6
Unregulated – Hydroelectric	4.2	3.8
Unregulated – Fossil-Fuelled	7.0	8.4
Total electricity generation	28.4	28.8
<i>Nuclear unit capability factor¹ (per cent)</i>		
Darlington	94.6	93.9
Pickering A	91.2	99.8
Pickering B	78.6	84.3
<i>Equivalent forced outage rate (per cent)</i>		
Regulated – Hydroelectric	0.5	0.9
Unregulated – Hydroelectric	1.2	1.4
Unregulated – Fossil-Fuelled	10.8	14.2
<i>Availability (per cent)</i>		
Regulated – Hydroelectric	92.7	91.8
Unregulated – Hydroelectric	94.4	94.8
<i>Nuclear PUEC (\$/MWh)</i>	37.97	36.05
<i>Regulated – Hydroelectric OM&A expense per MWh (\$/MWh)</i>	4.67	3.91
<i>Unregulated – Hydroelectric OM&A expense per MWh (\$/MWh)</i>	8.57	7.63
<i>Unregulated – Fossil-Fuelled OM&A expense per MW (\$000/MW)</i>	53.9	44.4

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

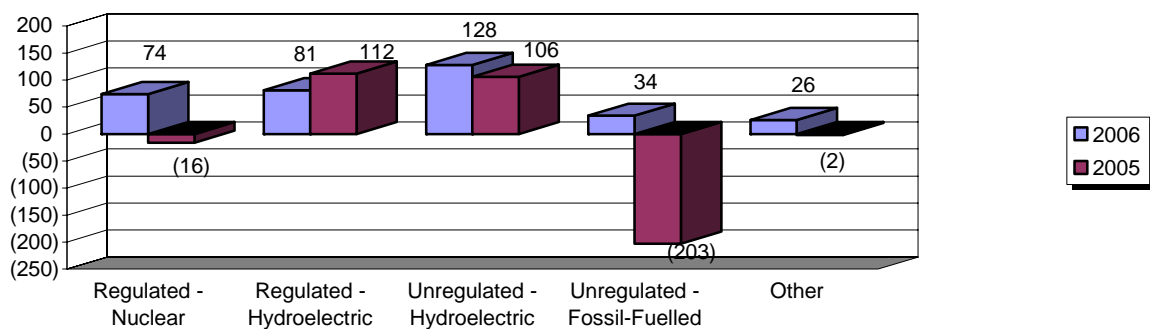
Electricity Production
Three Months Ended March 31
(TWh)



Revenue, Net of Revenue Limit Rebate and Market Power Mitigation Agreement
Rebate by Segment
Three Months Ended March 31
(millions of dollars)



Income (Loss) Before Interest and Income Taxes by Segment
Three Months Ended March 31
(millions of dollars)



During the first quarter of 2005, OPG recorded a \$202 million impairment loss related to its Lennox generating station.

Regulated – Nuclear Segment

<i>(millions of dollars)</i>	Three Months Ended March 31	
	2006	2005
Revenue before Market Power Mitigation Agreement rebate	709	740
Market Power Mitigation Agreement rebate	-	(160)
	709	580
Fuel expense	31	29
Gross margin	678	551
Operations, maintenance and administration	471	418
Depreciation and amortization	89	92
Accretion on fixed asset removal and nuclear waste management liabilities	123	117
Earnings on nuclear fixed asset removal and nuclear waste management funds	(89)	(71)
Property and capital taxes	10	11
Income (loss) before interest and income taxes	74	(16)

Revenue

<i>(millions of dollars)</i>	Three Months Ended March 31	
	2006	2005
Regulated generation sales	625	-
Spot market sales, net of hedging instruments	-	662
Market Power Mitigation Agreement rebate	-	(160)
Other	84	78
Total revenue	709	580

Regulated – Nuclear revenue was \$709 million for the three months ended March 31, 2006 compared to \$580 million during the same period in 2005, which was an increase of \$129 million or 22 per cent. The increase in revenue was primarily due to higher sales prices related to the introduction of regulated rates effective April 1, 2005, which exceeded OPG's average spot market price net of the Market Power Mitigation Agreement rebate for the same period in 2005. Revenue also increased as a result of higher electricity generation of 0.7 TWh during the first quarter of 2006 compared to the same period last year.

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. In the first quarter of 2005, OPG's average sales price, after taking into account the Market Power Mitigation Agreement rebate, was 4.3¢/kWh.

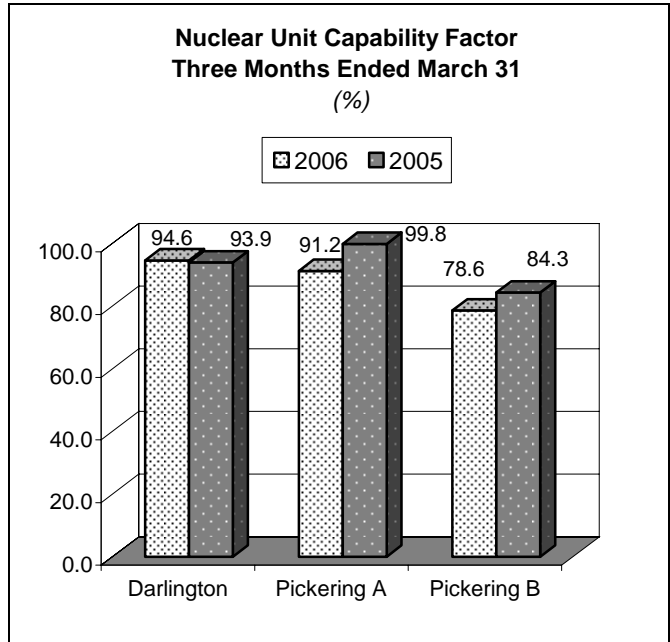
Volume

Electricity generation from stations in the Regulated – Nuclear segment for the three months ended March 31, 2006 was 12.7 TWh compared to 12.0 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. The increase in volume was partially offset by lower generation at the Pickering B generating station due to an extension of a planned outage.

The Darlington nuclear generating station's unit capability factor for the three months ended March 31, 2006 of 94.6 per cent was slightly greater than the 93.9 per cent for the same period in 2005, reflecting continued strong performance.

The Pickering A nuclear generating station's unit capability factor was 91.2 per cent, also reflecting very good performance. The decrease when compared to the same period in 2005 was primarily due to higher unplanned outage days during the first quarter of 2006.

The extension of the fall 2005 planned outage at the Pickering B nuclear generating station, which carried into 2006, contributed to a lower unit capability factor of 78.6 per cent during the first quarter of 2006 compared to 84.3 per cent for the same period in 2005.



Fuel Expense

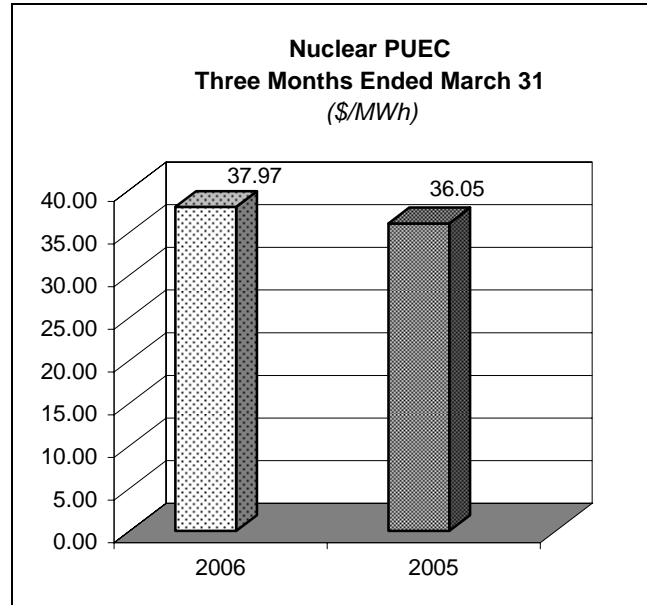
Fuel expense for the three months ended March 31, 2006 was \$31 million compared to \$29 million during the same period in 2005. The increase of \$2 million was primarily due to higher generation during the first quarter of 2006.

Operations, Maintenance and Administration

OM&A expenses for the three months ended March 31, 2006 were \$471 million compared to \$418 million during the same period in 2005. Pension and OPEB costs increased by \$33 million, primarily due to changes in economic assumptions related to discount rates and inflation. In addition, OM&A expenses for the three months ended March 31, 2006 included amortization of \$10 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, 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.

Nuclear PUEC for the three months ended March 31, 2006 increased to \$37.97/MWh compared to \$36.05/MWh during the same period in 2005. The increase was primarily due to higher pension and OPEB costs, and the amortization of the Pickering A return to service costs that were previously deferred.



Depreciation and Amortization

Depreciation and amortization expense for the three months ended March 31, 2006 was \$89 million compared to \$92 million for the same period in 2005. The decrease of \$3 million compared to the first quarter of 2005 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. During the first quarter of 2006, OPG extended the remaining service life of the Pickering B nuclear generating station to 2014 for depreciation purposes after a review of the life limiting components, taking into account recent station capacity factors. This reduces depreciation expense by approximately \$37 million annually over the period to 2009. In the fourth quarter of 2005, upon completion of the return to service of Unit 1 of the Pickering A nuclear generation station, OPG extended, for the purposes of calculating depreciation, the remaining service life of Unit 4 at the Pickering A generating station to 2021, from 2017. These decreases in depreciation were 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 \$123 million for the three months ended March 31, 2006 compared to \$117 million during the first quarter of 2005. The increase of \$6 million 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 March 31, 2006, OPG realized earnings of \$89 million on the nuclear fixed asset removal and nuclear waste management funds, compared to \$71 million during the first quarter of 2005. The increase of \$18 million was due primarily to a higher asset base and a higher Ontario Consumer Price Index compared to 2005, which impacts the guaranteed return on the Used Fuel Fund.

Regulated – Hydroelectric Segment

<i>(millions of dollars)</i>	Three Months Ended March 31	
	2006	2005
Revenue before the Market Power Mitigation Agreement rebate	175	270
Market Power Mitigation Agreement rebate	-	(65)
	175	205
Fuel expense	52	53
Gross margin	123	152
Operations, maintenance and administration	21	18
Depreciation and amortization	16	18
Property and capital taxes	5	4
Income before interest and income taxes	81	112

Revenue

<i>(millions of dollars)</i>	Three Months Ended March 31	
	2006	2005
Regulated generation sales ¹	163	-
Spot market sales, net of hedging instruments	-	260
Market Power Mitigation Agreement rebate	-	(65)
Variance accounts	3	-
Other	9	10
Total revenue	175	205

¹ Regulated generation sales includes revenue of \$46 million that OPG received at the Ontario spot market price for generation over 1,900 MWh in any hour during the period January 1 – March 31, 2006.

Regulated - Hydroelectric revenue was \$175 million for the three months ended March 31, 2006 compared to \$205 million during the same period in 2005. The decrease of \$30 million was primarily due to lower sales prices related to the introduction of regulated rates effective April 1, 2005, which were less than OPG's average spot market price net of the Market Power Mitigation Agreement rebate for the same period in 2005.

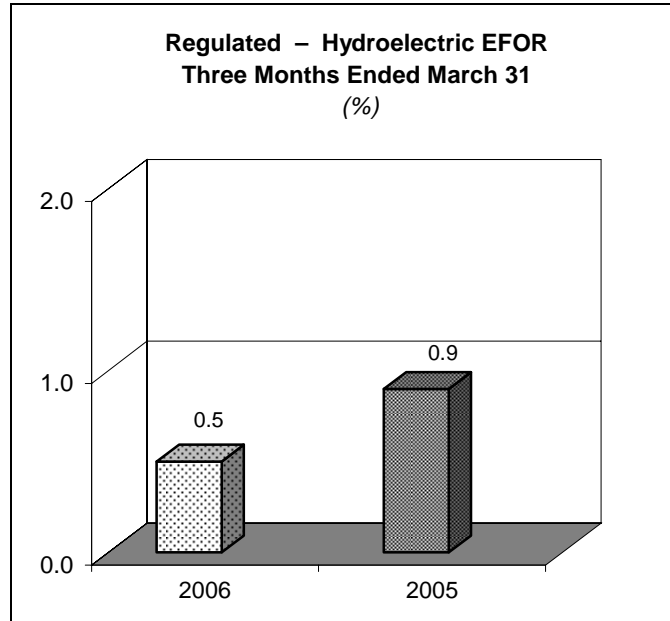
Electricity Prices

During the three months ended March 31, 2006, the average electricity sales price for the Regulated – Hydroelectric segment was 3.6¢/kWh. 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. During the three months ended March 31, 2005, the average spot market sales price was 4.3¢/kWh, after taking into account the Market Power Mitigation Agreement rebate.

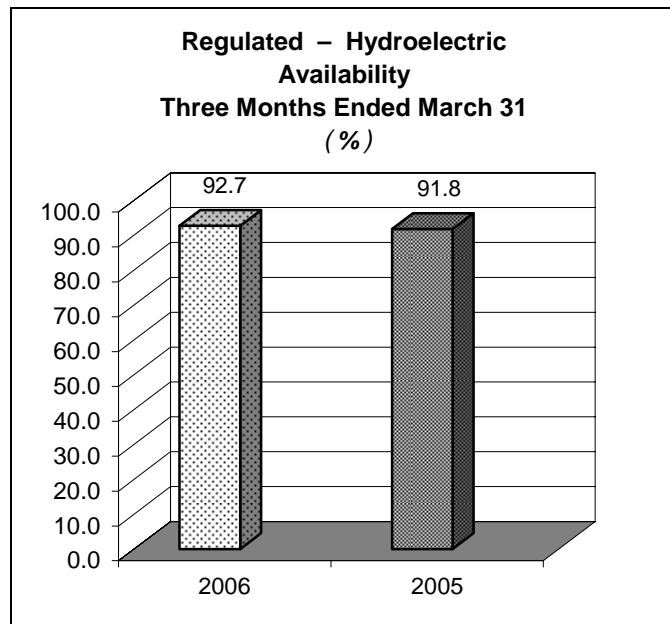
Volume

Electricity sales volume for the first quarter of 2006 was 4.5 TWh compared to 4.6 TWh in the first quarter of 2005. During the first quarter of 2006, 0.9 TWh related to production levels above 1,900 MWh in any hour. The decrease in volume was due to lower water levels in the Niagara and St. Lawrence rivers.

The equivalent forced outage rate for the Regulated – Hydroelectric stations was 0.5 per cent for the three months ended March 31, 2006 compared to 0.9 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 92.7 per cent for the three months ended March 31, 2006 compared to 91.8 per cent in the first quarter of 2005. The higher availability in the first quarter of 2006 was attributable to the improved EFOR performance and fewer planned maintenance outages during the three months ended March 31, 2006 compared to the same period in 2005.



Variance Accounts

OPG is required under a regulation pursuant to the *Electricity Restructuring Act, 2004* 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 March 31, 2006, OPG recorded an increase in OPG's regulatory asset of \$3 million and a corresponding addition to revenue, as a result of lower ancillary revenues compared to those forecasted.

Fuel Expense

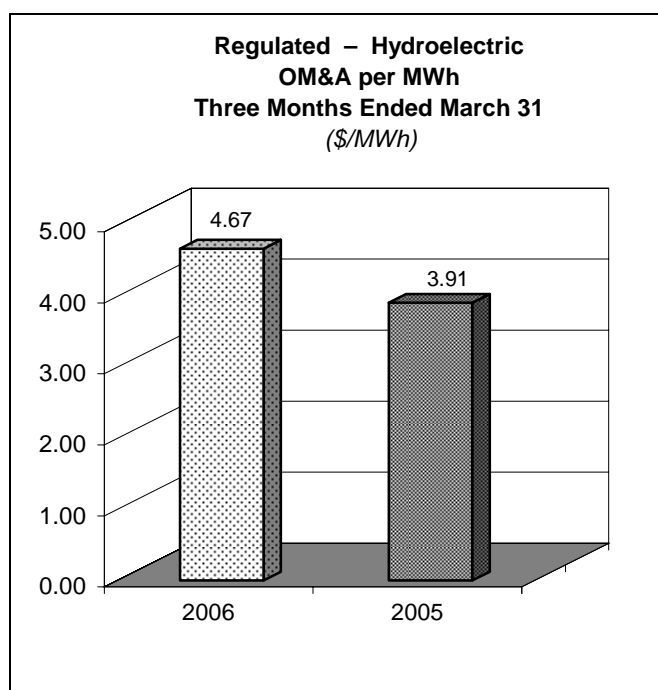
Fuel expense for the three months ended March 31, 2006 was \$52 million compared to \$53 million during the same period in 2005. OPG pays charges to the Province and the OEFC on gross revenue derived from the annual generation of electricity from its hydroelectric generating assets. The gross revenue 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 the quarter was a direct result of lower volumes compared to the same period in 2005.

Operations, Maintenance and Administration

OM&A expenses for the three months ended March 31, 2006 were \$21 million compared to \$18 million during the first quarter of 2005. The \$3 million increase was mainly due to increased pension and OPEB costs.

OM&A expense per MWh for the regulated hydroelectric stations increased to \$4.67/MWh in the first quarter of 2006 compared to \$3.91/MWh for the same period in 2005. This increase reflects higher OM&A expenses costs combined with lower generation.



Depreciation and Amortization

Depreciation expense for the three months ended March 31, 2006 was \$16 million compared to \$18 million in the same period in 2005.

Unregulated – Hydroelectric Segment

<i>(millions of dollars)</i>	Three Months Ended March 31	
	2006	2005
Revenue before the revenue limit rebate and the Market Power Mitigation Agreement rebate	224	231
Revenue limit rebate	(20)	-
Market Power Mitigation Agreement rebate	-	(58)
	204	173
Fuel expense	20	19
Gross margin	184	154
Operations, maintenance and administration	36	29
Depreciation and amortization	16	16
Property and capital taxes	4	3
Income before interest and income taxes	128	106

Revenue

<i>(millions of dollars)</i>	Three Months Ended March 31	
	2006	2005
Spot market sales, net of hedging instruments	219	224
Revenue limit rebate	(20)	-
Market Power Mitigation Agreement rebate	-	(58)
Other	5	7
Total revenue	204	173

Unregulated - Hydroelectric revenue was \$204 million for the three months ended March 31, 2006 compared to \$173 million for the same period in 2005. The increase of \$31 million was primarily due to a higher average sales price and higher electricity generation in the first quarter of 2006 compared to the same period in 2005.

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 during the first quarter of 2006. During the first quarter of 2005, OPG received the average electricity spot market sales price, but revenue was reduced by the Market Power Mitigation Agreement rebate.

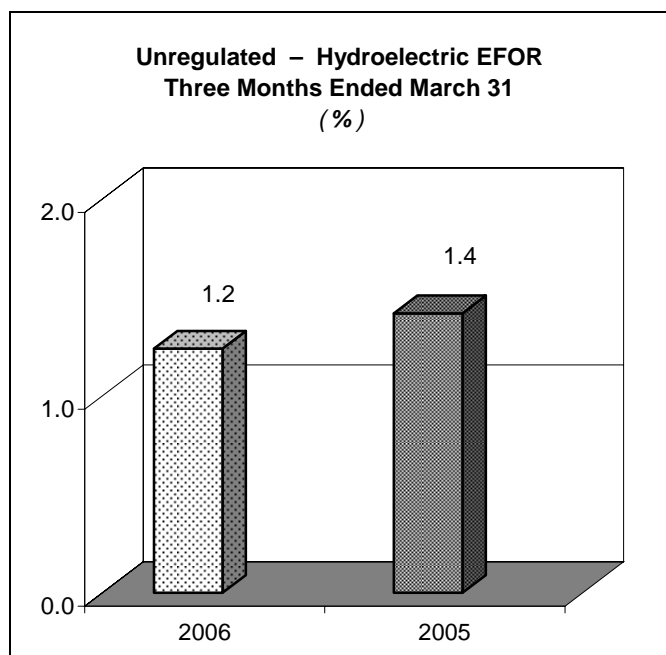
OPG's average sales price for its unregulated hydroelectric generation for the three months ended March 31, 2006 was 4.8¢/kWh, after taking into account the revenue limit rebate. The average sales price for the first quarter of 2005 was 4.4¢/kWh, net of the Market Power Mitigation Agreement rebate.

The higher average price during the three months ended March 31, 2006 compared to the same period in 2005 was due to the replacement of the Market Power Mitigation Agreement rebate with the revenue limit effective April 1, 2005, partially offset by the impact of lower average Ontario spot market prices.

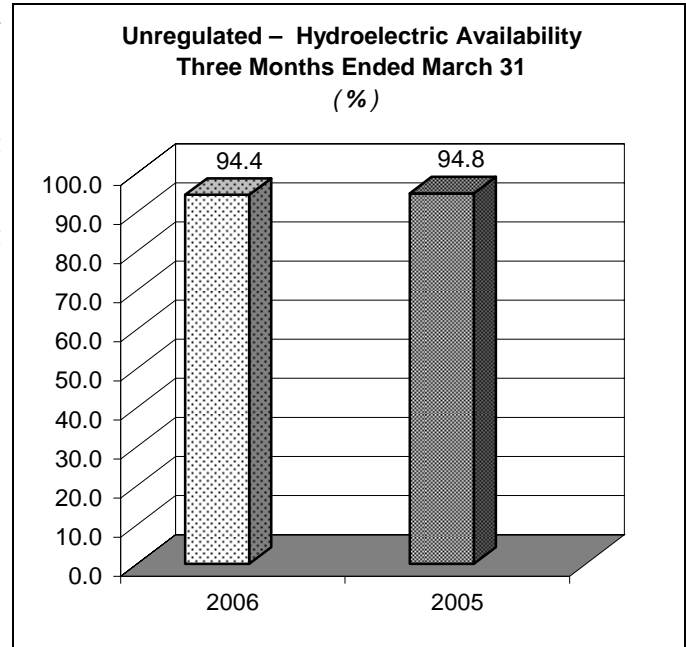
Volume

Electricity sales volume for the three months ended March 31, 2006 was 4.2 TWh compared to 3.8 TWh during the same period in 2005. The increase in volume was primarily due to higher water levels in northern and eastern Ontario.

The equivalent forced outage rate for the Unregulated – Hydroelectric stations was 1.2 per cent for the three months ended March 31, 2006 compared to 1.4 per cent during the first quarter of 2005. The EFOR reflects the continued strong performance at the stations within the unregulated hydroelectric segment.



The availability for the Unregulated – Hydroelectric stations was 94.4 per cent for the three months ended March 31, 2006 compared to 94.8 per cent in the first quarter of 2005. The marginally lower availability in the first quarter of 2006 compared to the same period in 2005 reflected an increase in planned outages to upgrade runners and overhaul units at several stations.



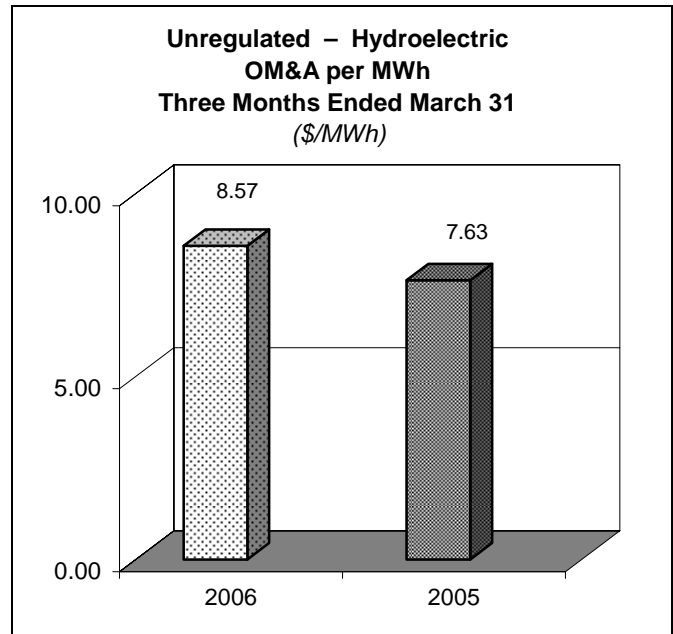
Fuel Expense

Fuel expense was \$20 million for the three months ended March 31, 2006 compared to \$19 million for the same period in 2005. Generating stations within this segment are subject to the gross revenue charge.

Operations, Maintenance and Administration

OM&A expenses for the three months ended March 31, 2006 were \$36 million compared to \$29 million for the same period in 2005. The increase of \$7 million was mainly due to higher pension and OPEB costs and the installation of upgraded runners at three stations.

OM&A expense per MWh for the unregulated hydroelectric stations increased to \$8.57/MWh in the first quarter of 2006 compared to \$7.63/MWh for the same period in 2005. This increase reflects higher OM&A expenses, partially offset by higher generation.



Depreciation and Amortization

Depreciation expense for the three months ended March 31, 2006 was unchanged at \$16 million compared to the same period in 2005.

Unregulated – Fossil-Fuelled Segment

<i>(millions of dollars)</i>	Three Months Ended March 31	
	2006	2005
Revenue before the revenue limit rebate and the Market Power Mitigation Agreement rebate	421	510
Revenue limit rebate	(40)	-
Market Power Mitigation Agreement rebate	-	(129)
	381	381
Fuel expense	175	209
Gross margin	206	172
Operations, maintenance and administration	115	108
Depreciation and amortization	51	58
Accretion on fixed asset removal	2	2
Property and capital taxes	4	5
Income (loss) before impairment of long-lived assets	34	(1)
Impairment of long-lived assets	-	202
Income (loss) before interest and income taxes	34	(203)

Revenue

<i>(millions of dollars)</i>	Three Months Ended March 31	
	2006	2005
Spot market sales, net of hedging instruments	378	489
Revenue limit rebate	(40)	-
Market Power Mitigation Agreement rebate	-	(129)
Other	43	21
Total revenue	381	381

Unregulated – Fossil-Fuelled revenue was unchanged at \$381 million for the three months ended March 31, 2006 when compared to the same period in 2005. Revenue for the first quarter of 2006 compared to the first quarter of 2005 was impacted by lower electricity generation, offset by a higher average sales price and receipt of revenue from the Lennox RMR contract. OPG received \$29 million related to the Lennox RMR contract during the first quarter 2006, of which \$13 million related to the period October 1, to December 31, 2005.

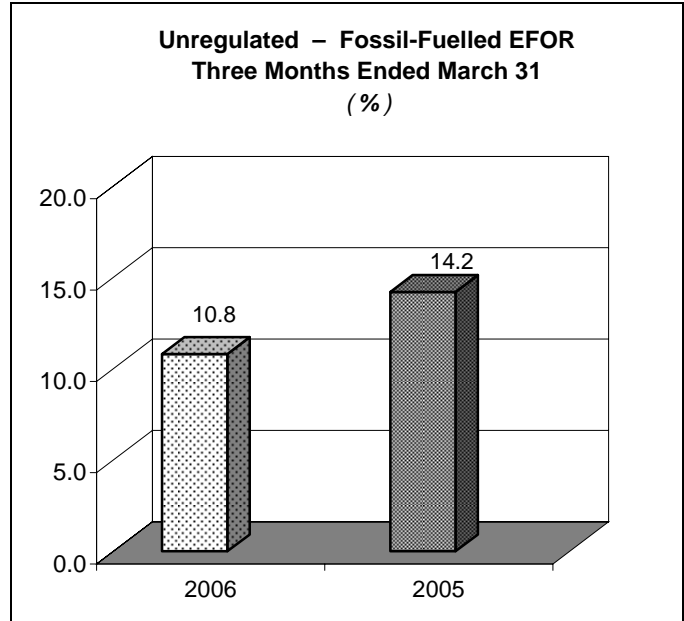
Electricity Prices

OPG's average sales price for its unregulated fossil-fuelled generation for the three months ended March 31, 2006 was 4.9¢/kWh after taking into account the revenue limit rebate. The average sales price for the same period in 2005 was 4.4¢/kWh, net of the Market Power Mitigation Agreement rebate. The higher average sales price during the three months ended March 31, 2006 compared to the same period in 2005 was due to the replacement of the Market Power Mitigation Agreement rebate with the revenue limit, effective April 1, 2005, partially offset by the impact of lower average Ontario spot market prices.

Volume

Electricity sales volume for the three months ended March 31, 2006 was 7.0 TWh compared to 8.4 TWh for the same period in 2005. The decrease in volume was primarily due to lower demand as a result of warmer weather, and higher generation from the nuclear and hydroelectric generating stations.

The equivalent forced outage rate for the fossil-fuelled generating stations was 10.8 per cent during the first quarter of 2006 compared to 14.2 per cent for the same period last year. This improvement was primarily due to improved equipment reliability at the Nanticoke generating station and the impact of closing the Lakeview generating station in April 2005.



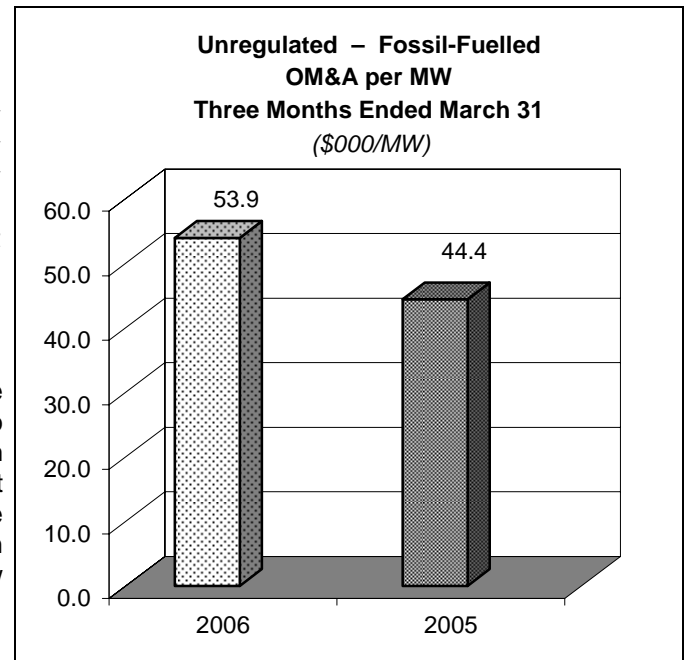
Fuel Expense

Fuel expense was \$175 million for the three months ended March 31, 2006 compared to \$209 million for the same period in 2005. The decrease of \$34 million was primarily due to reduced electricity sales volume.

Operations, Maintenance and Administration

OM&A expenses for the three months ended March 31, 2006 were \$115 compared to \$108 million for the same period in 2005. The increase of \$7 million was mainly due to higher pension and OPEB costs and higher expenditures on maintenance and other planned initiatives at the Nanticoke generating station. These increases were partially offset by lower OM&A expenditures due to the closure of the Lakeview generating station in April 2005.

OM&A expense per MW (\$/MW) for the unregulated fossil-fuelled stations increased to \$53,900/MW for the three months ended March 31, 2006 compared to \$44,400/MW for the first quarter of 2005. The increase reflects the higher OM&A expenses and the reduction in capacity due to the closure of the Lakeview generating station.



Depreciation and Amortization

Depreciation expense for the three months ended March 31, 2006 was \$51 million, compared to \$58 million for the same period in 2005. The decrease in depreciation expense was mainly due to the extension of the service life of the Nanticoke generating station, for the purpose 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. This reduced depreciation by \$10 million during the first quarter of 2006 compared to the first quarter of 2005. The impact of these factors on depreciation was partially offset by the impact of fixed asset additions.

Lennox Generating Station

In the first quarter of 2005, OPG recorded an impairment charge of \$202 million, which was the carrying value of the Lennox generating station. OPG was advised by the Province that it would not support an arrangement that would allow for the recovery of costs related to the carrying value of the Lennox generating station.

Other

<i>(millions of dollars)</i>	Three Months Ended March 31	
	2006	2005
Revenue	39	19
Operations, maintenance and administration	7	14
Depreciation and amortization	4	9
Property and capital taxes	2	(2)
Income (loss) before interest and income taxes	26	(2)

Other revenue was \$39 million for the three months ended March 31, 2006 compared to \$19 million for the same period in 2005. The increase of \$20 million was primarily due to increased trading revenue.

Net trading revenue for the first quarter of 2006 was \$22 million compared to \$2 million during the first quarter of 2005. The increase of \$20 million was primarily due to mark-to-market gains on interconnected sales contracts and higher margins on interconnected sales.

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 March 31, 2006 would have increased by \$49 million (March 31, 2005 – \$55 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 months ended March 31, 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 first quarter of 2006 was \$95 million compared to an income tax recovery of \$12 million for the same period in the prior year. The increase in the income tax expense was primarily due to higher earnings in 2006 compared to the same period in 2005. During the first quarter of 2006, the income tax expense was \$10 million lower than what would otherwise have been recorded, due to the application of the taxes payable method for the regulated segments.

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. OPG's 2006 results are also expected to reflect continued improvements in generating station performance and increased electricity generation.

In addition, OPG's future earnings are forecast to be impacted by a number of factors, including the closure of its coal-fired generating stations and the impact of the regulated prices established by the OEB.

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 and 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.

<i>(millions of dollars)</i>	Three Months Ended March 31	
	2006	2005
Cash and cash equivalents, beginning of the period	908	2
Cash flow provided by operating activities	434	300
Cash flow (used in) investing activities	(122)	(235)
Cash flow (used in) provided by financing activities	(301)	68
Net increase	11	133
Cash and cash equivalents, end of the period	919	135

Operating Activities

Cash flow provided by operating activities for the three months ended March 31, 2006 was \$434 million compared to \$300 million during the same period in 2005. The increase was primarily due to higher revenue and earnings compared to the same period in 2005 and lower rebate payments in 2006. These increases were partially offset by an increase in pension fund contributions and changes in current payables and receivables.

During the three months ended March 31, 2005, OPG made rebate payments of \$220 million under the Market Power Mitigation Agreement rebate. There were no rebate payments during the first quarter of 2006. The first revenue limit rebate payment of \$739 million relating to 2005 was paid in April 2006.

OPG made contributions of \$65 million to the pension plan during the three months ended March 31, 2006 compared to \$39 million during the same period in 2005. Pension contributions were higher compared to the three months ended March 31, 2005 to reflect increased funding requirements as a result of an updated actuarial valuation of the pension plan.

As required under the Ontario Nuclear Funds Agreement (“ONFA”), OPG made contributions of \$114 million to the nuclear fixed asset removal and nuclear waste management funds during the first quarters of 2006 and 2005.

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 and to maintain and improve service, reliability, safety and environmental performance. Capital expenditures during the three months ended March 31, 2006 were \$114 million compared with \$133 million during the same period in 2005. The decrease in capital expenditures was primarily due to the completion of the return to service of Unit 1 at the Pickering A nuclear generating station in November 2005, partially offset by higher capital expenditures related to the nuclear generating stations, the Niagara Tunnel project and the Portlands Energy Centre.

OPG’s anticipated capital expenditures for 2006 are approximately \$850 million, which include \$230 million for the Niagara Tunnel project, \$90 million for the Portlands Energy Centre, and \$50 million for the conversion of the Thunder Bay generating station from coal-fired to natural gas.

Included in the investing activity is OPG’s investment in deferred regulatory assets of \$10 million in the first quarter of 2006 compared to \$101 million during the same period in 2005. The lower investment in deferred regulatory assets during the three months ended March 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 364-day term \$1 billion revolving committed bank credit facility which is divided into two tranches – a \$500 million 364-day term tranche maturing May 23, 2006, and a \$500 million three-year term tranche maturing May 23, 2008. OPG received commitments from the banks to renew and extend the maturity dates to May 22, 2007 and May 22, 2009 for the respective tranches. 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 and as at March 31, 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 \$215 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 March 31, 2006, there were a total of \$143 million (December 31, 2005 – \$157 million) of Letters of Credit issued for the supplementary pension plans and collateral requirements to the LDCs.

In March 2005, the Company reached an agreement with the OEFC to obtain additional long-term financing for up to \$600 million. In April 2005, \$400 million was advanced under this facility for a seven-year term. The Company did not utilize the additional \$200 million available under the agreement, which expired on March 31, 2006.

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.

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 <i>(millions of dollars)</i>	As at	
	March 31 2006	December 31 2005
Assets		
Accounts receivable	339	538
Property, plant and equipment – net	11,351	11,412
Nuclear fixed asset removal and nuclear waste management funds	6,984	6,788
Regulatory assets	270	266
Liabilities		
Accounts payable and accrued charges	727	958
Revenue limit rebate payable	799	739
Long-term debt (including debt due within one year)	3,594	3,895
Fixed asset removal and nuclear waste management	8,865	8,759
Other post employment benefits and supplementary pension plans (long-term portion)	1,261	1,212

Accounts Receivable

As at March 31, 2006, accounts receivable were \$339 million compared to \$538 million as at December 31, 2005. The decrease of \$199 million was primarily due to lower sales volumes.

Property, Plant and Equipment – Net

Net property, plant and equipment as at March 31, 2006 was \$11,351 million compared to \$11,412 million as at December 31, 2005. The decrease of \$61 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 plants that are operated by OPG, as well as the Bruce A and B nuclear plants 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 ("Nuclear Funds"), 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 March 31, 2006, the Nuclear Funds on an amortized cost basis were \$6,984 million compared to \$6,788 million as at December 31, 2005. The increase of \$196 million during the first quarter of 2006 was primarily due to contributions by OPG to the funds and earnings on investments within the Nuclear Funds portfolio.

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 March 31, 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 March 31, 2006, there would be an amount due to the Province of \$403 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 March 31, 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 March 31, 2006, the Decommissioning Fund asset value on an amortized cost basis was \$4,170 million compared to a market value of \$4,782 million, the difference representing net unrealized gains of \$612 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 \$16 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 March 31, 2006, and the Decommissioning Fund was terminated under the ONFA, there would be an amount due to the Province of \$628 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 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 March 31, 2006, regulatory assets were \$270 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*, 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. During the first quarter of 2006, \$10 million of non-capital costs were deferred and amortization of \$10 million was recorded on the deferral account for the period ended March 31, 2006. OPG recorded an asset during the three months ended March 31, 2006 of \$4 million, primarily reflecting ancillary services revenue that was unfavorable compared to that forecasted for 2006.

Accounts Payable and Accrued Charges

Accounts payable and accrued charges as at March 31, 2006 were \$727 million compared to \$958 million as at December 31, 2005. The decrease of \$231 million was primarily due to the reduction in accrued interest on the OEFC bonds resulting from a payment made in the first quarter of 2006, reduced coal purchases over the winter months, and a reduction in other accrued charges primarily within the Regulated – Nuclear segment.

Revenue Limit Rebate Payable

The revenue limit rebate payable as at March 31, 2006 was \$799 million compared to \$739 million as at December 31, 2005. The increase of \$60 million during the first quarter of 2006 was related to the generation output subject to the revenue limit rebate in excess of \$47.00/MWh. The initial payment of the revenue limit rebate of \$739 million was paid in April 2006.

Long-Term Debt (including debt due within one year)

Long-term debt as at March 31, 2006 was \$3,594 million compared to \$3,895 as at December 31, 2005. The decrease in long-term debt was primarily due to a repayment of \$300 million of notes payable to the OEFC in March 2006.

Fixed Asset Removal and Nuclear Waste Management

The liability for fixed asset removal and nuclear waste management as at March 31, 2006 was \$8,865 million compared to \$8,759 million as at December 31, 2005. The increase of \$106 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 \$1,261 million as at March 31, 2006 compared to \$1,212 million as at December 31, 2005. The increase of \$49 million was due to costs recognized during the first quarter 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, 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 March 31, 2006, the average all-in cost of funds was 4.1 per cent and the pre-tax charges on sales to the trust were \$3 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 U.S. 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 loss on electricity derivative instruments and interest rate hedges was \$50 million as at March 31, 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 months ended March 31, 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 below 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 that will adversely impact OPG's earnings and cash flow from operations. To manage this risk, the Company seeks to maintain a balance between the commodity price risk inherent in its electricity production and plant fuel portfolios to the extent that trading liquidity in the relevant commodities markets provides the opportunity to do so in an economically justified manner. To manage the input risk, OPG has a fuel hedging program, which includes fixed price contracts for fossil and nuclear fuels.

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

	2006	2007	2008
Estimated generation output hedged ¹	93%	91%	91%
Estimated fuel requirements hedged ²	97%	90%	80%
Estimated nitric oxide (NO) emission requirement hedged ³	100%	81%	67%
Estimated sulphur dioxide (SO ₂) emission requirement hedged ³	100%	100%	100%

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

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

³ Represents the approximate portion of megawatt hours of expected fossil production for which OPG has purchased, been allocated or granted emission allowances and Emission Reduction Credits to meet OPG's obligations under Ontario Environmental 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 \$1.5 million and \$3.0 million during the three months ended March 31, 2006, compared to \$1.2 million and \$1.8 million during the three months ended March 31, 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 March 31, 2006 are within acceptable limits and does not anticipate any material effect on its results of operations or cash flows arising from potential defaults.

The following table provides information on credit risk from energy sales and trading activities as at March 31, 2006:

Credit Rating ¹	Number of Counterparties ²	Potential Exposure for Largest Counterparties		
		Potential Exposure ³ (millions of dollars)	Number of Counterparties	Counterparty Exposure (millions of dollars)
AAA to AA-	36	1	-	-
A+ to A-	46	54	3	35
BBB+ to BBB-	85	47	2	15
BB+ to BB-	24	69	4	50
Below BB-	35	34	1	30
Subtotal	226	205	10	130
IESO ⁴	1	497	1	497
Total	227	702	11	627

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 three months ended March 31, 2006 and at \$812 million during the three months ended March 31, 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, impacting 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. Recent wall thickness measurements of removed feeders and field inspections at the Pickering A generating station Units 1 and 4 have indicated that the location of the thinning is different than at Darlington, and the degree of thinning is greater than originally expected. Future inspections will be required to confirm the thinning rate at 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. The scale of these inspections has been increased to address the concern that the risk of cracking may be increasing in OPG's units. 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. Inspection of Pickering A Unit 4 in 2005 confirmed the presence of a single crack. Inspections of the other Pickering A and B units (including inspection of Pickering A Unit 1 in 2004 and Pickering B Units 5 and 6 in 2005) had not uncovered any further cracks. 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 costs.

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 Environment Policy commits OPG to meet all applicable legislative requirements and voluntary environmental commitments, integrate environmental factors into business planning and decision-making, and apply the precautionary principle in assessing risks to human health and the environment. This policy also commits OPG to maintain comprehensive environmental management systems ("EMSs") at our generating facilities consistent with the ISO 14001 standard.

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 currently proposed federal Climate Change Plan for any changes that may result from a change in the federal government during the first quarter of 2006 in order to assess any impact on OPG.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Changes in 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. Effective January 1, 2006, OPG changed its reportable business segments to separate the Unregulated Generation business segment into two reportable segments, identified as Unregulated – Fossil-Fuelled and Unregulated – Hydroelectric. In addition, OPG revised and extended the estimated service life of the Pickering B generating station for purposes of calculating depreciation after a review of the life limiting components of the station.

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*.

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.

<i>(millions of dollars)</i>	March 31 2006	December 31 2005	September 30 2005	June 30 2005
Revenue after revenue limit and Market Power Mitigation Agreement rebates	1,508	1,496	1,571	1,373
Income before extraordinary item	199	160	181	137
Income before extraordinary item per share	\$0.78	\$0.62	\$0.71	\$0.53
Net income	199	160	181	63
Net income per share	\$0.78	\$0.62	\$0.71	\$0.25

<i>(millions of dollars)</i>	March 31 2005	December 31 2004	September 30 2004	June 30 2004
Revenue after Market Power Mitigation Agreement rebate	1,358	1,215	1,212	1,141
Net (loss) income	(38)	34	(15)	(41)
Net (loss) income per share	\$(0.15)	\$0.13	\$(0.06)	\$(0.16)

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, the regulated rates, 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, commencing January 1, 2005, as required by regulation pursuant to the *Electricity Restructuring Act, 2004*;
- 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 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; and
- Higher depreciation expense related to the return to service of Unit 1 at the Pickering A generating station in the fourth quarter of 2005.

SUPPLEMENTAL EARNINGS MEASURES

In addition to providing net income in accordance with Canadian GAAP, OPG's MD&A, unaudited interim consolidated financial statements for the three months ended March 31, 2006 and 2005 and the notes thereto, present 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 (LOSS) (UNAUDITED)

Three Months Ended March 31

(millions of dollars except where noted)

	2006	2005
Revenue		
Revenue before revenue limit and Market Power Mitigation Agreement rebates	1,568	1,770
Revenue limit rebate (Note 15)	(60)	-
Market Power Mitigation Agreement rebate	-	(412)
	1,508	1,358
Fuel expense	278	310
Gross margin	1,230	1,048
Expenses		
Operations, maintenance and administration	650	587
Depreciation and amortization (Note 4)	176	193
Accretion on fixed asset removal and nuclear waste management liabilities	125	119
Earnings on nuclear fixed asset removal and nuclear waste management funds	(89)	(71)
Property and capital taxes	25	21
	887	849
Income before the following:	343	199
Impairment of long-lived assets (Note 4)	-	202
Income (loss) before interest and income taxes	343	(3)
Net interest expense	49	47
Income (loss) before income taxes	294	(50)
Income tax expenses (recoveries)		
Current	20	7
Future (Note 9)	75	(19)
	95	(12)
Net income (loss)	199	(38)
Basic and diluted income (loss) per common share (dollars)	0.78	(0.15)
Common shares outstanding (millions)	256.3	256.3

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (DEFICIT) (UNAUDITED)

Three Months Ended March 31

(millions of dollars)

	<u>2006</u>	<u>2005</u>
Retained earnings (deficit), beginning of period	261	(105)
Net income (loss)	<u>199</u>	<u>(38)</u>
Retained earnings (deficit), end of period	<u>460</u>	<u>(143)</u>

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Three Months Ended March 31

(millions of dollars)

	2006	2005
Operating activities		
Net income (loss)	199	(38)
Adjust for non-cash items:		
Depreciation and amortization	176	193
Accretion on fixed asset removal and nuclear waste management liabilities	125	119
Earnings on nuclear fixed asset removal and nuclear waste management funds	(89)	(71)
Pension cost	54	28
Other post employment benefits and supplementary pension plans	64	45
Future income taxes	75	(19)
Transition rate option contracts	(9)	(9)
Mark-to-market on energy contracts	(9)	2
Provision for used nuclear fuel	8	7
Impairment of long-lived assets	-	202
Regulatory assets and liabilities	7	-
Other	-	(1)
	601	458
Contributions to nuclear fixed asset removal and nuclear waste management funds	(114)	(114)
Expenditures on fixed asset removal and nuclear waste management	(28)	(14)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management	7	6
Contributions to pension fund	(65)	(39)
Expenditures on other post employment benefits and supplementary pension plans	(15)	(16)
Expenditures on restructuring (Note 13)	(5)	(5)
Net changes to other long-term assets and liabilities	(31)	(9)
Changes in non-cash working capital balances (Note 17)	84	33
Cash flow provided by operating activities	434	300
Investing activities		
Investment in regulatory assets (Note 5)	(10)	(101)
Investment in fixed assets	(114)	(133)
Net proceeds from sale (purchase) of long term investments	2	(1)
Cash flow (used in) investing activities	(122)	(235)
Financing activities		
Issuance of long-term debt (Note 7)	-	95
Repayment of long-term debt (Note 7)	(301)	(1)
Net increase (decrease) in short-term notes (Note 6)	-	(26)
Cash flow (used in) provided by financing activities	(301)	68
Net increase in cash and cash equivalents	11	133
Cash and cash equivalents, beginning of period	908	2
Cash and cash equivalents, end of period	919	135

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at <i>(millions of dollars)</i>	March 31	December 31
	2006	2005
Assets		
Current assets		
Cash and cash equivalents	919	908
Accounts receivable <i>(Note 3)</i>	339	538
Future income taxes	18	18
Fuel inventory	570	581
Materials and supplies	110	115
	1,956	2,160
Fixed assets <i>(Note 4)</i>		
Property, plant and equipment	15,278	15,172
Less: accumulated depreciation	3,927	3,760
	11,351	11,412
Other long-term assets		
Deferred pension asset	674	663
Nuclear fixed asset removal and nuclear waste management funds <i>(Note 8)</i>	6,984	6,788
Long-term materials and supplies	290	273
Regulatory assets <i>(Note 5)</i>	270	266
Long-term accounts receivable and other assets	58	61
	8,276	8,051
	21,583	21,623

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at <i>(millions of dollars)</i>	March 31 2006	December 31 2005
Liabilities		
Current liabilities		
Accounts payable and accrued charges <i>(Notes 13 and 14)</i>	727	958
Revenue limit rebate payable <i>(Note 15)</i>	799	739
Long-term debt due within one year <i>(Note 7)</i>	706	806
Deferred revenue due within one year	12	12
Income and capital taxes payable	96	81
	<u>2,340</u>	<u>2,596</u>
Long-term debt <i>(Note 7)</i>	<u>2,888</u>	<u>3,089</u>
Other long-term liabilities		
Fixed asset removal and nuclear waste management <i>(Note 8)</i>	8,865	8,759
Other post employment benefits and supplementary pension plans	1,261	1,212
Long-term accounts payable and accrued charges	173	183
Deferred revenue	141	144
Future income taxes	316	241
Regulatory liabilities <i>(Note 5)</i>	13	12
	<u>10,769</u>	<u>10,551</u>
Shareholder's equity		
Common shares	5,126	5,126
Retained earnings	460	261
	<u>5,586</u>	<u>5,387</u>
	<u>21,583</u>	<u>21,623</u>

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

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS FOR THE THREE MONTHS ENDED MARCH 31, 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* (Bill 100) received royal assent. A regulation made pursuant to that statute in February 2005 provides that OPG receive 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, and Pickering A and B, and Darlington nuclear generating stations.

OPG's regulated prices were determined by 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 all market participants in 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 unaudited consolidated interim 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.

Changes in Accounting Policies and Estimates

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 has 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.

Estimated Service Life of Pickering B Generating Station

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.

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. 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 March 31, 2006, the Company has recognized pre-tax charges of \$3 million (three months ended March 31, 2005 – \$2 million) on such sales at an average cost of funds of 4.1 per cent (three months ended March 31, 2005 – 2.9 per cent). As at March 31, 2006, OPG had sold receivables of \$300 million (December 31, 2005 – \$300 million) from its total portfolio of \$497 million (December 31, 2005 – \$668 million).

4. FIXED ASSETS

Depreciation and amortization expense for the three months ended March 31, 2006 and 2005 consists of the following:

<i>(millions of dollars)</i>	March 31 2006	March 31 2005
Depreciation and amortization	175	192
Nuclear waste management costs	1	1
	176	193

Interest capitalized to construction in progress at 6.0 per cent (three months ended March 31, 2005 – 6.0 per cent) during the three months ended March 31, 2006 was \$4 million (three months ended March 31, 2005 – \$8 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.

Lennox Generating Station

As a result of the Government’s “Request for Information/Request for Proposal for 2,500 MW of New Clean Generation and Demand Side Management Projects” released in September 2004 and the related contractual arrangements, future wholesale electricity market revenue is expected to be lower than previously anticipated. As a relatively high variable cost plant, the Lennox generating station will not be able to recover its fixed operating costs and its carrying value from the wholesale electricity market in the future. Given these factors, OPG had initiated discussions with the Province, with the expectation of entering into a contractual arrangement for the recovery of the annual fixed operating costs and the carrying value of the Lennox generating station. In March 2005, 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 stations that are not recovered through market revenues. As a result of the decision, OPG recorded \$29 million in revenue during the first quarter of 2006, of which approximately \$13 million relates to the period October 1, 2005 to December 31, 2005. The RMR contract is a cost-based contract that provides for regular payments, which are subject to adjustments for actual costs.

5. REGULATORY ASSETS AND LIABILITIES

The change in the regulatory assets and liabilities for the three months ended March 31, 2006 is as follows:

<i>(millions of dollars)</i>	December 31 2005	Additions	Amortization	March 31 2006
Regulatory assets				
Pickering A return to service costs	261	10	(10)	261
Ancillary services revenue variance account	5	4	-	9
Total regulatory assets	266	14	(10)	270
Regulatory liabilities				
Hydroelectric production variance account	4	-	-	4
Other	8	1	-	9
Total regulatory liabilities	12	1	-	13

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 March 31, 2006, the deferral account was \$261 million, consisting of non-capital costs of \$233 million relating to Unit 1, and \$19 million relating to Units 2 and 3, \$16 million of general return to service costs, and interest of \$7 million. The accumulated amortization as of March 31, 2006 was \$14 million.

As at December 31, 2005, the deferral account was \$261 million, consisting of non-capital costs of \$228 million relating to Unit 1, and \$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 an asset during the three months ended March 31, 2006 of \$4 million, reflecting ancillary services revenue that was unfavourable compared to that 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. OPG recorded an additional liability of \$1 million during the three months ended March 31, 2006.

Had OPG not accounted for the variances as a regulatory asset and liability, revenue for first quarter of 2006 would have been lower by \$3 million.

6. SHORT-TERM CREDIT FACILITIES

OPG's 364-day term \$1 billion revolving committed bank credit facility is divided into two tranches – a \$500 million 364-day term tranche maturing May 23, 2006, and a \$500 million three-year term tranche maturing May 23, 2008. OPG has received commitments from the banks to renew and extend the maturity dates to May 22, 2007 and May 22, 2009 for the respective tranches. The total credit facility will be used primarily as support for notes issued under OPG's commercial paper program. As of March 31, 2006, 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 \$215 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 March 31, 2006, there was a total of \$143 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 \$5 million (December 31, 2005 – \$19 million) relating to collateral requirements to the LDCs.

7. LONG-TERM DEBT

Long-term debt consists of the following:

<i>(millions of dollars)</i>	March 31 2006	December 31 2005
Notes payable to the Ontario Electricity Financial Corporation	3,395	3,695
Share of non-recourse limited partnership debt	199	200
	3,594	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	2,888	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 March 31, 2006 was \$119 million (three months ended March 31, 2005 – \$103 million), of which \$114 million relates to interest paid on long-term debt (three months ended March 31, 2005 – \$100 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 liability for fixed asset removal and nuclear waste management on a present value basis consists of the following:

<i>(millions of dollars)</i>	March 31 2006	December 31 2005
Liability for nuclear used fuel management	5,007	4,940
Liability for nuclear decommissioning and low and intermediate level waste management	3,665	3,627
Liability for non-nuclear fixed asset removal	193	192
Fixed asset removal and nuclear waste management liability	8,865	8,759

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

<i>(millions of dollars)</i>	March 31 2006	December 31 2005
Liability, beginning of period	8,759	8,339
Increase in liability due to accretion	125	476
Increase in liability due to nuclear used fuel and nuclear waste management variable expenses	9	34
Liabilities settled by expenditures on waste management	(28)	(90)
Liability, end of period	8,865	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 March 31, 2006 and December 31, 2005, consist of the following:

<i>(millions of dollars)</i>	Amortized Cost Basis		Fair Value	
	March 31 2006	December 31 2005	March 31 2006	December 31 2005
Decommissioning Fund	4,170	4,106	4,782	4,583
Due to Province – Decommissioning Fund	(16)	(7)	(628)	(484)
	4,154	4,099	4,154	4,099
Used Fuel Fund ¹	2,843	2,693	3,233	2,995
Due (to) from Province – Used Fuel Fund	(13)	(4)	(403)	(306)
	2,830	2,689	2,830	2,689
	6,984	6,788	6,984	6,788

¹ The Ontario NFWA Trust represents \$1,064 million as at March 31, 2006 (December 31, 2005 – \$1,003 million) of the Used Fuel Fund on an amortized cost basis.

9. INCOME TAXES

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. 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.

The following table summarizes the income statement and 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 for the three months ended March 31, 2006:

<i>(millions of dollars)</i>	As Stated	Liability Method
Future income tax expense	75	85
Current portion (assets)	(18)	(38)
Long-term portion (liability)	316	429

Had OPG continued to use the liability method for the regulated business, the future tax expense for the three months ended March 31, 2006 would have increased by \$10 million with a corresponding increase in the future income tax liability (year ended December 31, 2005 – \$157 million).

The amount of cash income taxes paid during the three months ended March 31, 2006 was \$8 million (three months ended March 31, 2005 – \$4 million).

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 months ended March 31, 2006 and 2005, are as follows:

<i>(millions of dollars)</i>	March 31 2006	March 31 2005
Registered pension plan	54	28
Supplementary pension plans	4	4
OPEB	60	41

11. FINANCIAL INSTRUMENTS

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

Trading activities and liquidity in the Ontario electricity market have been limited as companies are generally entering only into short-term contracts. As a result, forward pricing information for contracts may not accurately represent the cost to enter into these contracts. For Ontario-based contracts that are not entered into for hedging purposes, OPG established liquidity reserves against the fair market value of the assets and liabilities equal to the gain or loss on these contracts. These reserves decreased trading revenue by \$9 million during the three months ended March 31, 2006 (three months ended March 31, 2005 – increased by \$5 million). Contracts for transactions outside of Ontario continue to be carried on the consolidated balance sheets as assets or liabilities at fair value, with changes in fair value recorded in trading revenue as gains or losses.

Derivative Instruments Used for Hedging Purposes

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

<i>(millions of dollars except where noted)</i>	Notional Quantity	Terms	Fair Value	Notional Quantity	Terms	Fair Value
	March 31, 2006			December 31, 2005		
Gain (loss)						
Electricity derivative instruments	3.1 TWh	1-2 yrs	(54)	4.1 TWh	1-2 yrs	(125)
Foreign exchange derivative instruments	U.S. \$3	Apr/06	-	U.S. \$15	Jan/06	-
Interest rate hedges	400	1-15 yrs	2	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 March 31, 2006 was U.S. \$0.86 (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 ordinarily accounted for as hedges, however, a gain of approximately \$3 million (year ended December 31, 2005 – loss of \$5 million) was recorded to account for ineffectiveness in the hedges.

Derivative Instruments Not Used for Hedging Purposes

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

<i>(millions of dollars except where noted)</i>	Notional Quantity	Fair Value	Notional Quantity	Fair Value
	March 31, 2006		December 31, 2005	
Foreign exchange derivative	-	-	U.S. \$3	-
Commodity derivative instruments				
Assets	5.8 TWh	19	3.3 TWh	13
Liabilities	1.5 TWh	(23)	1.1 TWh	(37)
		(4)		(24)
Ontario market liquidity reserve		(12)		(3)
Total		(16)		(27)

Foreign exchange derivative instruments that are not designated as hedges have a weighted average exchange rate of U.S. \$0.85 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.

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 three months ended March 31, 2006, expenditures of \$1 million were recorded against the provision.

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 three months ended March 31, 2006 and the year ended December 31, 2005 are as follows:

<i>(millions of dollars)</i>	March 31 2006	December 31 2005
Liability, beginning of period	12	20
Restructuring charges	-	10
Payments	(5)	(18)
Liability, end of period	7	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 segment. No additional restructuring charge was recorded during the first quarter of 2006.

14. TRANSITION RATE OPTION CONTRACTS

Under regulation known as Transition – Generation Corporation Designated Rate Options (“TRO”), OPG has been required to provide transitional price relief since market opening to certain power customers for up to four years based on the consumption and average price paid by each customer during a reference period of July 1, 1999 to June 30, 2000. The TRO is treated as a hedge of generation revenue. The maximum length of the program is four years, which expires April 30, 2006.

Provisions totalling \$240 million on the TRO contracts were recorded in 2002 and 2003 based on the estimated future losses on these contracts. The provisions were determined at that time using management’s best estimates of the forward price curve for electricity, wholesale electricity market fees, impact of decontrol on these contracts, interruptions of volume, and the recovery of Market Power Mitigation Agreement rebates.

The change in the TRO contracts provision for the three months ended March 31, 2006 and the year ended December 31, 2006 are as follows:

<i>(millions of dollars)</i>	March 31 2006	December 31 2005
Provision, beginning of period	12	48
Decrease of provision during the period	(9)	(36)
Provision, end of period	3	12

15. REVENUE LIMIT REBATE

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, is subject to a revenue limit based on an average price of \$47.00/MWh (4.7¢/kWh). This revenue limit was originally established for a period of 13 months ending April 30, 2006, which 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 Ontario Power Authority will receive a revenue limit that is 0.5¢/kWh higher than the revenue limit applicable to OPG’s other generating assets. Revenues above these limits will be returned to the IESO for the benefit of consumers.

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

<i>(millions of dollars)</i>	March 31 2006	December 31 2005
Liability, beginning of period	739	-
Increase to provision during the period	60	739
Liability, end of period	799	739

16. 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. Commencing in the first quarter of 2006, OPG has 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.

Segment Income for Three Months Ended March 31, 2006 <i>(millions of dollars)</i>	Regulated		Unregulated			Total
	Nuclear	Hydro-electric	Hydro-electric	Fossil-Fuelled	Other	
Revenues						
Revenue	709	175	224	421	39	1,568
Revenue limit rebate	-	-	(20)	(40)	-	(60)
	709	175	204	381	39	1,508
Fuel expense	31	52	20	175	-	278
Gross margin	678	123	184	206	39	1,230
Operations, maintenance and administration	471	21	36	115	7	650
Depreciation and amortization	89	16	16	51	4	176
Accretion on fixed asset removal and nuclear waste management liabilities	123	-	-	2	-	125
Earnings on nuclear fixed asset removal and nuclear waste management funds	(89)	-	-	-	-	(89)
Property and capital taxes	10	5	4	4	2	25
Income before interest and income taxes	74	81	128	34	26	343

Segment (Loss) Income for Three Months Ended March 31, 2005 <i>(millions of dollars)</i>	Regulated		Unregulated			Total
	Nuclear	Hydro-electric	Hydro-electric	Fossil-Fuelled	Other	
Revenues						
Revenue	740	270	231	510	19	1,770
Market Power Mitigation Agreement rebate	(160)	(65)	(58)	(129)	-	(412)
	580	205	173	381	19	1,358
Fuel expense	29	53	19	209	-	310
Gross margin	551	152	154	172	19	1,048
Operations, maintenance and administration	418	18	29	108	14	587
Depreciation and amortization	92	18	16	58	9	193
Accretion on fixed asset removal and nuclear waste management liabilities	117	-	-	2	-	119
Earnings on nuclear fixed asset removal and nuclear waste management funds	(71)	-	-	-	-	(71)
Property and capital taxes	11	4	3	5	(2)	21
(Loss) income before the following:	(16)	112	106	(1)	(2)	199
Impairment of long-lived assets	-	-	-	202	-	202
(Loss) income before interest and income taxes	(16)	112	106	(203)	(2)	(3)

	Regulated		Unregulated			Total
	Nuclear	Hydro-electric	Hydro-electric	Fossil-Fuelled	Other	
<i>(millions of dollars)</i>						
Selected Balance Sheet Information						
March 31, 2006						
Segment property, plant and equipment, net	3,113	4,072	3,073	498	595	11,351
December 31, 2005						
Segment property, plant and equipment, net	3,156	4,054	3,076	531	595	11,412
Selected Cash Flow Information						
March 31, 2006						
Capital expenditures	41	34	11	14	14	114
March 31, 2005						
Capital expenditures	95	17	7	10	4	133

17. CHANGES IN NON-CASH WORKING CAPITAL BALANCES

	Three Months Ended March 31	
<i>(millions of dollars)</i>	2006	2005
Accounts receivable	197	(89)
Fuel inventory	11	99
Materials and supplies	5	(14)
Market Power Mitigation Agreement rebate payable	-	192
Revenue limit rebate payable	60	-
Accounts payable and accrued charges	(204)	(163)
Income and capital taxes payable	15	8
	84	33

18. 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.