ONTARIOPOWER GENERATION

News
from Ontario Power Generation

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# ONTARIO POWER GENERATION REPORTS 2007 THIRD QUARTER FINANCIAL RESULTS

[Toronto]: Ontario Power Generation Inc. ("OPG" or the "Company") today reported its financial and operating results for the third quarter and nine months ended September 30, 2007. Net income for the three months ended September 30, 2007 was $113 million compared to net income of $167 million for the same period in 2006. For the nine months ended September 30, 2007, net income was $409 million compared to $509 million for the same period last year.

"Over the first nine months of 2007, performance, in terms of production and reliability of OPG's fossil and hydroelectric stations as well as the Darlington nuclear station, has continued to improve. The Pickering A and B stations have experienced a number of operational and technical issues that have unfavourably affected their performance. Our financial results are somewhat lower than in 2006 as a result of lower generation at the Pickering A station, and higher planned maintenance expenditures on the nuclear and fossil stations," said President and CEO Jim Hankinson.

"Under the system established by the Ontario government for setting the prices received for electricity production from OPG's regulated assets, the Company plans to submit a rate application to the Ontario Energy Board during the fourth quarter of 2007," said Mr. Hankinson. OPG's regulated assets include its nuclear stations, and the hydroelectric stations on the Niagara and St. Lawrence rivers.

During the third quarter of 2007, OPG received an average price of 4.7¢/kilowatt hour ("kWh") for the output from all of its generating stations. This was lower than the weighted average Ontario spot market electricity price of 5.1¢/kWh during the quarter. In comparison, during the third quarter of 2006, OPG received an average price of 4.7¢/kWh compared to the weighted average Ontario spot market electricity price of 4.9¢/kWh. OPG's average price reflects regulated prices for production from its nuclear and baseload hydroelectric generating assets, as well as spot market prices, subject to a revenue limit, for the majority of its remaining production.

Electricity generation of 26.2 terawatt hours ("TWh") in the third quarter of 2007 was marginally lower than third quarter 2006 production of 27.0 TWh. Nuclear production of 10.8 TWh was lower than third quarter 2006 production of 12.9 TWh mainly due to unplanned outages at the Pickering A station. Hydroelectric production of 7.2 TWh was marginally higher than production of 6.8 TWh in 2006. Production from OPG's fossil stations of 8.2 TWh in the third quarter of 2007 reflected an increase over third quarter 2006 production of 7.3 TWh. For the nine months ended September 30, 2007, total production from OPG's generating stations was 80.4 TWh compared to 80.9 TWh for the same period in 2006.

Availability factors at OPG's fossil and hydroelectric stations and the Darlington nuclear station remain near historically high levels. As a result of unplanned outages at the Pickering A and B nuclear stations, availability factors for the third quarter and nine months ended September 30, 2007 were lower than the same periods in 2006.

Earnings during the three months ended September 30, 2007 were primarily affected by lower generation from OPG's Pickering A nuclear station, and higher nuclear and fossil maintenance expenses. This reduction was partly offset by higher fossil and unregulated hydroelectric generation, and an increase in non-electricity generation revenue.

Earnings during the nine months ended September 30, 2007 were mainly affected by lower generation from OPG's Pickering nuclear stations, and higher nuclear and fossil maintenance expenses. This effect was partly offset by an increase in earnings from the nuclear waste management funds, an increase in non-electricity generation revenue, higher fossil generation, and lower depreciation expense primarily due to the extension of the service lives of the coal-fired generating stations for accounting purposes.

During the third quarter of 2007, OPG continued to progress the following electricity generation projects aimed at increasing Ontario's long-term electricity supply:

- The 10.4 kilometre Niagara tunnel will increase the amount of water flowing to existing turbines at the Sir Adam Beck generating stations in Niagara Falls. At September 30, 2007, the tunnel boring machine had advanced 1,028 metres. Progress of the tunnel boring machine through a fractured rock formation has been slower than expected. Uncertainty remains with respect to the schedule until the tunnel boring machine advances sufficiently beyond the St. David's Gorge (to approximately 2,300 metres) and establishes consistent tunneling performance. The project is still expected to be completed within the budgeted cost estimate of $985 million;
- Construction of a new 12.5 megawatt ("MW") Lac Seul hydroelectric generating station on the English River which has been delayed as a result of various difficulties including the replacement of a major sub-contractor. Project completion is now expected to be in the second quarter of 2008. Total project costs are still expected to be within the budgeted cost estimate of $47 million;
- Construction of the Portlands Energy Centre ("PEC"), a limited partnership between OPG and TransCanada Energy Ltd is progressing well. The project remains on schedule and the station is expected to be operating in a simple cycle mode with a capacity of up to 340 MW beginning June 1, 2008, and providing up to 550 MW of power in a combined cycle mode in the second quarter of 2009;
- OPG is undertaking a business case examination for the potential refurbishment and life extension of its Pickering B nuclear station. This examination includes a plant condition assessment, an Environmental Assessment, and an integrated safety review. OPG plans to make a recommendation on the feasibility of this project to its Board of Directors. Work concerning the potential refurbishment of the Darlington nuclear station started in the third quarter of 2007; and
- OPG initiated a federal approval process with the Canadian Nuclear Safety Commission ("CNSC") during 2006 for new nuclear generating units on the site of its Darlington nuclear generating station. In 2007, OPG has implemented initiatives in support of an environmental assessment, submitted a project description to the CNSC, and is undertaking a technology assessment.

## FINANCIAL AND OPERATIONAL HIGHLIGHTS

| (millions of dollars – except where noted) | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2007** | **2006** | **2007** | **2006** |
| *Earnings* | | | | |
| Revenue after revenue limit rebate | **1,421** | 1,435 | **4,318** | 4,288 |
| Fuel expense | **336** | 310 | **962** | 831 |
| Gross margin | **1,085** | 1,125 | **3,356** | 3,457 |
| Operations, maintenance and administration | **689** | 628 | **2,159** | 1,946 |
| Other expenses | **257** | 279 | **676** | 853 |
| Income tax expenses | **26** | 51 | **112** | 149 |
| Net income | **113** | 167 | **409** | 509 |
| *Cash flow* | | | | |
| Cash flow provided by operating activities | **248** | 307 | **723** | 306 |
| *Electricity Generation (TWh)* | | | | |
| Regulated – Nuclear | **10.8** | 12.9 | **33.5** | 36.8 |
| Regulated – Hydroelectric | **4.4** | 4.6 | **13.7** | 13.5 |
| Unregulated – Hydroelectric | **2.8** | 2.2 | **10.6** | 11.0 |
| Unregulated – Fossil-Fuelled | **8.2** | 7.3 | **22.6** | 19.6 |
| Total electricity generation | **26.2** | 27.0 | **80.4** | 80.9 |
| *Average electricity sales price [1] (¢/kWh)* | | | | |
| Regulated – Nuclear [1] | **4.9** | 4.9 | **4.9** | 4.9 |
| Regulated – Hydroelectric [1] | **3.5** | 3.6 | **3.5** | 3.5 |
| Unregulated – Hydroelectric [2] | **4.7** | 4.6 | **4.7** | 4.7 |
| Unregulated – Fossil-Fuelled [2] | **4.9** | 4.8 | **4.9** | 4.8 |
| OPG average sales price | **4.7** | 4.7 | **4.6** | 4.6 |
| *Nuclear unit capability factor (per cent)* | | | | |
| Darlington | **96.3** | 94.5 | **91.4** | 89.8 |
| Pickering A | **-** | 82.9 | **41.5** | 86.1 |
| Pickering B | **82.0** | 87.5 | **74.7** | 79.2 |
| *Equivalent forced outage rate (per cent)* | | | | |
| Unregulated– Fossil-Fuelled | **10.5** | 11.7 | **11.2** | 12.5 |
| *Availability (per cent)* | | | | |
| Regulated – Hydroelectric | **97.4** | 95.9 | **94.2** | 93.1 |
| Unregulated– Hydroelectric | **92.2** | 89.2 | **94.2** | 92.9 |

1 After April 1, 2005, electricity generation from stations in the Regulated – Nuclear segment receives a fixed price of 4.95¢/kWh and electricity generation from stations in the Regulated – Hydroelectric segment receives 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 Eighty-five per cent of the electricity generation from unregulated stations, excluding the Lennox generating station and other contract volumes, is subject to a revenue limit. During the period from April 1, 2005 to April 30, 2006, the revenue limit was set at 4.7¢/kWh. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh and increased to 4.7¢/kWh effective May 1, 2007.

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 as at and for the three and nine months ended September 30, 2007, can be accessed on OPG's website (www.opg.com), the Canadian Securities Administrators' website (www.sedar.com), or can be requested from the Company.


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ONTARIOPOWER GENERATION

# 2007 THIRD QUARTER REPORT

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This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. ("OPG" or the "Company") as at and for the three and nine months ended September 30, 2007. For a complete description of OPG's corporate strategies, risk management initiatives, 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, 2006. Certain of the 2006 comparative amounts have been reclassified to conform to the 2007 presentation. 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 November 15, 2007.

## 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.

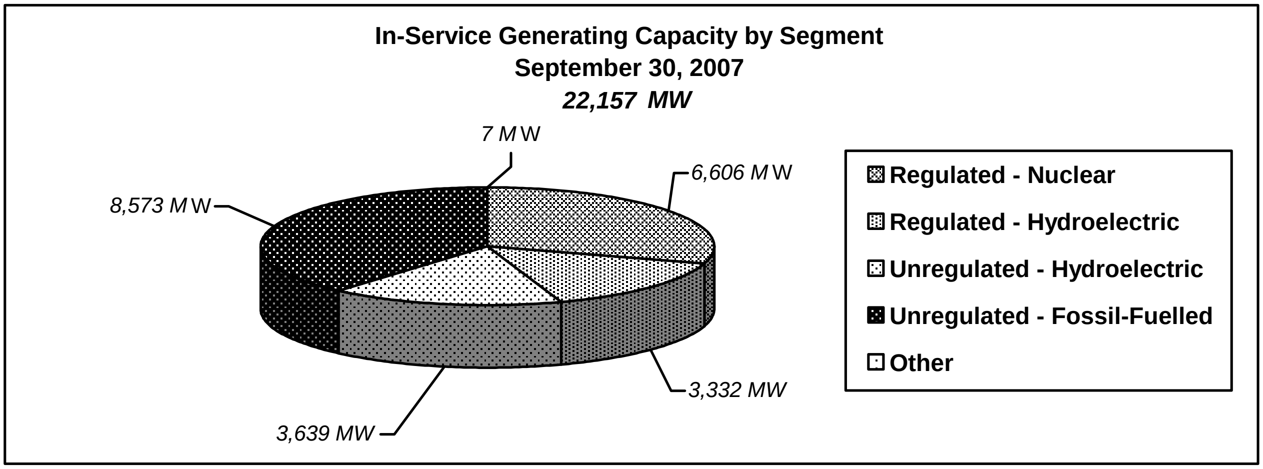
All forward-looking statements involve inherent assumptions, risks and uncertainties and, therefore, could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's fuel costs and availability, asset performance, nuclear decommissioning and waste management, closure of coal-fired generating stations, refurbishment of existing facilities, development and construction of new facilities, pension and other post employment benefit ("OPEB") obligations, income taxes, spot electricity market prices, the ongoing evolution of the Ontario electricity industry, environmental and other regulatory requirements, the weather, and the developments with respect to Asset-Backed Commercial Paper ("ABCP"). 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 established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the "Province").

At September 30, 2007, OPG's electricity generating portfolio had an in-service capacity of 22,157 megawatts ("MW"). OPG's electricity generating portfolio consists of three nuclear generating stations, five fossil-fuelled generating stations, 64 hydroelectric generating stations and three wind generating stations (including a 50 per cent interest in the Huron Wind joint venture). In addition, OPG, ATCO Power Canada Ltd. and ATCO Resources Ltd. co-own the Brighton Beach 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 the nuclear facilities that the Company operates 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.




## RATE REGULATION

A regulation was introduced pursuant to the *Electricity Restructuring Act, 2004* (Ontario), which provides that, effective April 1, 2005, OPG receives regulated prices for electricity generated from most of its baseload hydroelectric and all of the nuclear facilities that it operates. This comprises electricity generated from the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and Pickering A and B and Darlington nuclear facilities.

The regulated price received by OPG for the first 1,900 megawatt hours ("MWh") of production from the regulated hydroelectric facilities in any hour is $33.00/MWh (3.3¢/kWh). As an incentive to encourage maximum hydroelectric electricity production during peak demand periods, any production from these regulated hydroelectric facilities above 1,900 MWh in any hour receives the Ontario electricity spot market price. The regulated price received by OPG for production from the nuclear facilities is $49.50/MWh (4.95¢/kWh). These regulated prices were established by the Province, based on a revenue requirement taking into account a forecast of production volumes and total operating costs, and a return on rate base, which assumed an average five per cent return on equity. Rate base is a regulatory construct that represents the average net level of investment in regulated fixed assets and an allowance for working capital. These initial prices took effect April 1, 2005, and are expected to remain in effect until at least March 31, 2008, after which time the Ontario Energy Board (the "OEB") will assume responsibility for establishing new regulated prices.

The regulation directed OPG to establish variance accounts for costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecast information provided to the Province for the purposes of establishing regulated prices. Variance accounts have been established for differences in hydroelectric electricity production due to differences between forecast and actual water conditions; unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear facilities; changes to revenues for ancillary services 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 non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A nuclear generating station.

An amendment to the regulation was made by the Province in February 2007. The amendment clarified certain aspects of the regulation and directed OPG to establish a deferral account related to certain changes in its liabilities for nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management. The amendment directed OPG to establish a deferral account to record, up to the effective date of the OEB's first order establishing regulated prices, the revenue requirement impact of any changes in its nuclear liabilities arising from a new reference plan, approved after April 1, 2005, in accordance with the terms of the Ontario Nuclear Funds Agreement ("ONFA").

The amendment also clarified that the OEB must ensure that OPG recovers, through future regulated prices, all capital and non-capital costs incurred by OPG in order to increase the output of, refurbish, or add operating capacity to a regulated facility, if these costs are within budgets approved by OPG's Board of Directors prior to the OEB's first order establishing regulated prices, or if the OEB is satisfied that these costs were prudently incurred.

OPG plans to file an application in November 2007 with the OEB for new payment amounts for its regulated facilities effective April 1, 2008, for a twenty-one month period. OPG invited stakeholders to participate in consultation sessions, which occurred in early November, in advance of filing this application. The intent of the consultations was to inform stakeholders about OPG's regulated facilities and to discuss issues related to the application for new payment amounts. OPG will seek a rate of return consistent with the scope and type of business risks associated with reliably operating and responsibly increasing production from its regulated assets.

The production from OPG's other generating assets remains unregulated and continues to be sold at the Ontario electricity spot market price. However, 85 per cent of the generation output from OPG's other generating assets, excluding the Lennox generating station and forward sales as of January 1, 2005, is subject to a revenue limit. The output from a generating unit where there has been a fuel conversion and the incremental output from a generating station where there has been a refurbishment or expansion of these assets are also excluded from the output covered by the revenue limit. In addition, until the Transition – Generation Corporation Designated Rate Options ("TRO") expired on April 30, 2006, volumes sold under such options were excluded from the revenue limit rebate.

The revenue limit, which was originally established for a period of 13 months ending April 30, 2006, was subsequently extended for an additional three years. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh. On May 1, 2007, the revenue limit returned to 4.7¢/kWh and will increase to 4.8¢/kWh effective May 1, 2008. In addition, beginning April 1, 2006, volumes sold under a Pilot Auction administered by the Ontario Power Authority ("OPA") are subject to a revenue limit that is 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Revenues above these limits are returned to the Independent Electricity System Operator ("IESO") for the benefit of consumers.

## HIGHLIGHTS

### Overview of Results

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

| | **Three Months Ended September 30** | | **Nine Months Ended September 30** | |
|---|---|---|---|---|
| *(millions of dollars)* | **2007** | **2006** | **2007** | **2006** |
| *Revenue* | | | | |
| Revenue before revenue limit rebate | **1,481** | 1,494 | **4,494** | 4,436 |
| Revenue limit rebate | **(60)** | (59) | **(176)** | (148) |
| | **1,421** | 1,435 | **4,318** | 4,288 |
| *Earnings* | | | | |
| Income before interest and income taxes | **176** | 265 | **623** | 803 |
| Net interest expense | **37** | 47 | **102** | 145 |
| Income before income taxes | **139** | 218 | **521** | 658 |
| Income tax expenses | **26** | 51 | **112** | 149 |
| Net income | **113** | 167 | **409** | 509 |
| *Electricity production (TWh)* | **26.2** | 27.0 | **80.4** | 80.9 |
| *Cash flow* | | | | |
| Cash flow provided by operating activities | **248** | 307 | **723** | 306 |

Net income for the three months ended September 30, 2007 was $113 million compared to $167 million for the same period in 2006, a decrease of $54 million. Income before income taxes for the three months ended September 30, 2007 was $139 million compared to income before income taxes during the same period in 2006 of $218 million, a decrease of $79 million.

Net income for the nine months ended September 30, 2007 was $409 million compared to $509 million for the same period in 2006, a decrease of $100 million. Income before income taxes for the nine months ended September 30, 2007 was $521 million compared to income before income taxes during the same period in 2006 of $658 million, a decrease of $137 million.

The following is a summary of the factors impacting OPG's results for the three and nine months ended September 30, 2007 compared to results for the same periods in 2006, on a before-tax basis:

| *(millions of dollars – before tax)* | **Three Months** | **Nine Months** |
|---|---|---|
| **Income before income taxes for the periods ended September 30, 2006** | **218** | **658** |
| Changes in gross margin | | |
| Change in electricity generation by segment: | | |
| Regulated – Nuclear | (99) | (158) |
| Regulated – Hydroelectric | (4) | 4 |
| Unregulated – Hydroelectric | 25 | (18) |
| Unregulated – Fossil-Fuelled | 16 | 58 |
| Increase in fuel expense primarily due to higher costs for coal consumed in production | (2) | (20) |
| Increase in non-electricity generation revenue | 15 | 62 |
| Other changes in gross margin | 9 | (29) |
| | (40) | (101) |
| Increase in operations and maintenance primarily due to higher maintenance expenditures related to OPG's nuclear and fossil-fuelled generating stations, and costs to support an increase in nuclear technical services revenue | (46) | (134) |
| Additional costs included in operations, maintenance and administration expenses related to past grievances by First Nations | - | (39) |
| Increase in earnings on nuclear fixed assets removal and nuclear waste management funds | 10 | 118 |
| Decrease in depreciation expense primarily due to the extension of service lives of the coal-fired generating stations during the third quarter of 2006 | - | 61 |
| Decrease in net interest expense primarily due to deferral of interest related to the Pickering A return to service deferral account | 10 | 43 |
| Increase in amortization of the Pickering A return to service deferral account balance | (14) | (55) |
| Other changes | 1 | (30) |
| **Income before income taxes for the periods ended September 30, 2007** | **139** | **521** |

*Earnings for the Three Months Ended September 30, 2007*

Earnings for the three months ended September 30, 2007 were unfavourably impacted by a decrease in gross margin from electricity sales compared to the same period in 2006. The decrease in gross margin was primarily due to lower generation from OPG's nuclear generating stations, partly offset by increased generation from OPG's unregulated hydroelectric generating facilities and from higher marginal cost fossil-fuelled generating stations. Gross margin was favourably impacted by higher non-electricity generation revenue primarily related to revenue from nuclear technical services.

Operations, maintenance and administration ("OM&A") expenses for the three months ended September 30, 2007 were $689 million compared to $628 million during the same period in 2006. The increase was primarily due to higher maintenance expenditures at OPG's nuclear generating stations and increased maintenance programs and projects related to the extended period over which the coal-fired generating stations will be required to operate. OPG also incurred additional expenses during the third quarter of 2007 related to an increase in nuclear technical services provided to external parties.

Earnings from the nuclear fixed asset removal and nuclear waste management funds ("Nuclear Funds") for the three months ended September 30, 2007 were $92 million compared to $82 million during the same period in 2006. The increase in earnings of $10 million was primarily due to a higher investment base in the Nuclear Funds in the third quarter of 2007 compared to the same period in 2006.

The net interest expense for the three months ended September 30, 2007 was $37 million compared to $47 million for the same period in 2006. The decrease in net interest expense for the three months ended September 30, 2007 was primarily due to the deferral of interest expense related to the Pickering A return to service deferral account as required by the amended regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario).

The amortization of the Pickering A return to service deferral account increased by $14 million for the three months ended September 30, 2007 when compared to the same period in 2006, consistent with the method of recovery of costs included in regulated prices.

*Earnings for the Nine Months Ended September 30, 2007*

Earnings for the nine months ended September 30, 2007 were unfavourably impacted by a decrease in gross margin from electricity sales compared to the same period in 2006 primarily due to lower generation from OPG's nuclear and unregulated hydroelectric generating stations, partly offset by increased generation from higher marginal cost fossil-fuelled generating stations. The gross margin from electricity sales was further reduced by higher coal costs during the nine month period in 2007 compared to the same period in 2006. Other changes in gross margin included an increase in non-electricity revenue primarily due to higher nuclear technical service activities, partially offset by a decrease in trading revenue related to lower mark-to-market gains and lower margins on trading transactions.

Although OPG's gross margin was reduced as a result of replacing lower marginal cost nuclear generation and unregulated hydroelectric generation with higher marginal cost generation from the fossil-fuelled generating stations, this did not result in a material increase in rates charged to consumers.

OM&A expenses for the nine months ended September 30, 2007 were $2,159 million compared to $1,946 million during the same period in 2006. The increase was primarily due to higher maintenance expenditures at OPG's nuclear generating stations, increased maintenance programs and projects related to the extended period over which the coal-fired generating stations will be required to operate, and additional expenses incurred during the second quarter of 2007 related to past grievances by First Nations. OPG also incurred additional expenses during 2007 due to an increase in costs associated with nuclear technical services provided to external parties.

Earnings from the Nuclear Funds for the nine months ended September 30, 2007 were $392 million compared to $274 million during the same period in 2006, an increase of $118 million. The increase in earnings from the Nuclear Funds was due to a higher Ontario Consumer Price Index ("CPI") in 2007 compared to 2006, which impacted the guaranteed return on the Used Fuel Fund, and the reimbursement from the Nuclear Funds for expenditures related to the safe storage of Pickering A Units 2 and 3.

Earnings were favourably impacted by a decrease in depreciation expense of $61 million. The decrease in depreciation expense was primarily due to the extension of the service lives of the coal-fired generating stations for accounting purposes during the third quarter of 2006.

The net interest expense for the nine months ended September 30, 2007 was $102 million compared to $145 million for the same period in 2006. The decrease in net interest expense for the nine months ended September 30, 2007 was primarily due to the deferral of interest expense related to the

Pickering A return to service deferral account as required by the amended regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario).

The amortization of the Pickering A return to service deferral account increased by $55 million for the nine months ended September 30, 2007 when compared to the same period in 2006, consistent with the method of recovery of costs included in regulated prices.

Since April 1, 2005, upon the introduction of rate regulation, OPG has accounted for income taxes related to the rate regulated segments of its business using the taxes payable method. Under this method, future income tax assets and liabilities associated with these segments are not recognized where those future income taxes are expected to be recovered or refunded through future regulated prices charged to customers. As a result, OPG did not record a future tax expense of $20 million and $24 million for the rate regulated segments during the three months ended September 30, 2007 and September 30, 2006, respectively, which would have been recorded had OPG accounted for income taxes for the regulated segments using the liability method. Similarly, for the nine months ended September 30, 2007 and 2006, OPG did not record a future tax expense of $61 million and $42 million, respectively, for the rate regulated segments, 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 and nine months ended September 30 were as follows:

| | **Three Months Ended September 30** | | **Nine Months Ended September 30** | |
|---|---|---|---|---|
| *(¢/kWh)* | **2007** | **2006** | **2007** | **2006** |
| Weighted average hourly Ontario spot electricity market price | **5.1** | 4.9 | **5.0** | 5.0 |
| Regulated – Nuclear | **4.9** | 4.9 | **4.9** | 4.9 |
| Regulated – Hydroelectric[1] | **3.5** | 3.6 | **3.5** | 3.5 |
| Unregulated – Hydroelectric[2] | **4.7** | 4.6 | **4.7** | 4.7 |
| Unregulated – Fossil-Fuelled[2] | **4.9** | 4.8 | **4.9** | 4.8 |
| OPG's average sales price | **4.7** | 4.7 | **4.6** | 4.6 |

[1] 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] 85 per cent of the electricity generated from unregulated stations, excluding the Lennox generating station and other contract volumes, is subject to a revenue limit. During the period from April 1, 2005 to April 30, 2006, the revenue limit was set at 4.7¢/kWh. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh and subsequently increased to 4.7¢/kWh effective May 1, 2007.

The weighted average hourly Ontario spot electricity market price was marginally higher for the three months ended September 30, 2007 compared to the same quarter in 2006 primarily as a result of lower nuclear generation, partially offset by the impact of lower primary demand in Ontario and a stronger Canadian dollar, which contributes to lower spot market prices. OPG's average sales price for the three months ended September 30, 2007 and September 30, 2006 remained unchanged at 4.7¢/kWh. The favourable impact of a higher revenue limit of 4.7¢/kWh for OPG's unregulated electricity generation, which became effective May 1, 2007, was offset by lower average sales prices from Regulated – Hydroelectric generation over 1,900 MWh in any hour during the third quarter of 2007 compared to the same period in 2006.

For the nine months ended September 30, 2007 and September 30, 2006, OPG's average sales price was unchanged at 4.6¢/kWh, which reflected comparable hourly Ontario spot electricity market prices during the respective periods. The favourable impact on OPG's average sales price of a higher revenue limit of 4.7¢/kWh for OPG's unregulated electricity generation, which commenced May 1, 2007, was offset by a lower revenue limit of 4.6¢/kWh during the period January 2007 to April 2007. On May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh.

As a result of regulated prices and the revenue limit rebate, OPG's average sales price was lower than the weighted average hourly Ontario spot electricity market price for the three and nine month periods ended September 30, 2007 and September 30, 2006.

**Electricity Generation**

Total electricity generated during the three months ended September 30, 2007 from OPG's generating stations was 26.2 TWh compared to 27.0 TWh during the same period in 2006. The decrease of 0.8 TWh for the three months ended September 30, 2007 compared to the same period in 2006 was primarily due to lower generation from OPG's nuclear generating stations, partly offset by higher electricity generation from the unregulated hydroelectric and fossil-fuelled generating stations.

Nuclear generation during the three months ended September 30, 2007 decreased compared to the same period last year by 2.1 TWh. The decrease in generation during the third quarter of 2007 compared to the same quarter in 2006 was primarily due to the shutdown of the Pickering A nuclear generating station Units 1 and 4 in early June 2007 to perform modifications on a backup electrical system. These modifications were completed in September 2007. Unit 4 of the Pickering A nuclear generating station was restarted in October 2007, and Unit 1 entered a planned outage.

Electricity generation from the unregulated hydroelectric and fossil-fuelled generating stations during the three months ended September 30, 2007 increased compared to the same period in 2006 by 0.6 TWh and 0.9 TWh, respectively. The higher generation from the unregulated hydroelectric generating stations was primarily due to favourable water conditions during the third quarter of 2007 compared to the same quarter in 2006. The generation from the fossil-fuelled generating stations increased during the three months ended September 30, 2007 compared to the same period in 2006 primarily due to lower generation from the nuclear generating stations and improved station performance, partially offset by lower Ontario primary electricity demand.

For the nine months ended September 30, 2007, electricity generated from OPG's generating stations was 80.4 TWh compared to 80.9 TWh during the same period in 2006. The decrease of 0.5 TWh for the nine months ended September 30, 2007 was primarily due to lower generation from OPG's nuclear generating stations, mostly offset by higher electricity generation from the fossil-fuelled generating stations.

In addition to the shutdown of Pickering A Units 1 and 4 for modifications to the backup electrical system, nuclear generation decreased during the nine months ended September 30, 2007 compared to the same period in 2006 as a result of an unplanned outage during the first quarter of 2007 at the Pickering B nuclear generation station caused by an inadvertent release of resin by a third party contractor from the water treatment plant into the demineralized water system, and the requirement for maintenance related to the recovery of the resin. Nuclear generation in 2007 was also impacted by an extension to a planned outage during the first quarter of 2007 at the Pickering A nuclear generating station for significant additional repair work required as a result of a component failure during inspection.

Electricity generation from the fossil-fuelled generating stations during the nine months ended September 30, 2007 increased by 3.0 TWh compared to the same period in 2006. The increase was primarily due to lower generation from OPG's nuclear generating stations, and improved station performance.

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

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2007** | **2006** | **2007** | **2006** |
| Cooling Degree Days [1] | | | | |
| Period | **306** | 290 | **433** | 390 |
| Ten-year average | **294** | 280 | **389** | 370 |
| Heating Degree Days [2] | | | | |
| Period | **42** | 83 | **2,462** | 2,188 |
| Ten-year average | **57** | 64 | **2,377** | 2,392 |

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

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

Cooling Degree Days for the three and nine month periods ended September 30, 2007 increased compared to the same periods in 2006 as a result of warmer weather in June, August and September 2007. Heating Degree Days for the nine months ended September 30, 2007 increased significantly compared to the same period in 2006 primarily due to weather that was colder than average during the first quarter of 2007 and much warmer than average during the first quarter of 2006. Ontario primary electricity demand was 38.2 TWh for the three months ended September 30, 2007 and 114.5 TWh for the nine months ended September 30, 2007 compared to 38.7 TWh and 114.0 TWh for the same periods of 2006, respectively.

**Cash Flow from Operations**

Cash flow provided by operating activities for the three months ended September 30, 2007 was $248 million compared to cash flow provided by operating activities of $307 million during the same period in 2006. The decrease in cash flow was primarily due to higher operating and maintenance expenditures, a higher revenue limit rebate payment, and lower cash receipts from electricity sales, partially offset by the increase in non-electricity generation revenue.

Cash flow provided by operating activities for the nine months ended September 30, 2007 was $723 million compared to cash flow provided by operating activities of $306 million during the same period in 2006. The increase in cash flow was primarily due to lower revenue limit rebate payments, a higher reimbursement of expenditures for nuclear fixed asset removal and nuclear waste management, and lower payments for fossil fuel during the first nine months of 2007 compared to the same period in 2006. The increase in cash flow was partially offset by a decrease in cash receipts from electricity sales and higher operating and maintenance expenditures. The lower revenue limit rebate payments for the nine months ended September 30, 2007 compared to the same period in 2006 was a result of making a payment of $739 million in the second quarter of 2006 related to the period April 1, 2005 to December 31, 2005. Revenue limit rebate payments are now made on a quarterly basis.

**Recent Developments**

*Exposure to Asset-Backed Commercial Paper Market*

In August 2007, a number of Canadian third-party Trusts, as issuers of ABCP experienced difficulty in accessing the liquidity required to repay maturing ABCP debt. OPG's exposure to third-party ABCP, for notes which had matured and payment had not been received, was $103 million as of September 30, 2007.

Of the $103 million of third-party ABCP held by OPG, $45 million consisted of notes held within Skeena Capital Trust ("Skeena"). In October 2007, investors holding notes of Skeena were notified that they would receive the full value of their investment as a result of a restructuring plan, plus a portion of the accrued interest. Funding for the restructuring will be provided through the issuance of long-term floating rate notes, issued by a new Trust for this purpose to new investors. OPG elected not to purchase the floating rate notes of the new trust, and therefore, expects to receive full value of the notes currently held in Skeena. The proposed restructuring, including the redemption of the notes, is subject to final documentation. Investors were advised that the transaction would be completed by, or shortly after, the end of October 2007. OPG expects that final documentation and settlement is forthcoming. Upon payment of the Skeena notes of $45 million, OPG's holdings of third-party ABCP will be reduced to $58 million held in four different trusts.

OPG has classified the third-party ABCP as temporary investments. The fair value of the assets underlying third-party ABCP and the outcome of any restructuring proposal could give rise to a charge to OPG's earnings. OPG has not recorded any write-down related to its third-party ABCP temporary investments in the third quarter of 2007 based on the expected immateriality of any such charge or write-down, the measurement uncertainty related to this matter, and the expectation that additional information will be available by mid-December, the target date established by the Investors Committee for completing a review of the affected Trusts and providing guidance to noteholders on the proposed restructuring. OPG has sufficient credit facilities to satisfy its financial obligations as they come due and does not expect there will be a material adverse impact on its business as a result of this current third-party ABCP liquidity issue. Further information is disclosed in Note 3 of the interim consolidated financial statements for the three and nine months ended September 30, 2007.

*Climate Change Plan*

In June, 2007, aggressive targets to reduce greenhouse gas emissions were introduced by the Province as part of the Province's climate change plan. Among other initiatives, the plan identified a target reduction of greenhouse gases to six per cent below 1990 levels by 2014. In August 2007, the Province finalized a regulation that commits to end the use of coal to generate electricity at OPG's coal-fired generating stations by December 31, 2014.

The Federal Government, in April 2007, also announced targets for reducing both greenhouse gases and air pollutants from 2006 levels. Under the Federal proposal, OPG would be required to reduce its intensity levels of greenhouse gas emissions from 2006 levels by 18 per cent before 2010, with an eventual reduction of 26 per cent by 2015. The Federal Government has delayed the regulation of air pollutants until the spring of 2008, but hopes to have the greenhouse gas framework finalized by the end of 2007.

*Lennox Generating Station*

The Lennox generating station operated under a reliability must-run ("RMR") contract approved by the OEB for the period beginning on October 1, 2006 to September 30, 2007. The IESO has concluded that all four units at the Lennox generating station continue to be required for the purpose of reliability, and has recommended that all four units be covered by an RMR contract for the period October 2007 to September 2008. An RMR contract with the IESO for the period October 1, 2007 to September 30, 2008 has been finalized, and has been submitted to the OEB for approval.

## 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. To achieve its mandate, OPG is focused on four corporate strategies: improving the performance of its generating assets; increasing its generating capacity; achieving financial sustainability; and achieving excellence in corporate governance, safety, social responsibility, corporate citizenship and environmental stewardship. A detailed discussion of these strategies is outlined in the 2006 annual MD&A under the heading, *Vision, Core Business and Strategy*.

**Improving the Performance of Generating Assets**

*Nuclear Generating Assets*

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

During the third quarter of 2007, the Darlington nuclear generating station continued its strong operating performance. Electricity generation from the Pickering A nuclear generating station was significantly reduced in the third quarter of 2007 due to the required outage to modify a backup electrical system. Operating performance at the Pickering B nuclear generating station decreased during the three months ended September 2007 due to equipment failure and adverse algae conditions in Lake Ontario that affected certain water intake systems. OPG's safety and environmental results continue to be strong at all nuclear generating stations.

In the third quarter of 2007, the Canadian Nuclear Safety Commission ("CNSC") concluded that an Environmental Assessment ("EA") was necessary for certain parts of the Units 2 and 3 safe storage project at the Pickering A nuclear generating station. As a result, certain planned work has been suspended, pending initiation and completion of the EA. The EA may delay the safe storage project by about a year and may increase the total decommissioning cost by approximately $20 million.

Work is proceeding on the feasibility study of the Pickering B nuclear generating station refurbishment project. This work includes a plant condition assessment, an EA, and an Integrated Safety Review. OPG plans to make a recommendation on the feasibility of this project to its Board of Directors. Work concerning the potential refurbishment of the Darlington nuclear generating station will start in 2008.

*Hydroelectric Generating Assets*

OPG's strategic objective is improving production from its existing hydroelectric generating assets in a cost effective and efficient manner. Prudent investments will be undertaken to maintain and/or improve the condition, reliability and efficiency of the hydroelectric generating assets. Programs and initiatives are underway to increase the availability of existing stations by replacing aging and obsolete equipment, upgrading turbine runners with more efficient equipment, and ensuring that maintenance is performed in a timely and cost effective manner. These performance improvement initiatives are being pursued while maintaining OPG's focus on employee and public safety, dam safety, environmental stewardship, and community relations.

OPG's hydroelectric generating assets continued to achieve a high availability of 94.2 per cent, thus maximizing production from available water flows. Initiatives to increase the capacity at OPG's existing hydroelectric generating stations continued with rehabilitations and upgrades of equipment at six stations. Rehabilitation of single generating units started at each of the following generating stations: Caribou Falls, Des Joachims, Otto Holden, Chats Falls and Sir Adam Beck 1. The Sir Adam Beck Unit 7 rehabilitation involves the conversion of a 25 Hertz unit to 60 Hertz, and will add about 62 MW of capacity. During the third quarter of 2007, rehabilitation at one of the generating units at the Abitibi Canyon generating station was completed, adding 10 MW of capacity.

The safety performance of the hydroelectric generating assets continues to be strong with no lost time accidents in 2007. Hydroelectric operations achieved a major milestone of two years without a lost time accident to the end of the third quarter of 2007.

*Fossil-Fuelled Generating Assets*

OPG will maintain the productive capability of its coal-fired generating facilities, while continuing to operate in compliance with all applicable environmental laws and emission regulations. Maintenance programs have been implemented to mitigate the impacts of increased unit starts and stops on the equipment, which results from the role the fossil-fuelled generating stations perform as intermediate and peaking facilities.

In 2007, production from OPG's fossil-fuelled stations increased compared to the same period in 2006. Reliability, as measured by equivalent forced outage rates significantly improved during the nine months ended September 30, 2007, compared to performance during the nine months ended September 30, 2006. Emissions performance was well within regulatory limits. A focus on maintenance, environmental and recruitment programs will enable the continued operation of the coal-fired generating stations until their planned shut-down.

**Increasing OPG's Generating Capacity**

OPG's strategy with respect to increasing its generating capacity is to expand, develop, and/or improve its hydroelectric generating capacity by expanding and redeveloping its existing sites, as well as pursuing new projects where feasible. In addition, OPG, in consultation with its shareholder, plans to increase its generating capacity by exploring and developing, where feasible, natural gas and nuclear opportunities in Ontario. OPG will undertake these investments on its own or through partnerships. OPG is currently involved in the following hydroelectric, natural gas and nuclear generation projects.

*Niagara Tunnel*

The Niagara tunnel project will increase the amount of water flowing to existing turbines at OPG's Sir Adam Beck generating stations in Niagara Falls, allowing the stations to utilize available water more effectively. Upon the completion of the 10.4 km tunnel, the average annual generation from the Sir Adam Beck generating stations is expected to increase by approximately 1.6 TWh.

At September 30, 2007, the tunnel boring machine had advanced 1,028 metres. The progress of the tunnel boring machine by the design-build contractor through a fractured rock formation has been slower than expected. As a result, the contractor's forecast completion date has been delayed from late 2009. Considerable uncertainty remains with respect to the schedule until the tunnel boring machine advances sufficiently beyond the St. David's Gorge to approximately 2,300 metres and establishes consistent tunneling performance. Potential deviation from the original project completion schedule approved by OPG's Board of Directors of June 2010 will be assessed at that point.

The contract structure puts the onus on the contractor to mitigate schedule delays, including liquidated damages provisions for failure to meet the contractual in-service date. The project is still expected to be completed within the budgeted cost estimate of $985 million.

The capital project expenditures for the three months ended September 30, 2007 were $10 million and life-to-date capital expenditures were $281 million. The project is debt financed through the Ontario Electricity Financial Corporation ("OEFC").

*Lac Seul*

OPG is constructing 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. In accordance with the contractor's original schedule, the project was expected to be in-service in the fourth quarter of 2007. However, the contractor has advised OPG that the project is now expected to be in-service in the second quarter of 2008. The project delays are a result of various difficulties, including the replacement of the major subcontractor. Total project costs are still expected to be $47 million.

The design-build contract includes liquidated damages terms to mitigate against, among other things, any late in-service date on the project. OPG will deduct applicable liquidated damages from amounts otherwise payable to the contractor for the late in-service date.

During the three months ended September 30, 2007, the tailrace gates were installed and tested. Work continued on the intake structure and in pouring concrete around embedded turbine and generator parts. Capital project expenditures for the three months ended September 30, 2007 were approximately $4 million and life-to-date capital expenditures were approximately $38 million. The project is debt financed through the OEFC. OPG is continuing negotiations with the OPA for a contract for electricity produced from the new facility and the existing Ear Falls generating station.

*Lower Mattagami*

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

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

OPG is continuing its consultations with First Nation stakeholders regarding an agreement to address past issues and establish a new commercial relationship.

After consultation with the Canadian Environmental Assessment Agency ("CEAA"), it has been determined that a comprehensive study process must be followed under CEAA regulations. The scoping document for this process has been posted on the CEAA website for public comment.

*Small Hydroelectric Projects*

OPG is currently pursuing the redevelopment of four existing end-of-life hydroelectric generation stations, consisting of three stations on the Upper Mattagami River (Wawaitin, Sandy Falls and Lower Sturgeon) and the Hound Chute generating station on the Montreal River. In addition, OPG is pursuing an expansion of the existing Healey Falls generating station on the Trent-Severn Waterway (collectively, the "Small Hydroelectric Projects"). The installed capacity will increase from 23 MW to 50 MW and the average annual energy generated will increase from 134 gigawatt hours ("GWh") per year to 248 GWh per year. These projects are subject to approval by OPG's Board of Directors.

*Portlands Energy Centre*

OPG entered into a partnership with TransCanada Energy Ltd. ("TransCanada"), through the 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. OPG has a 50 per cent ownership interest in the joint venture.

Construction of PEC started in 2006 and is expected to be operational in a simple cycle mode with a capacity of up to 340 MW by June 1, 2008. The simple cycle mode will only operate as needed during the summer of 2008, after which it will be taken out of service to enable construction to be completed on the combined cycle mode. During the third quarter of 2007, construction progress included substantial work on the pumphouse, assembly of generator step-up transformers, erection of gas compressor building steel, and completion of the steam turbine generator pedestal.

The plant is expected to be completed and fully operational in the second quarter of 2009, providing up to 550 MW of power in a combined cycle mode. Project costs are expected to be within the approved budget of $730 million excluding capitalized interest. A significant proportion of this capital cost relates to an engineer-procure-construct ("EPC") contract to construct the facility.

OPG's share of capital expenditures for the three months ended September 30, 2007 was $47 million. OPG's share of the life-to-date capital expenditures was $244 million. OPG's share of the project is debt financed through the OEFC.

*Lakeview Site*

OPG is continuing with the decommissioning and demolition of the Lakeview coal-fired generating station, having closed the station in 2005 after more than 40 years of service. Subsequent to the closure, the stacks were taken down, the turbine hall has been demolished, and the remainder of the powerhouse was imploded. OPG is exploring the potential development of a gas-fired electricity generating station at the site. Construction of a new plant would proceed only after the required approvals and the completion of a clean energy supply agreement.

*New Nuclear Generating Units*

As directed by the Minister of Energy in June 2006, OPG initiated a federal approvals process with the CNSC in September 2006 by filing with the CNSC an Application for a Site Preparation Licence for new nuclear generating units at OPG's Darlington nuclear generating site.

During the first quarter of 2007, OPG proceeded with initiatives in support of an environmental assessment for new nuclear units at Darlington including geology, hydrogeology, archeology and terrestrial studies. During the second quarter of 2007, OPG continued to the second step in the federal approvals process by filing a Project Description that will be used by the CNSC to determine the type of EA that is required. Planning for new nuclear generating units at OPG's Darlington nuclear generating site continued in the third quarter of 2007.

OPG and Bruce Power are jointly undertaking an assessment of the potential nuclear technologies which might be deployed in Ontario. Technologies under review include existing, evolutionary and new designs. This assessment will provide the Province with a generator's perspective to be considered in its global scan of reactor technologies.

**Achieving Financial Sustainability**

OPG's financial priority, as a commercial enterprise, is to operate on a financially sustainable basis by optimizing the utilization of available resources, maximizing funds from operations, implementing effective cost management initiatives, and maintaining the value of its assets for its shareholder.

OPG reached an agreement with its bank lending group to renew its $1 billion bank credit facility with a commitment to extend the term of the $500 million tranche from three to five years, and maintain the $500 million 364-day tranche. OPG also reached an agreement with the OEFC for a $500 million general corporate facility that is available for the period June 1, 2007 to March 31, 2008, and for a $950 million credit agreement to refinance senior notes as they mature over the period September 2007 to September 2009. These facilities serve to ensure that adequate financing resources are available beyond OPG's $1 billion bank credit facility and will allow OPG to fix the term of notes issued for periods of up to ten years under these facilities, thereby extending the Company's overall debt profile.

## ONTARIO ELECTRICITY MARKET TRENDS

In its 18-Month Outlook published in September 2007, the IESO indicated that Ontario's existing installed electricity generating capacity was 31,214 MW. OPG's in-service electricity generating capacity at the end of the third quarter of 2007 was 22,157 MW or 71 per cent of Ontario's capacity. The expected peak electricity demand in the winter of 2007-2008, under normal weather conditions, is forecast to be 24,739 MW. Peak demand in the summer of 2008 is forecast to be 26,041 MW. Energy demand in 2007 is now forecast to be 152.7 TWh, which is slightly lower than the IESO's June 2007 forecast of 153.7 TWh. This primarily results from the impact of planned conservation measures and lower industrial demand. The IESO reported that over the next 18 months, the outlook for Ontario's supply/demand balance remains generally positive under a normal weather scenario. Over the next 18 months, more than 2,900 MW of new supply is scheduled. The new supply scheduled includes more than 2,000 MW of gas-fired generation, and over 700 MW of wind generation. This represents the highest amount of additional capacity in an 18-Month Outlook period since the Ontario electricity market began.

Fuel prices which are affected by the underlying commodity price and the United States dollar ("USD") to Canadian dollar exchange rate, can have a significant impact on revenue and gross margin. Uranium spot market prices have increased significantly since the beginning of 2003 and have displayed significant volatility in 2007. The increase in the price of uranium is the result of many supply and demand factors that may persist and continue to support higher prices for a number of years. Any significant impact on OPG's fuel costs has been delayed as the Company draws down on inventories purchased at lower prices. However, fuel costs for nuclear operations are expected to be significantly higher in the near future. During the third quarter of 2007, market prices for natural gas and coal increased marginally over the market prices in the same period of 2006. The outlook for gas prices remains volatile, although the longer term trend is firming in the futures markets. Coal prices are expected to stabilize in the current trading range. With the Federal Government's proposed EcoAction regulations, emission credit costs associated with the use of fossil fuels in the electricity sector could increase after 2009.

In August 2007, the OPA filed its proposed 20-year energy plan for Ontario, the Integrated Power System Plan ("IPSP"), with the OEB for approval. Under Ontario Regulation 424/04 (the "IPSP Regulation"), the OPA is required to develop and submit an IPSP that covers a period of 20 years from the date of its submission and to develop and submit an updated 20-year plan every three years thereafter. The OEB will review the IPSP and assess whether it is consistent with government directives, complies with the IPSP Regulation, and is prudent and cost effective. The plan's estimated $60 billion capital cost would be directed toward conservation initiatives, new renewable generation including hydroelectric facilities, refurbishment or replacement of nuclear generation for baseload capacity, natural gas-fired generation for intermediate and peaking uses, and the transmission capacity required to deliver the electricity to Ontario consumers. The plan also calls for the phase-out of coal-fired electricity generation by the end of 2014.

## BUSINESS SEGMENTS

OPG has four reportable business segments. The business segments are Regulated – Nuclear, Regulated – Hydroelectric, Unregulated – Hydroelectric, and Unregulated – Fossil-Fuelled.

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 in the Unregulated – Hydroelectric and Unregulated – Fossil-Fuelled generation segments. Gains or losses from 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 most of the Company's baseload hydroelectric generating stations. The business segment is comprised of electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls

1 and 2, and the R.H. Saunders hydroelectric facilities. The Regulated – Hydroelectric business segment also includes ancillary revenues related to these stations earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control.

### Unregulated – Hydroelectric Segment

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its hydroelectric generating stations that are not subject to rate regulation. The Unregulated – Hydroelectric business segment also includes ancillary revenues earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control, and revenues from other services.

### Unregulated – Fossil-Fuelled Segment

The Unregulated – Fossil-Fuelled business segment operates in Ontario, generating and selling electricity from its fossil-fuelled generating stations, which are not subject to rate regulation. The Unregulated – Fossil-Fuelled business segment also includes ancillary revenues earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control/reactive support and automatic generation control, and revenues from other services.

### Other

The Other category includes revenue that OPG earns from its 50 per cent 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 affected by planned and unplanned outages. Capability factors by industry definition exclude grid-related unavailability.

### 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 generating stations is the proportion of time they are available to produce electricity when required. 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 storage and the disposal of low and intermediate level radioactive waste materials, divided by nuclear electricity generation.

### 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 annualized OM&A expenses for the period, including allocated corporate costs, divided by total station nameplate capacity.

### Other Key Indicators

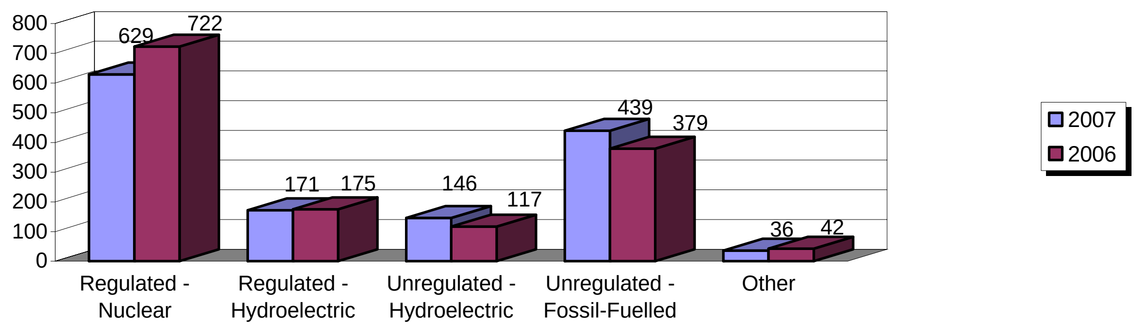
In addition to performance and cost effectiveness indicators, OPG has identified certain environmental indicators. These indicators are discussed under the heading, *Risk Management*.

**DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT**

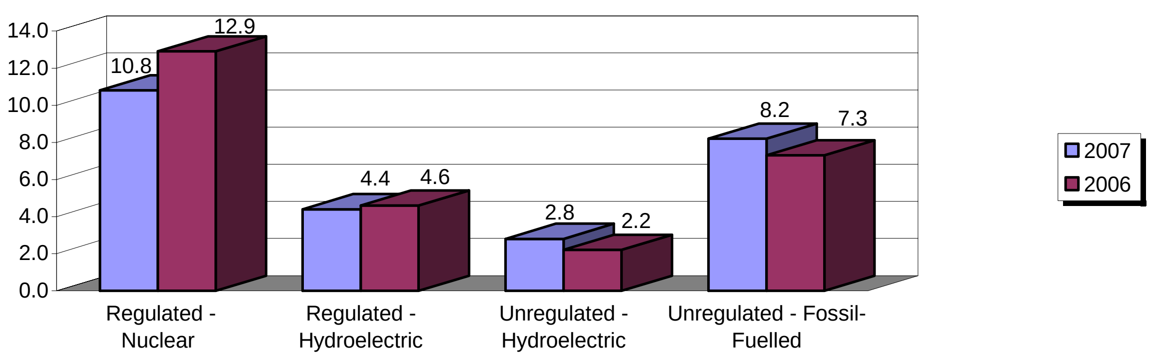
This section summarizes OPG's key results by segment for the three and nine months ended September 30, 2007 and 2006. The following table provides a summary of revenue, earnings and key generation and financial performance indicators by business segment:

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *(millions of dollars)* | **2007** | **2006** | **2007** | **2006** |
| *Revenue, net of revenue limit rebate* | | | | |
| Regulated – Nuclear | **629** | 722 | **1,943** | 2,067 |
| Regulated – Hydroelectric | **171** | 175 | **526** | 514 |
| Unregulated – Hydroelectric | **146** | 117 | **533** | 545 |
| Unregulated – Fossil-Fuelled | **439** | 379 | **1,213** | 1,044 |
| Other | **36** | 42 | **103** | 118 |
| | **1,421** | 1,435 | **4,318** | 4,288 |
| *(Loss) income before interest and income taxes* | | | | |
| Regulated – Nuclear | **(30)** | 101 | **24** | 193 |
| Regulated – Hydroelectric | **69** | 65 | **190** | 207 |
| Unregulated – Hydroelectric | **65** | 34 | **271** | 297 |
| Unregulated – Fossil-Fuelled | **57** | 39 | **90** | 30 |
| Other | **15** | 26 | **48** | 76 |
| | **176** | 265 | **623** | 803 |
| *Electricity Generation (TWh)* | | | | |
| Regulated – Nuclear | **10.8** | 12.9 | **33.5** | 36.8 |
| Regulated – Hydroelectric | **4.4** | 4.6 | **13.7** | 13.5 |
| Unregulated – Hydroelectric | **2.8** | 2.2 | **10.6** | 11.0 |
| Unregulated – Fossil-Fuelled | **8.2** | 7.3 | **22.6** | 19.6 |
| Total electricity generation | **26.2** | 27.0 | **80.4** | 80.9 |
| *Nuclear unit capability factor (per cent)* | | | | |
| Darlington | **96.3** | 94.5 | **91.4** | 89.8 |
| Pickering A | **-** | 82.9 | **41.5** | 86.1 |
| Pickering B | **82.0** | 87.5 | **74.7** | 79.2 |
| *Equivalent forced outage rate (per cent)* | | | | |
| Regulated – Hydroelectric | **1.1** | 1.1 | **1.1** | 0.9 |
| Unregulated – Hydroelectric | **2.5** | 3.4 | **1.7** | 1.8 |
| Unregulated – Fossil-Fuelled | **10.5** | 11.7 | **11.2** | 12.5 |
| *Availability (per cent)* | | | | |
| Regulated – Hydroelectric | **97.4** | 95.9 | **94.2** | 93.1 |
| Unregulated – Hydroelectric | **92.2** | 89.2 | **94.2** | 92.9 |
| *Nuclear PUEC ($/MWh)* | **45.76** | 35.97 | **45.56** | 39.16 |
| *Regulated – Hydroelectric OM&A expense per MWh ($/MWh)* | **5.23** | 5.65 | **5.11** | 5.19 |
| *Unregulated – Hydroelectric OM&A expense per MWh ($/MWh)* | **15.71** | 21.36 | **12.08** | 11.09 |
| *Unregulated – Fossil-Fuelled OM&A expense per MW ($000/MW)* | **60.7** | 53.6 | **64.4** | 58.3 |

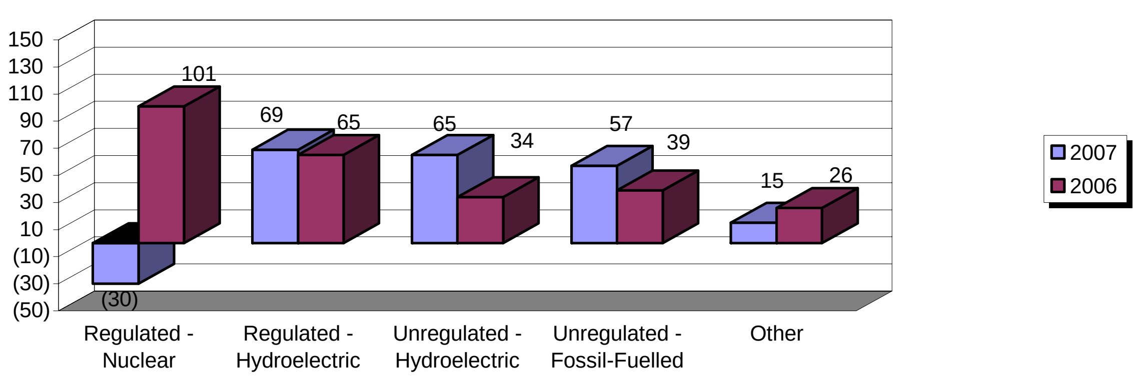
**Revenue, Net of Revenue Limit Rebate by Segment**
**Three Months Ended September 30**
*(millions of dollars)*



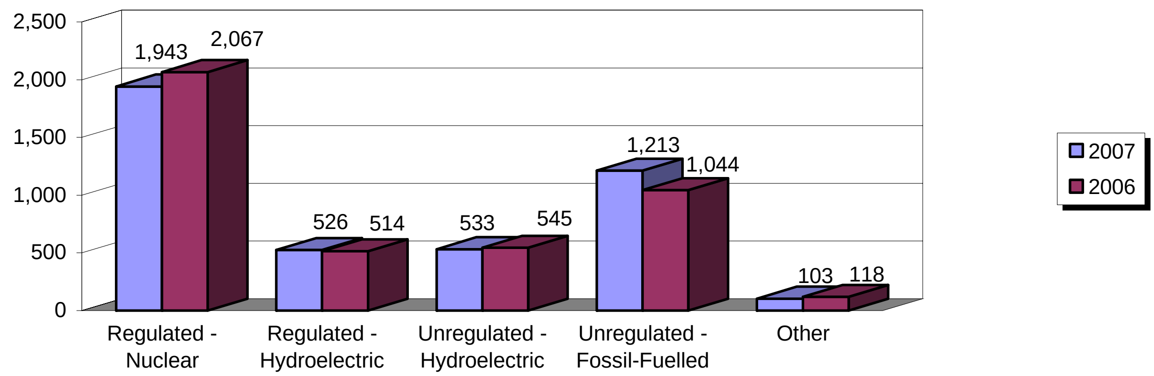

**Electricity Generation by Segment**
**Three Months Ended September 30**
*(TWh)*



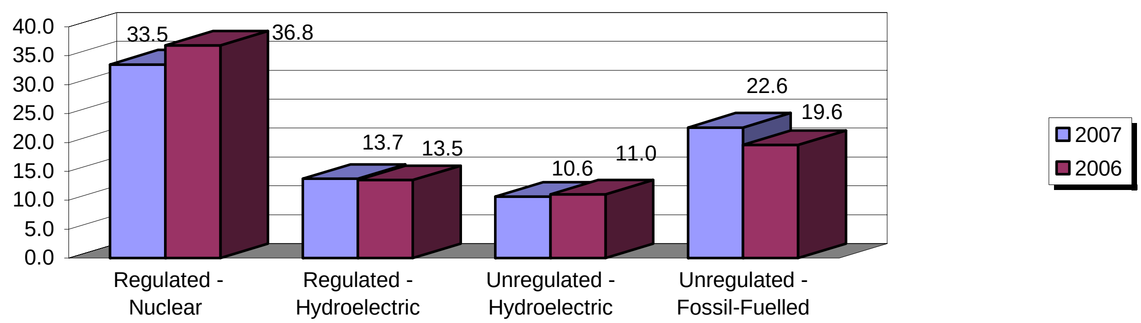

**(Loss) Income Before Interest and Income Taxes by Segment**
**Three Months Ended September 30**
*(millions of dollars)*



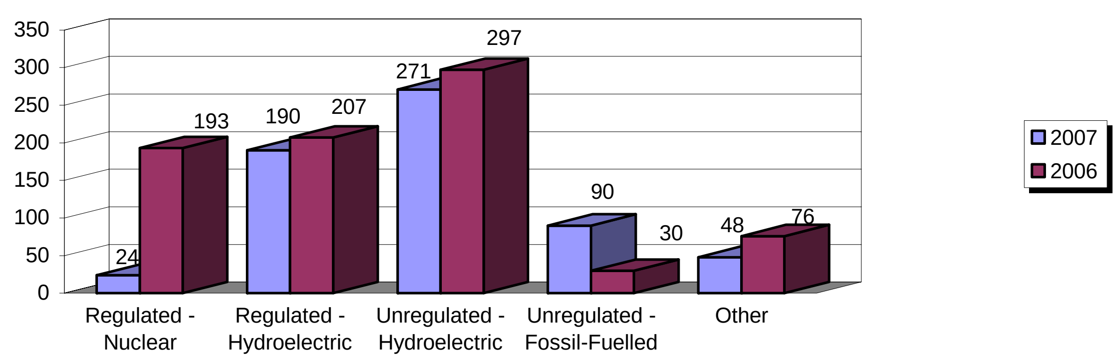
**Revenue, Net of Revenue Limit Rebate by Segment**
**Nine Months Ended September 30**
*(millions of dollars)*




**Electricity Generation by Segment**
**Nine Months Ended September 30**
*(TWh)*




**Income Before Interest and Income Taxes by Segment**
**Nine Months Ended September 30**
*(millions of dollars)*



**Regulated – Nuclear Segment**

| *(millions of dollars)* | Three Months Ended September 30 2007 | 2006 | Nine Months Ended September 30 2007 | 2006 |
|---|---|---|---|---|
| Revenue | **629** | 722 | **1,943** | 2,067 |
| Fuel expense | **33** | 34 | **98** | 93 |
| Gross margin | **596** | 688 | **1,845** | 1,974 |
| Operations, maintenance and administration | **487** | 440 | **1,496** | 1,378 |
| Depreciation and amortization | **104** | 91 | **320** | 275 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **124** | 123 | **374** | 368 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(92)** | (82) | **(392)** | (274) |
| Property and capital taxes | **3** | 15 | **23** | 34 |
| (Loss) income before interest and income taxes | **(30)** | 101 | **24** | 193 |

*Revenue*

| *(millions of dollars)* | Three Months Ended September 30 2007 | 2006 | Nine Months Ended September 30 2007 | 2006 |
|---|---|---|---|---|
| Regulated generation sales | **536** | 638 | **1,650** | 1,813 |
| Other | **93** | 84 | **293** | 254 |
| Total revenue | **629** | 722 | **1,943** | 2,067 |

Regulated – Nuclear revenue was $629 million for the three months ended September 30, 2007 compared to $722 million during the same period in 2006. The decrease in revenue of $93 million was primarily due to lower electricity generation of 2.1 TWh compared to the same period in 2006, partially offset by an increase in non-electricity generation revenue from nuclear technical services.

Regulated – Nuclear revenue was $1,943 million for the nine months ended September 30, 2007 compared to $2,067 million during the same period in 2006. The decrease of $124 million was primarily due to lower electricity generation of 3.3 TWh, partially offset by higher non-electricity generation revenue from nuclear technical services.

*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.

*Volume*

Electricity generation from stations in the Regulated – Nuclear segment for the three months ended September 30, 2007 was 10.8 TWh compared to 12.9 TWh for the same period in 2006. The decrease in electricity generation of 2.1 TWh was primarily due to the shutdown of the Pickering A nuclear generating station Units 1 and 4 in early June 2007 to perform modifications on a backup electrical system. This system provides a redundant electrical connection for the Pickering A generating station from the Pickering B generating station. A strict safety protocol dictated that Units 1 and 4 remain off-line during the completion of the modifications to the backup electrical system. This modification was completed in September 2007. Unit 4 of the Pickering A nuclear generating station was restarted in October 2007, and

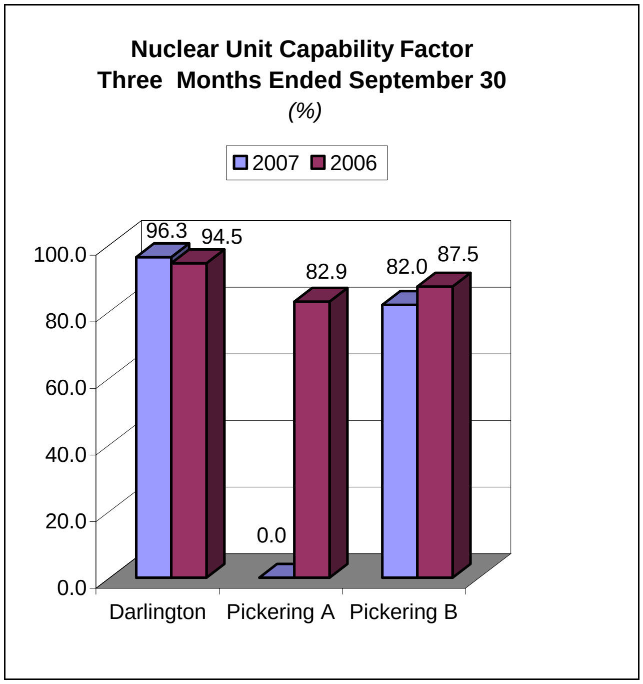
Unit 1 entered a planned outage. In addition, the electricity generation was unfavourably impacted by outages during the third quarter of 2007 at Unit 5 of the Pickering B nuclear generating station and higher planned outage days. The impact of the lower generation from the Pickering A and the Pickering B nuclear generating stations during the third quarter of 2007 was partially offset by continued strong performance at the Darlington nuclear generating station.

Total nuclear generation for the nine months ended September 30, 2007 was 33.5 TWh compared to 36.8 TWh for the same period in 2006. In addition to the factors that affected nuclear generation during the third quarter of 2007, lower nuclear generation during the nine months ended September 30, 2007 was primarily a result of an unplanned outage during the first quarter of 2007 at the Pickering B nuclear generation station caused by an inadvertent release of resin by a third party contractor from the water treatment plant into the demineralized water system, and the requirement for maintenance related to the recovery of the resin. Nuclear generation during the nine months ended September 30, 2007 was also impacted by an extension to a planned outage during the first quarter of 2007 at the Pickering A nuclear generating station for significant additional repair work required as a result of a component failure during inspection.

The Darlington nuclear generating station's unit capability factor for the three months ended September 30, 2007 was 96.3 per cent compared to 94.5 per cent for the same period in 2006, reflecting the continued high reliability of the generating station.

The low unit capability factor for the Pickering A nuclear generating station for the third quarter of 2007 reflected the shutdown of Units 1 and 4 to perform modifications on the backup electrical system.

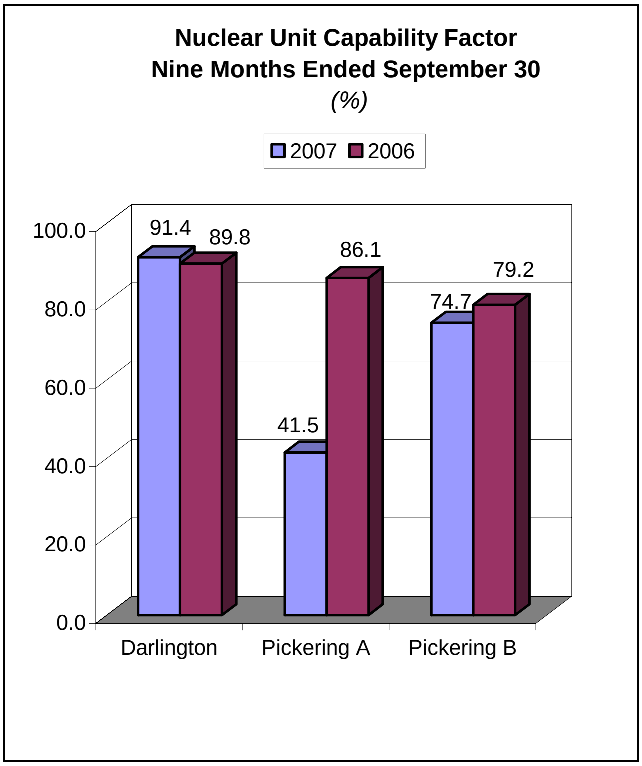
The Pickering B nuclear generating station's unit capability factor was 82.0 per cent for the three months ended September 30, 2007 compared to 87.5 per cent for the same period in 2006. The decrease was primarily due to a higher number of planned and unplanned outage days, and due to adverse algae conditions during the third quarter of 2007.



For the nine months ended September 30, 2007, the unit capability factor for the Darlington nuclear generating station was 91.4 per cent compared to 89.8 per cent for the same period in 2006.

The Pickering A nuclear generating station's unit capability factor was 41.5 per cent for the nine months ended September 30, 2007 compared to 86.1 per cent during the same period in 2006. The decrease was primarily due to significantly higher outage days due to the shutdown of Pickering A nuclear generating station Units 1 and 4 to perform modifications to the backup electrical system and as a result of the component failure during inspection during the first quarter of 2007.

For the nine months ended September 30, 2007, the Pickering B nuclear generating station unit capability factor was 74.7 per cent compared to 79.2 per cent during the same period in 2006. The decrease was primarily due to higher unplanned outage days related to the release of resin into the demineralized water system during the first quarter of 2007 and higher planned and unplanned outage days during the third quarter of 2007.




*Fuel Expense*

Fuel expense for the three months ended September 30, 2007 was $33 million compared to $34 million during the same period in 2006. The decrease in fuel expense for the three months ended September 30, 2007 was primarily due to the decrease in nuclear generation, partially offset by higher uranium prices compared to the same period in 2006.

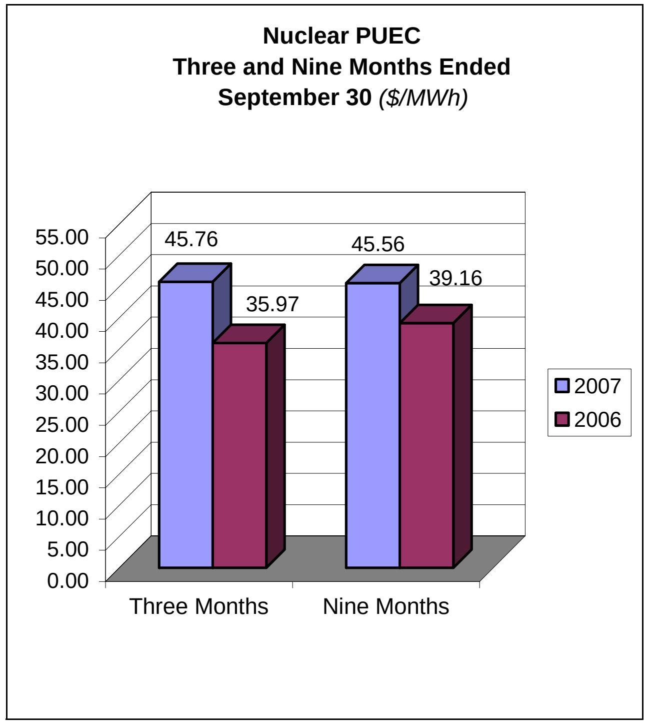
Fuel expense for the nine months ended September 30, 2007 was $98 million compared to $93 million during the same period in 2006. The increase in fuel expense was primarily due to higher uranium prices compared to the same period in 2006, partially offset by the impact of lower generation.

*Operations, Maintenance and Administration*

OM&A expenses for the three months ended September 30, 2007 were $487 million compared to $440 million during the same period in 2006. OM&A expenses were $1,496 million for the nine months ended September 30, 2007 compared to $1,378 million during the same period in 2006. The increase in OM&A expenses was primarily due to higher expenditures for outages and costs related to the increase in nuclear technical services revenue, partially offset by lower project expenditures.

Based on the amendment to the regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) made in February 2007, OPG recorded as a regulatory asset $6 million of non-capital costs for nuclear generation development initiatives during the three months ended September 30, 2007. During the nine months ended September 30, 2007, OPG recorded $20 million as a regulatory asset.

Nuclear PUEC for the three months ended September 30, 2007 was $45.76/MWh compared to $35.97/MWh during the same period in 2006. For the nine months ended September 30, 2007, Nuclear PUEC was $45.56/MWh compared to $39.16/MWh during the same period in 2006. The increase was primarily due to higher outage and other maintenance expenditures and lower generation volume.




*Depreciation and Amortization*

Depreciation and amortization expense for the three months ended September 30, 2007 was $104 million compared to $91 million for the three months ended September 30, 2006. Depreciation and amortization expense was $320 million for the nine months ended September 30, 2007 compared to $275 million for the nine months ended September 30, 2006. The increase in depreciation and amortization expense was primarily due to the amortization of the Pickering A return to service deferral account.

The amortization of the Pickering A return to service deferral account was $20 million for the third quarter of 2007 compared to $6 million during the same period in 2006. For the nine months ended September 30, 2007, the amortization expense was $76 million compared to $21 million for the same period last year. The amortization expense is consistent with the method of recovery of the deferred costs included in regulated prices.

At December 31, 2006, OPG increased the estimate of the present value of the asset retirement obligation for nuclear fixed asset removal and nuclear waste management by $1,386 million, based on an approved reference plan in accordance with the terms of the ONFA (the “2006 Approved Reference Plan”). Asset retirement costs are capitalized by increasing the carrying value of the related fixed assets. As a result, OPG recorded an increase in the carrying value of the nuclear fixed assets of $1,386 million at December 31, 2006. For the three and nine months ended September 30, 2007, OPG recognized additional depreciation expense of $14 million and $42 million, respectively, related to this increase. The increase in depreciation expense was offset by the impact of establishing a deferral account, effective January 1, 2007, related to the change in the liabilities for nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management, as prescribed by the amended regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario).

*Accretion*

Accretion expense was $124 million for the three months ended September 30, 2007 compared to $123 million for the same period in 2006. Accretion expense for the nine months ended September 30, 2007 was $374 million compared to $368 million during 2006. The increase was due to the higher nuclear fixed asset removal and nuclear waste management liability compared to the same periods in 2006 primarily as a result of the increase in the present value of the liability due to the passage of time. For the three and nine months ended September 30, 2007, OPG recorded additional accretion expense related to the increase in the estimate of the liability. This increase in accretion expense was largely offset by the impact of establishing the deferral account effective January 1, 2007 relating to the change in estimate of the liabilities, as prescribed by the amended regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario).

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

Earnings from the Nuclear Funds for the three months ended September 30, 2007 were $92 million compared to $82 million during the same period in 2006. The increase in earnings of $10 million from the Nuclear Funds was primarily due to a higher investment base in the Nuclear Funds.

Earnings from the Nuclear Funds for the nine months ended September 30, 2007 were $392 million compared to $274 million during the same period in 2006, an increase of $118 million. This increase was due in part to higher returns on the Used Fuel Fund as a result of a higher Ontario CPI during the nine months ended September 30, 2007 compared to the same period in 2006. Under the ONFA, the Province guarantees the rate of return in the Used Fuel Fund at 3.25 per cent plus the change in the Ontario CPI. The increase in earnings was also due to a reimbursement from the Decommissioning Fund of safe storage costs for Pickering A Units 2 and 3 of $46 million, which were approved under the ONFA by the Province during the second quarter of 2007.

The Decommissioning Fund is currently overfunded compared to the estimated completion costs for nuclear fixed asset removal and the disposal of low and intermediate level nuclear waste materials as per the most recently approved ONFA reference plan. The value of the investments recorded in the Decommissioning Fund is limited to the cost estimate under the ONFA of the related liability, since the Province has a right to the excess funding in the Decommissioning Fund. The disbursement from the Decommissioning Fund for the safe storage costs during the second quarter of 2007 resulted in a decrease in the amount of the excess funding amount payable to the Province, and a corresponding increase in earnings.

Commencing January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3855, Financial Instruments – Recognition and Measurement. As a result, the investments in the funds and the corresponding payables to the Province are measured at fair value. The impact of the new handbook section is described under the heading *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds* in the *Balance Sheet Highlights* section.

**Regulated – Hydroelectric Segment**

| *(millions of dollars)* | Three Months Ended September 30 **2007** | **2006** | Nine Months Ended September 30 **2007** | **2006** |
|---|---|---|---|---|
| Revenue | **171** | 175 | **526** | 514 |
| Fuel expense | **60** | 62 | **179** | 174 |
| Gross margin | **111** | 113 | **347** | 340 |
| Operations, maintenance and administration | **23** | 26 | **97** | 70 |
| Depreciation and amortization | **16** | 16 | **50** | 49 |
| Property and capital taxes | **3** | 6 | **10** | 14 |
| Income before interest and income taxes | **69** | 65 | **190** | 207 |

*Revenue*

| *(millions of dollars)* | Three Months Ended September 30 **2007** | **2006** | Nine Months Ended September 30 **2007** | **2006** |
|---|---|---|---|---|
| Regulated generation sales[1] | **151** | 165 | **483** | 469 |
| Variance accounts | **9** | 5 | **8** | 1 |
| Other | **11** | 5 | **35** | 44 |
| Total revenue | **171** | 175 | **526** | 514 |

[1] Regulated generation sales included revenue of $37 million that OPG received at the Ontario spot market price for generation over 1,900 MWh in any hour during the three months ended September 30, 2007 (three months ended September 30, 2006 – $54 million). Regulated generation sales included revenue of $127 million that OPG received at the Ontario spot market price for generation over 1,900 MWh in any hour during the nine months ended September 30, 2007 (nine months ended September 30, 2006 – $123 million).

Regulated – Hydroelectric revenue was $171 million for the three months ended September 30, 2007 compared to $175 million during the same period in 2006. The decrease in revenue for the three months ended September 30, 2007 was primarily due to lower electricity generation volume, combined with a lower spot market price for generation in excess of 1,900 MWh in any hour.

Regulated – Hydroelectric revenue was $526 million during the nine months ended September 30, 2007, compared to $514 million during the same period in 2006. The increase in revenue for the nine month period was primarily due to higher electricity generation volume.

*Electricity Prices*

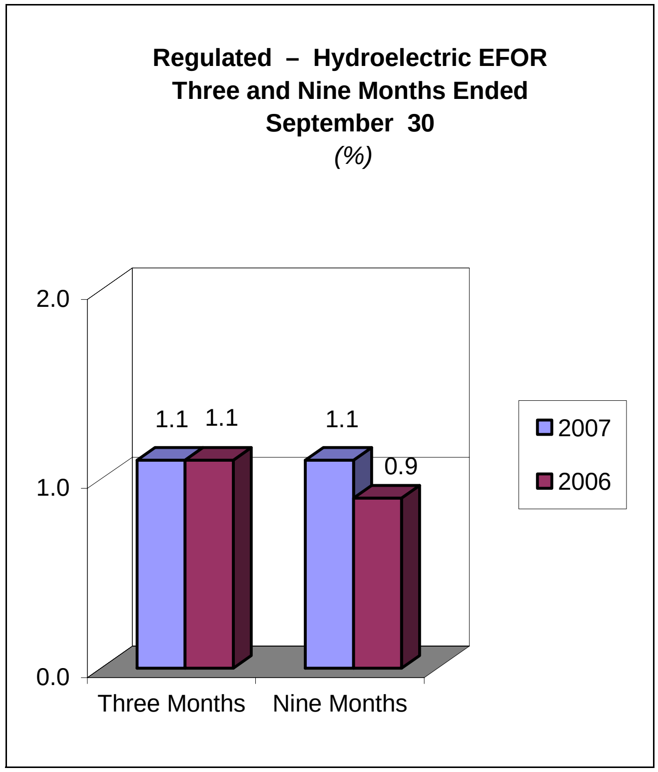
During the three months ended September 30, 2007, the average electricity sales price for the Regulated – Hydroelectric segment was 3.5¢/kWh compared to 3.6¢/kWh during the same period in 2006. The average electricity sales price for the nine months ended September 30, 2007 and 2006 was 3.5¢/kWh. The 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.

*Volume*

Electricity sales volume for the third quarter of 2007 was 4.4 TWh compared to 4.6 TWh during the same period in 2006. The decrease in electricity sales volume in the quarter was due to lower water levels in the Great Lakes and St. Lawrence River during the summer of 2007.

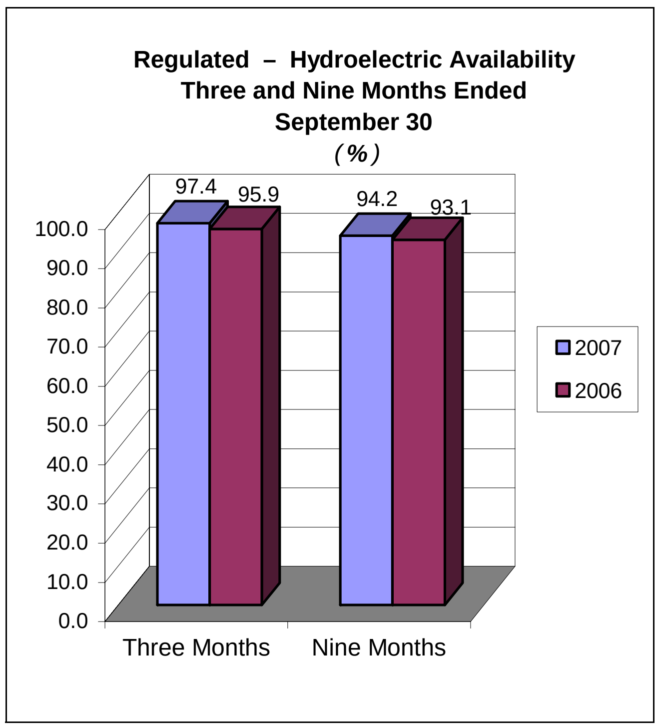
For the nine months ended September 30, 2007, electricity sales volume was 13.7 TWh compared to 13.5 TWh for the same period in 2006. The increase in electricity sales volume in 2007 was primarily due to higher water levels during the first half of 2007 on the St. Lawrence River, combined with an improvement in station availability.

Volume related to production levels above 1,900 MWh in any hour was 0.8 TWh during the third quarter of 2007 compared to 0.9 TWh for the same period in 2006. During the nine months ended September 30, 2007 electricity generation of 2.6 TWh related to production levels above 1,900 MWh in any hour compared to 2.5 TWh during the same period in 2006.




The EFOR for the Regulated – Hydroelectric stations during the three month periods ended September 30, 2007 and 2006 was 1.1 per cent. During the nine months ended September 30, 2007 and 2006, the EFOR for the Regulated – Hydroelectric stations was 1.1 per cent and 0.9 per cent, respectively.

The availability for the Regulated – Hydroelectric stations was 97.4 per cent for the three months ended September 30, 2007 compared to 95.9 per cent during the same period in 2006. During the nine months ended September 30, 2007, availability for the Regulated – Hydroelectric stations was 94.2 per cent compared to 93.1 per cent in the same period in 2006. The higher availability for the three and nine months ended September 30, 2007 compared to the same periods in 2006 was primarily due to shorter planned outages compared to the same periods in 2007.




*Variance Accounts*

OPG is required under a regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) to establish variance accounts for the Regulated – Hydroelectric segment to capture the impact of differences in hydroelectric electricity production due to differences between forecast and actual water conditions and differences between forecast and actual ancillary service revenue. For the three and nine month periods ended September 30, 2007, OPG recorded revenue of $9 million and $8 million, respectively, primarily as a result of actual water conditions and ancillary services revenue differed compared to the forecast provided to the Province for the purpose of establishing related prices.

*Fuel Expense*

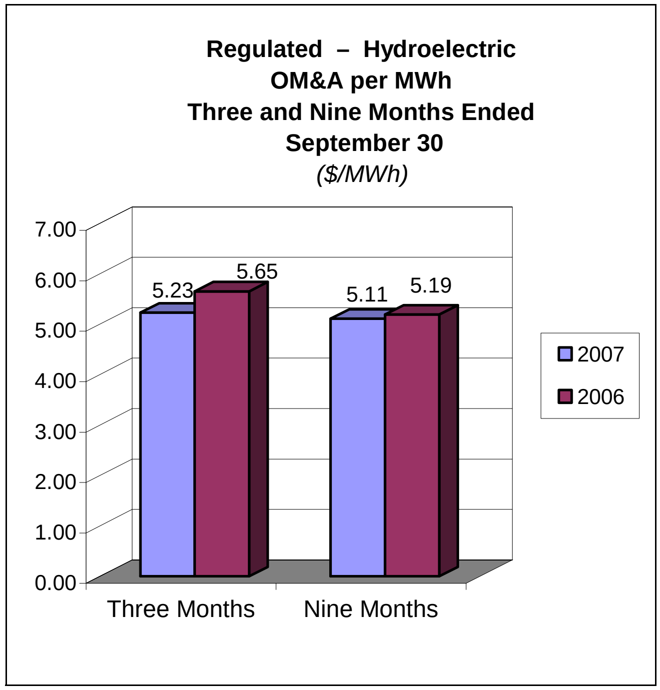
OPG pays charges to the Province and the OEFC on gross revenue derived from the annual generation of electricity from its hydroelectric generating assets. The gross revenue charge ("GRC") includes a fixed percentage charge applied to the annual hydroelectric generation derived from stations located on provincial Crown lands, in addition to graduated rate charges applicable to all hydroelectric stations. GRC costs are included in fuel expense. Fuel expense for the three months ended September 30, 2007 and 2006 was $60 million and $62 million, respectively. During the nine months ended September 30, 2007, fuel expense was $179 million compared to $174 million in 2006. The changes in fuel expense were primarily due to changes in generation volume.

*Operations, Maintenance and Administration*

OM&A expenses for the third quarter of 2007 were $23 million compared to $26 million for the same period in 2006.

For the nine months ended September 30, 2007, OM&A expenses were $97 million compared to $70 million during the same period in 2006. The increase in the OM&A expense for the nine months ended September 30, 2007 compared to the same period in 2006 was primarily due to an increase in expense related to past grievances by First Nations.

OM&A expense per MWh for the regulated hydroelectric stations was $5.23/MWh during the three months ended September 30, 2007 compared to $5.65/MWh during the same period in 2006. The decrease in OM&A expense per MWh for the three months ended September 30, 2007 compared to the same period in 2006 was primarily due to slightly lower OM&A expenses.




For the nine months ended September 30, 2007, OM&A expense per MWh for the regulated hydroelectric stations was $5.11/MWh compared to $5.19/MWh during the same period in 2006 primarily due to higher generation volume. OM&A expense per MWh excludes expenses related to past grievances by First Nations.

*Depreciation and Amortization*

Depreciation and amortization expense for the three months ended September 30, 2007 and 2006 was $16 million. During the nine months ended September 30, 2007 and 2006, depreciation expense was $50 million and $49 million, respectively.

**Unregulated – Hydroelectric Segment**

| (millions of dollars) | Three Months Ended September 30 2007 | 2006 | Nine Months Ended September 30 2007 | 2006 |
|---|---|---|---|---|
| Revenue net of revenue limit rebate | **146** | 117 | **533** | 545 |
| Fuel expense | **19** | 15 | **58** | 60 |
| Gross margin | **127** | 102 | **475** | 485 |
| Operations, maintenance and administration | **44** | 47 | **146** | 128 |
| Depreciation and amortization | **15** | 17 | **50** | 49 |
| Property and capital taxes | **3** | 4 | **8** | 11 |
| Income before interest and income taxes | **65** | 34 | **271** | 297 |

*Revenue*

| (millions of dollars) | Three Months Ended September 30 2007 | 2006 | Nine Months Ended September 30 2007 | 2006 |
|---|---|---|---|---|
| Spot market sales, net of hedging instruments | **155** | 121 | **554** | 561 |
| Revenue limit rebate | **(16)** | (16) | **(48)** | (42) |
| Other | **7** | 12 | **27** | 26 |
| Total revenue | **146** | 117 | **533** | 545 |

Unregulated – Hydroelectric revenue was $146 million for the three months ended September 30, 2007 compared to $117 million for the same period in 2006. The increase in revenue of $29 million during the third quarter of 2007 compared to the same period in 2006 was primarily due to higher electricity generation volume of 0.6 TWh.

Unregulated – Hydroelectric revenue was $533 million for the nine months ended September 30, 2007 compared to $545 million during the same period in 2006. The decrease in revenue of $12 million during the nine months ended September 30, 2007 compared to the same period in 2006 was primarily due to lower electricity generation volume in the first half of 2007.

*Electricity Prices*

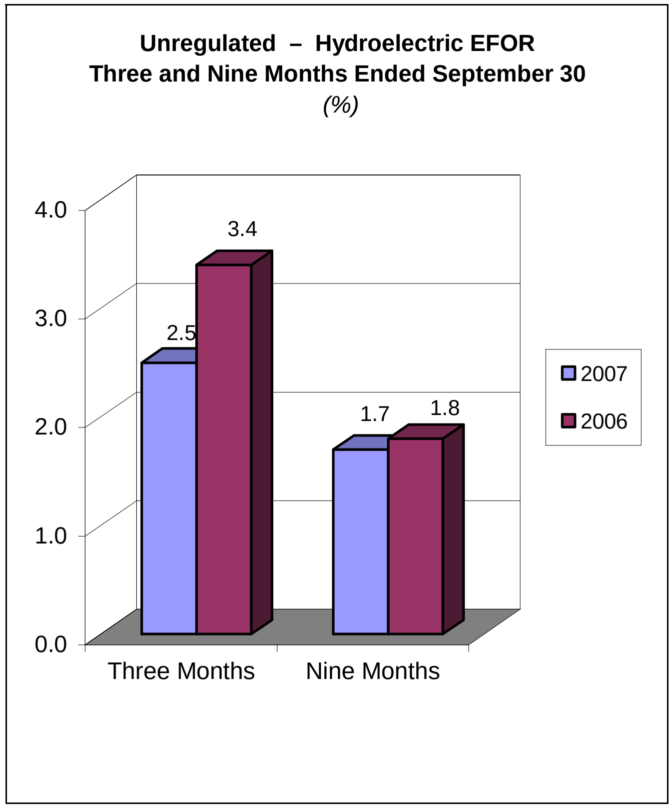
After taking into account the revenue limit rebate, OPG's average sales price for its unregulated hydroelectric generation for the three months ended September 30, 2007 and 2006 was 4.7¢/kWh and 4.6¢/kWh, respectively. OPG's average sales price for its unregulated hydroelectric generation for the nine months ended September 30, 2007 and 2006 was 4.7¢/kWh.

*Volume*

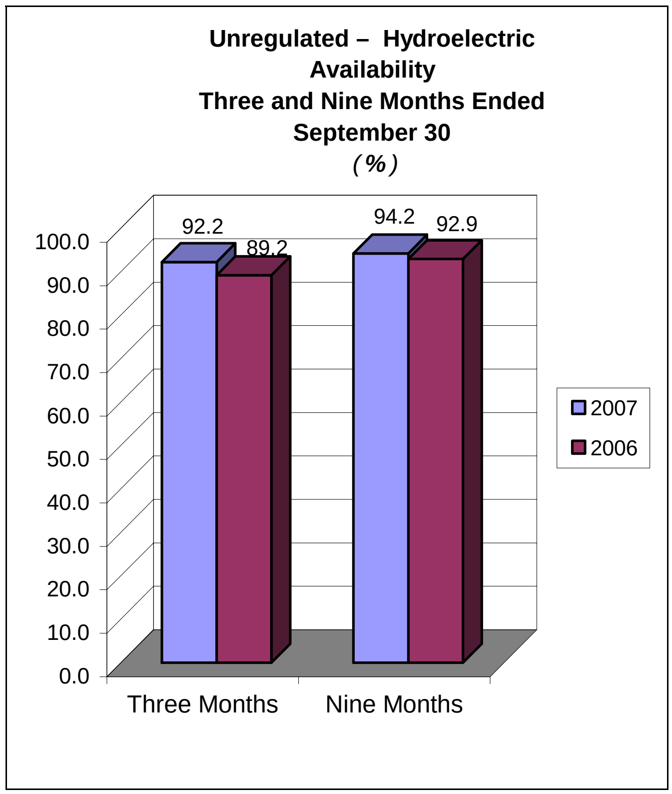
During the three months ended September 30, 2007, electricity sales volume was 2.8 TWh compared to 2.2 TWh for the three months ended September 30, 2006. The increase of 0.6 TWh was primarily due to higher water levels in the Northwestern part of the Province and higher station availability.

Electricity sales volume for the nine months ended September 30, 2007 was 10.6 TWh compared to 11.0 TWh during the same period in 2006. The decrease in volume of 0.4 TWh for the nine months ended September 30, 2007 compared to the same period in 2006 was primarily due to lower water levels in Eastern and Northeastern Ontario during the second and third quarter of 2007, and Northwestern Ontario during the first and second quarter of 2007.

The EFOR for the Unregulated – Hydroelectric stations was 2.5 per cent in the third quarter of 2007 compared to 3.4 per cent during the same quarter in 2006. For the nine months ended September 30, 2007, EFOR was 1.7 per cent compared to 1.8 per cent for the nine months ended September 30, 2006.




The availability for the Unregulated – Hydroelectric stations was 92.2 per cent for the three month period ended September 30, 2007 compared to 89.2 per cent for the same period last year. The availability for the Unregulated – Hydroelectric stations was 94.2 per cent for the nine months ended September 30, 2007 compared to 92.9 per cent for the nine months ended September 30, 2006.




The low EFOR and high availability reflect the strong performance of the Unregulated – Hydroelectric stations due to the continuing investment program.

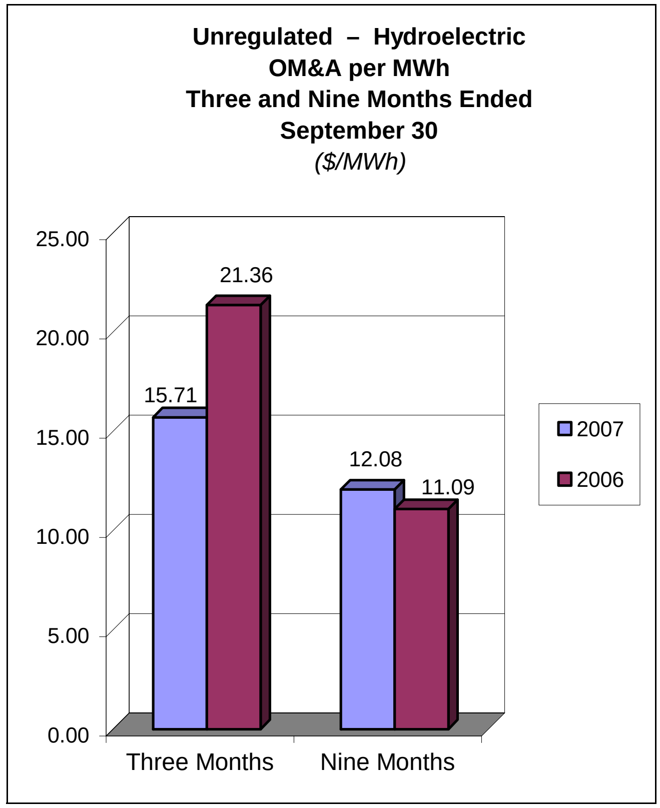
*Fuel Expense*

Generating stations within this segment are subject to the gross revenue charge. Fuel expense was $19 million during the three months ended September 30, 2007 compared to $15 million during the same period in 2006. During the nine months ended September 30, 2007 and 2006, fuel expense was $58 million and $60 million, respectively. The changes in fuel expense were a result of changes in generation volume.

*Operations, Maintenance and Administration*

OM&A expenses for the three months ended September 30, 2007 and 2006 were $44 million and $47 million, respectively.

During the nine months ended September 30, 2007, OM&A expenses were $146 million compared to $128 million for the same period in 2006. The increase in OM&A expenses for the nine months ended September 30, 2007 compared to the same period in 2006 was primarily due to an increase in expense related to past grievances by First Nations.




OM&A expense per MWh for the unregulated hydroelectric stations was $15.71/MWh in the third quarter of 2007 compared to $21.36/MWh for the same period in 2006. The lower OM&A expense per MWh for the three months ended September 30, 2007 was primarily due to higher generation volume compared to the same period in 2006.

During the nine months ended September 30, 2007, OM&A expense per MWh for the unregulated hydroelectric stations was $12.08/MWh compared to $11.09/MWh for the same period in 2006. The higher OM&A expense per MWh for the nine months ended September 30, 2007 was primarily due to lower generation and slightly higher OM&A expense compared to the same period in 2006.

OM&A expense per MWh excludes expense related to past grievances by First Nations.

*Depreciation and Amortization*

Depreciation and amortization expense for the three months ended September 30, 2007 and 2006 was $15 million and $17 million, respectively. Depreciation expense for the nine months ended September 30, 2007 and 2006 was $50 million and $49 million, respectively.

**Unregulated – Fossil-Fuelled Segment**

| *(millions of dollars)* | Three Months Ended September 30 2007 | 2006 | Nine Months Ended September 30 2007 | 2006 |
|---|---|---|---|---|
| Revenue, net of revenue limit rebate | **439** | 379 | **1,213** | 1,044 |
| Fuel expense | **224** | 199 | **627** | 504 |
| Gross margin | **215** | 180 | **586** | 540 |
| Operations, maintenance and administration | **130** | 115 | **414** | 375 |
| Depreciation and amortization | **20** | 17 | **59** | 113 |
| Accretion on fixed asset removal liabilities | **3** | 2 | **7** | 7 |
| Property and capital taxes | **5** | 7 | **16** | 15 |
| Income before interest and income taxes | **57** | 39 | **90** | 30 |

*Revenue*

| *(millions of dollars)* | Three Months Ended September 30 2007 | 2006 | Nine Months Ended September 30 2007 | 2006 |
|---|---|---|---|---|
| Spot market sales, net of hedging instruments | **455** | 398 | **1,242** | 1,055 |
| Revenue limit rebate | **(44)** | (43) | **(128)** | (106) |
| Other | **28** | 24 | **99** | 95 |
| Total revenue | **439** | 379 | **1,213** | 1,044 |

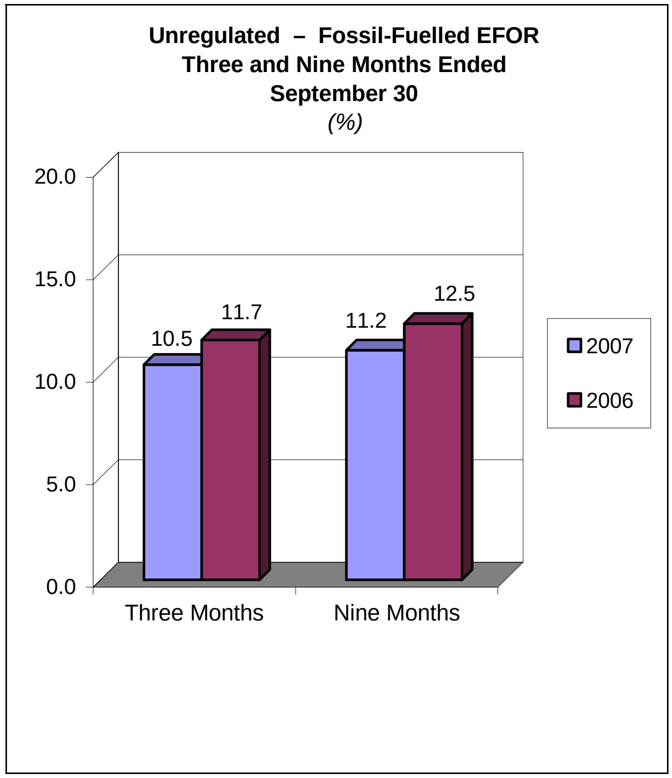
Unregulated – Fossil-Fuelled revenue was $439 million for the three months ended September 30, 2007 compared to $379 million for the same period in 2006, an increase of $60 million. Unregulated – Fossil-Fuelled revenue was $1,213 million for the nine months ended September 30, 2007 compared to $1,044 million for the same period in 2006, an increase of $169 million. The increase in revenue during the three and nine months ended September 30, 2007 compared to the same periods in 2006 was primarily due to higher electricity generation volumes of 0.9 TWh and 3.0 TWh, respectively.

*Electricity Prices*

OPG’s average sales price net of the revenue limit rebate for its unregulated fossil-fuelled generation was 4.9¢/kWh for the three months ended September 30, 2007 and 4.8¢/kWh for the same period in 2006. During the nine months ended September 30, 2007 and 2006, OPG’s average sales price net of the revenue limit rebate for its unregulated fossil-fuelled generation was 4.9¢/kWh and 4.8¢/kWh, respectively.

*Volume*

Electricity sales volume for the three months ended September 30, 2007 was 8.2 TWh compared to 7.3 TWh during the same period in 2006. The increase of 0.9 TWh was primarily due to the significantly lower generation from the nuclear generating stations, partly offset by the impact of lower primary electricity demand.




Electricity sales volume for the nine months ended September 30, 2007 was 22.6 TWh compared to 19.6 TWh during the same period in 2006. The increase of 3.0 TWh in 2007 was primarily due to lower nuclear generation in Ontario in the first nine months of 2007 compared to the same period in 2006.

The EFOR for the Unregulated **–** Fossil-Fuelled stations during the three months ended September 30, 2007 was 10.5 per cent compared to 11.7 per cent during the same period in 2006.

During the nine months ended September 30, 2007 and 2006, the EFOR for the Unregulated – Fossil-Fuelled stations was 11.2 per cent and 12.5 per cent, respectively.

*Fuel Expense*

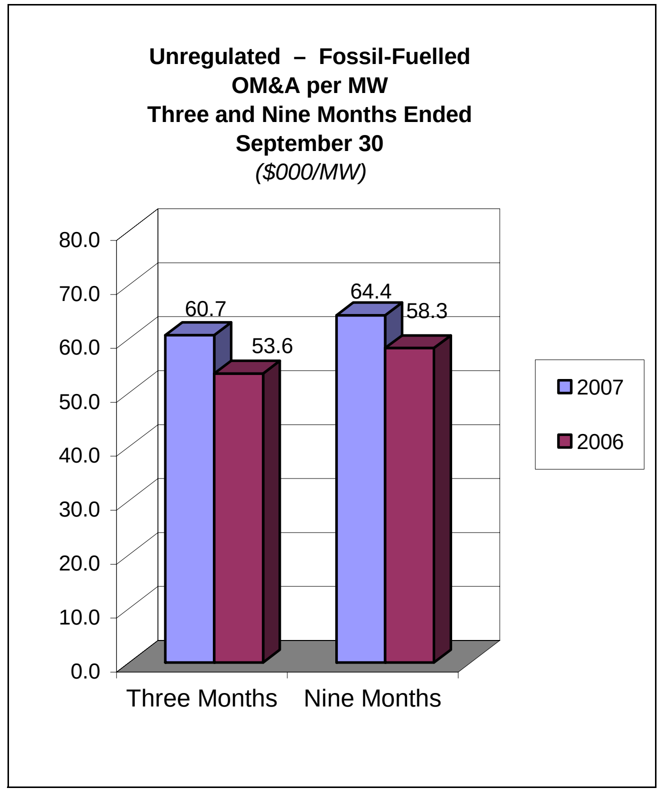
Fuel expense was $224 million for the three months ended September 30, 2007 compared to $199 million for the same period in 2006. During the nine months ended September 30, 2007, fuel expense was $627 million compared to $504 million during the nine months ended September 30, 2006. The increases for the three and nine month periods ended September 30, 2007 were primarily due to higher electricity generation. In addition, during the nine months ended September 30, 2007, fuel expense was higher partly due to higher coal purchase costs under long-term supply contracts.

*Operations, Maintenance and Administration*

OM&A expenses for the three months ended September 30, 2007 were $130 million compared to $115 million for the same period in 2006. The increase of $15 million was mainly due to increased maintenance programs and projects related to the extended period over which the coal-fired generating stations will be required to operate.

OM&A expenses for the nine months ended September 30, 2007 were $414 million compared to $375 million during the nine months ended September 30, 2006. The increase of $39 million was primarily due to increased maintenance programs and projects related to the extended period over which the coal-fired generating stations will be required to operate, partially offset by the write-off of unrecoverable costs in 2006 related to the cancellation of the Thunder Bay generating station gas conversion project.

Annualized OM&A expense per MW ($/MW) for the unregulated fossil-fuelled stations increased to $60,700/MW for the three months ended September 30, 2007 compared to $53,600/MW for the three months ended September 30, 2006. During the nine months ended September 30, 2007, annualized OM&A expense per MW was $64,400/MW compared to $58,300/MW for the same period in 2006. The increase primarily reflected the impact of the higher OM&A expenses related to the extension of the service lives of the coal-fired generating stations.




*Depreciation and Amortization*

Depreciation and amortization expense for the three months ended September 30, 2007 was $20 million, compared to $17 million for the same period in 2006. The increase in depreciation and amortization expense was primarily due to additions to the asset base of the fossil-fuelled generating stations.

Depreciation and amortization expense for the nine months ended September 30, 2007 and 2006 was $59 million and $113 million, respectively. The decrease in depreciation and amortization expense in 2007 was primarily due to the extension of the service lives of the coal-fired generating stations, for the purpose of calculating depreciation and amortization, due to the delay in the coal replacement program announced by the Ministry of Energy in June 2006. OPG will continue to assess the service lives of the coal-fired stations.

**Other**

| | **Three Months Ended September 30** | | **Nine Months Ended September 30** | |
|---|---|---|---|---|
| *(millions of dollars)* | **2007** | **2006** | **2007** | **2006** |
| Revenue | **36** | 42 | **103** | 118 |
| Operations, maintenance and administration | **5** | - | **6** | (5) |
| Depreciation and amortization | **13** | 13 | **40** | 39 |
| Property and capital taxes | **3** | 3 | **9** | 8 |
| Income before interest and income taxes | **15** | 26 | **48** | 76 |

Other revenue was $36 million for the three months ended September 30, 2007 compared to $42 million for the same period in 2006. The decrease in revenue was primarily due to lower net trading revenue.

Other revenue for the nine months ended September 30, 2007 was $103 million compared to $118 million in the same period in 2006. The decrease in revenue was primarily due to significantly lower net trading revenue, partly offset by an increase in investment income from OPG's equity investments.

OM&A expenses of the generation business segments include an inter-segment service fee for the use of certain property, plant and equipment held within the Other category. The total service fee is recorded as a reduction to the Other category's OM&A expenses. For the three months ended September 30, 2007, the service fee was $11 million for Regulated – Nuclear, $1 million for Regulated – Hydroelectric, $1 million for Unregulated – Hydroelectric, $4 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $17 million for the Other category. For the three months ended September 30, 2006, the service fee was $9 million for Regulated – Nuclear, $1 million for Regulated – Hydroelectric, $1 million for Unregulated – Hydroelectric, $2 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $13 million for the Other category.

For the nine months ended September 30, 2007, the service fee was $25 million for Regulated – Nuclear, $2 million for Regulated – Hydroelectric, $3 million for Unregulated – Hydroelectric, $8 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $38 million for the Other category. For the nine months ended September 30, 2006, the service fee was $23 million for Regulated – Nuclear, $2 million for Regulated – Hydroelectric, $3 million for Unregulated – Hydroelectric, $7 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $35 million for the Other category.

Interconnected markets 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 interim consolidated statements of income. If disclosed on a gross basis, revenue and power purchases for the three months ended September 30, 2007 would have increased by $26 million (three months ended September 30, 2006 – $38 million). For the nine months ended September 30, 2007, if disclosed on a gross basis, revenue and power purchases would have increased by $90 million (nine months ended September 30, 2006 – $127 million).

The changes in the fair value of derivative instruments not qualifying for hedge accounting are recorded in Other revenue, and are carried on the interim consolidated balance sheets as assets or liabilities at fair value. The carrying amounts and notional quantities of the derivative instruments are disclosed in Note 12 in the unaudited interim consolidated financial statements as at and for the three and nine months ended September 30, 2007.

**Net Interest Expense**

The net interest expense for the three months ended September 30, 2007 was $37 million compared to $47 million for the same period in 2006. The net interest expense for the nine months ended September 30, 2007 was $102 million compared to $145 million for the same period in 2006. The decrease in net interest expense for the three and nine month periods ended September 30, 2007 was primarily due to the deferral of additional interest expense related to the Pickering A return to service deferral account as required by the amended regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario).

**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 or refunded through future regulated prices charged to customers.

Income tax expense for the third quarter of 2007 was $26 million compared to $51 million for the same period in 2006. The lower tax expense in 2007 was primarily due to lower income before tax and lower taxable income. During the third quarter of 2007 and 2006, the income tax expense was lower than what would otherwise have been recorded had OPG accounted for income tax for the regulated segments using the liability method by $20 million and $24 million, respectively.

Income tax expense for the nine months ended September 30, 2007 was $112 million compared to $149 million for the same period in 2006, primarily due to lower income before tax in 2007. This was partly offset by the impact of the reduction in future income tax rates enacted in 2006. For the nine months ended September 30, 2007 and 2006, income tax expense was lower than what would otherwise have been recorded had OPG accounted for income tax for the regulated segments using the liability method by $61 million and the $42 million, respectively.

The transition adjustment to the accumulated other comprehensive income on adoption of the financial instruments accounting standards was lower by $4 million than what would otherwise have been recorded had OPG utilized the liability method of tax accounting for the regulated segments.

In the third quarter of 2006, OPG received a preliminary communication from the Provincial Tax Auditors ("Tax Auditors") with respect to their initial findings from their audit of OPG's 1999 taxation year. Many of the issues raised through the audit are unique to OPG and relate either to start-up matters and positions taken on April 1, 1999 upon commencement of operations, or matters that were not adequately addressed through the Electricity Act, 1998. Although OPG has subsequently resolved some of these issues, there is uncertainty as to how the remaining issues will be resolved. OPG expects to receive a reassessment for its 1999 taxation year. The Company would defend its position through the tax appeals process.

OPG has previously recorded income tax charges related to certain income tax positions that the Company has taken in prior years that may be disallowed. Given the uncertainty as to how these income tax matters will be resolved, OPG has not adjusted its income tax liabilities. Should the ultimate outcome differ from OPG's recorded income tax liabilities, the Company's effective tax rate and its net income could be materially affected either negatively or positively in the period in which the matters are resolved.

## 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 sources are utilized for continued investment in plant and technologies, and to meet other significant funding obligations including contributions to the pension fund, the Used Fuel Segregated Fund ("Used Fuel Fund") and Decommissioning Segregated Fund ("Decommissioning Fund") (together, the "Nuclear Funds"), and to service and repay long-term debt and revenue limit rebate obligations.

| | **Three Months Ended September 30** | | **Nine Months Ended September 30** | |
|---|---|---|---|---|
| *(millions of dollars)* | **2007** | **2006** | **2007** | **2006** |
| Cash and cash equivalents, beginning of period | **138** | 360 | **6** | 908 |
| Cash flow provided by operating activities | **248** | 307 | **723** | 306 |
| Cash flow (used in) investing activities | **(292)** | (191) | **(627)** | (435) |
| Cash flow provided by (used in) financing activities | **38** | (301) | **30** | (604) |
| Net increase (decrease) | **(6)** | (185) | **126** | (733) |
| Cash and cash equivalents, end of period | **132** | 175 | **132** | 175 |

### Operating Activities

Cash flow provided by operating activities for the three months ended September 30, 2007 was $248 million compared to cash flow provided by operating activities of $307 million during the same period in 2006. The decrease in cash flow was primarily due to higher operating and maintenance expenditures, a higher revenue limit rebate payment, and lower cash receipts from electricity sales, partially offset by the increase in non-electricity generation revenue.

Cash flow provided by operating activities for the nine months ended September 30, 2007 was $723 million compared to cash flow provided by operating activities of $306 million during the same period in 2006. The increase in cash flow was primarily due to lower revenue limit rebate payments, a higher reimbursement of expenditures for nuclear fixed asset removal and nuclear waste management during the first nine months of 2007 compared to the same period in 2006, and lower payments for fossil fuel. The increase in cash flow is partially offset by a decrease in cash receipts from electricity sales and higher operating and maintenance expenditures. The lower revenue limit rebate payments for the nine months ended September 30, 2007 compared to the same period in 2006 was a result of making a payment of $739 million in the second quarter of 2006 related to the period April 1, 2005 to December 31, 2005. Revenue limit rebate payments are now made on a quarterly basis.

### Investing Activities

OPG is in a capital-intensive business that requires continued investment in plant and technologies to improve operating efficiencies, increase generating capacity of its existing stations, invest in new generating stations and to maintain and improve service, reliability, safety and environmental performance.

Investment in fixed assets during the three months ended September 30, 2007 was $179 million compared with $188 million during the same period in 2006. This decrease in capital expenditures was primarily due to a lower investment in the Niagara Tunnel project, partially offset by higher capital investments in fossil-fuelled and nuclear facilities. For the nine months ended September 30, 2007, investment in fixed assets was $476 million compared with $422 million for the nine months ended September 30, 2006. The increase in capital expenditures for the nine months ended September 30, 2007 was primarily due to a higher investment in the Portlands Energy Centre and investments in fossil-fuelled and nuclear facilities, partially offset by a lower investment in the Niagara Tunnel project.

OPG's forecast capital expenditures for 2007 are approximately $700 million, which include amounts for the Niagara Tunnel project, Portlands Energy Centre and the Lac Seul project.

For the three months ended September 30, 2007, investing activities included costs related to OPG's regulatory assets of $10 million compared to $1 million during the same period in 2006. The amount deferred during the three months ended September 30, 2007, and reflected in the investing activities, included non-capital costs incurred for nuclear generation development initiatives, and interest expense related to the Pickering A return to service deferral account.

For the nine months ended September 30, 2007, investing activities included costs deferred as regulatory assets of $48 million compared to $13 million during the same period in 2006. The amount deferred as regulatory assets during the nine months ended September 30, 2007 included interest expense related to the Pickering A return to service deferral account, and non-capital costs incurred for nuclear generation development initiatives.

During the third quarter of 2007, OPG reclassified $103 million of ABCP notes held by OPG from cash and cash equivalents to short-term investments. A discussion of OPG's exposure to the ABCP notes is included in the *Recent Development* section.

### Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility which is divided into two tranches – a $500 million 364-day term tranche maturing May 21, 2008 and a $500 million five-year term tranche maturing May 22, 2012. The longer term tranche was extended from a three-year term to a five-year term, upon renewal of the bank credit facility in May 2007. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. As at September 30, 2007, no commercial paper was outstanding (December 31, 2006 – $15 million). OPG had no other outstanding borrowings under the bank credit facility.

OPG also maintains $25 million (December 31, 2006 – $26 million) in short-term uncommitted overdraft facilities and $238 million (December 31, 2006 – $240 million) of short-term uncommitted credit facilities, which support the issuance of Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans, and for other purposes including the requirement to post Letters of Credit as collateral with Local Distribution Companies ("LDCs") as prescribed by the OEB's Retail Settlement Code. At September 30, 2007, there was a total of $201 million of Letters of Credit issued (December 31, 2006 – $185 million), which included $175 million for the supplementary pension plans (December 31, 2006 – $159 million) and $16 million related to the construction of the Portlands Energy Centre (December 31, 2006 – $16 million).

OPG negotiated an agreement with the OEFC to finance the Niagara Tunnel project for up to $1 billion over the duration of the project. The funding is advanced in the form of 10-year notes, on commercial terms and conditions. Advances under this facility commenced in October 2006, and amounted to $240 million as at September 30, 2007. OPG did not incur additional borrowing during the three months ended September 30, 2007. Similarly, debt financing has been negotiated with the OEFC for OPG's interest in the Portlands Energy Centre and the Lac Seul project for up to $400 million and $50 million, respectively. Advances under these facilities commenced in December 2006, and totalled $160 million for the Portlands Energy Centre and $20 million for the Lac Seul projects as at September 30, 2007. This included $40 million of new borrowing under the Portlands Energy Centre facility during the three months ended September 30, 2007. OPG did not draw on additional borrowing under the Lac Seul facility during the third quarter of 2007.

As at September 30, 2007, OPG's long-term debt outstanding with the OEFC was $3.2 billion. Although the new financing added in 2006 and 2007 has extended the maturity profile, approximately $2.6 billion of long-term debt must be repaid or refinanced within the next five years. To ensure that adequate financing resources are available beyond its $1 billion commercial paper program backed by the bank credit facility, OPG reached an agreement with the OEFC for a $500 million general corporate facility that is available for the period June 1, 2007 to March 31, 2008. OPG also reached an agreement with the OEFC for a $950 million credit agreement to refinance senior notes as they mature over the period September 2007 to September 2009.

In June 2007, OPG borrowed $100 million under the general corporate facility. In September 2007, OPG met its debt retirement obligation by issuing $200 million of notes under the $950 million credit facility to refinance the maturing notes. These borrowings will mature in 2017.

## 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 2006 annual audited consolidated financial statements, except as disclosed in Note 2 to the unaudited interim consolidated financial statements.

Certain of the accounting policies disclosed in OPG's 2006 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 2006 annual MD&A under the heading, *Critical Accounting Policies and Estimates*.

On January 1, 2007, the Company adopted the CICA Handbook Sections 3855, *Financial Instruments – Recognition and Measurement*, 3865, *Hedges*, 1530, *Comprehensive Income*, 3251 *Equity*, and 3861, *Financial Instruments – Disclosure and Presentation*. These standards have been applied prospectively with transition adjustments to opening retained earnings of $513 million and accumulated other comprehensive income ("AOCI") of $21 million. The impact of adoption is further disclosed in Note 2 to the unaudited interim financial statements.

**Future Changes in Accounting Policies and Estimates**

*Capital Disclosures*

The CICA issued an accounting standard, Section 1535, *Capital Disclosures*, in December 2006, which requires the disclosure of both qualitative and quantitative information that enables users of financial statements to evaluate the entity's objectives, policies and processes for managing capital. The standards also require companies to disclose if the company has complied with any capital requirements, and, if it has not complied, the consequences of such non-compliance. This new accounting standard will be effective for the Company beginning January 1, 2008. OPG is evaluating the impact of this new standard on its consolidated financial statements.

*Financial Instruments – Disclosure and Presentation*

OPG will be required to adopt Section 3862, *Financial Instruments – Disclosures*, and Section 3863, *Financial Instruments – Presentation*. These standards were issued in December 2006 and will replace Section 3861, *Financial Instruments – Disclosure and Presentation*. The new disclosure standard increases the emphasis on the risk associated with both recognized and unrecognized financial instruments and how those risks are managed. The new presentation standards carry forward the former presentation requirements under the existing Section 3861. These new accounting standards will be effective for OPG beginning January 1, 2008. OPG is assessing the impact of the new standards on its consolidated financial statements.

*Inventories*

The CICA issued a new accounting standard, Section 3031, *Inventories*, in March 2007, which is based on International Accounting Standard ("IAS") 2. The new section replaced the existing Section 3030, *Inventories*. Under the new section, inventories are required to be measured at the "lower of cost and net realizable value", which is different from the existing guidance of the "lower of cost and market". The new section also allows the reversal of any write-downs previously recognized. Further, due to the changes in the section and the consequential amendments, some of OPG's critical spare parts currently reported as materials and supplies on OPG's consolidated balance sheet may be accounted for in the future as property, plant and equipment. The new accounting standard and any consequential amendments will be effective for OPG beginning January 1, 2008. OPG is in the process of assessing the impact of the new standard.

## 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**<br>*(millions of dollars)* | **As at**<br>**September 30**<br>**2007** | <br>**December 31**<br>**2006** |
|---|---|---|
| Assets | | |
| Accounts receivable | **230** | 230 |
| Property, plant and equipment – net | **12,761** | 12,761 |
| Nuclear fixed asset removal and nuclear waste management funds | **8,743** | 7,594 |
| Regulatory assets | **324** | 251 |
| Liabilities | | |
| Accounts payable and accrued charges | **824** | 989 |
| Revenue limit rebate payable | **67** | 40 |
| Long-term debt (including debt due within one year) | **3,404** | 3,359 |
| Fixed asset removal and nuclear waste management | **10,857** | 10,520 |
| Other post employment benefits and supplementary pension plans (long-term portion) | **1,529** | 1,396 |

### Accounts Receivable

As at September 30, 2007 and December 31, 2006, accounts receivable were unchanged at $230 million.

### Property, Plant and Equipment – Net

Net property, plant and equipment as at September 30, 2007 and December 31, 2006 was $12,761 million. Depreciation expense for the nine months ended September 30, 2007 was offset by additions to fixed assets during the same period.

### Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

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

To fund these liabilities, OPG established and manages, jointly with the Province, a Used Fuel Fund and a Decommissioning Fund, which are funded by OPG in accordance with the ONFA. The Used Fuel Fund is primarily 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 and trustee accounts that are segregated from the rest of OPG's assets.

Assets in the Nuclear Funds are invested in fixed income and equity securities. The Nuclear Funds are referred to as the nuclear fixed asset removal and nuclear waste management funds in OPG's consolidated financial statements. Until December 31, 2006, OPG recorded the assets in the Nuclear Funds as long-term investments at their amortized cost. Up to and including December 31, 2006, gains and losses were recognized only upon the sale of an underlying security. As such, any unrealized gains and losses associated with the investments in the Nuclear Funds were not recognized in OPG's consolidated financial statements. As at December 31, 2006, the value of the Nuclear Funds on an amortized cost basis was $7,594 million.

Effective January 1, 2007, OPG adopted the CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement*. As a result of the adoption of this new section, the investments in the Nuclear Funds and the corresponding payables to the Province are classified as held-for-trading and are measured at fair value with realized and unrealized gains and losses recognized in OPG's consolidated financial statements.

*Decommissioning Fund*

Upon termination of the ONFA, the Province has a right to any excess funding in the Decommissioning Fund, which is the excess of the fair market value of the Decommissioning Fund over the estimated completion costs as per the most recently approved ONFA reference plan. When the Decommissioning Fund is overfunded, OPG limits 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 balance of the Decommissioning Fund would equal the cost estimate of the liability based on the most recently approved ONFA reference plan. The payable to the Province could be reduced in subsequent periods in the event that the Decommissioning Fund earns less than its target rate of return or in the event that a new ONFA reference plan is approved with a higher estimated decommissioning liability. At December 31, 2006, based on the estimate of costs to complete under the 2006 Approved Reference Plan, the Decommissioning Fund was overfunded on a fair value basis, and underfunded on an amortized cost basis.

As a result of the adoption of the financial instruments accounting standards on January 1, 2007, OPG adjusted the investments and the related payables in the Decommissioning Fund, to fair value and recorded a transition adjustment of $519 million to increase opening retained earnings. Subsequently, the investments and the related payables in the Decommissioning Fund are measured at fair value and any changes to the fair values are recognized in income.

On January 1, 2007, because the fair value of the investments in the Decommissioning Fund exceeded the estimated completion costs under the 2006 Approved Reference Plan, the Decommissioning Fund balance was reduced by the amount of the excess funding through the recording of a payable to the Province. The Province's right to any excess funding in the Decommissioning Fund upon termination of the ONFA results in OPG capping its earnings at 5.15 per cent, which is the rate of growth in the liability for the estimated completion cost, as long as the Decommissioning Fund is in an overfunded status. If the Decommissioning Fund were underfunded, the earnings for the Decommissioning Fund would reflect actual fund returns based on the market value of the assets.

At September 30, 2007, the Decommissioning Fund asset value on a fair value basis was $5,157 million, which continued to exceed the value of the liability as per the 2006 Approved Reference Plan. As a result of the overfunded status, OPG reported a payable to the Province of $136 million. Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 per cent funded, OPG may direct up to 50 per cent of the surplus over 120 per cent to be treated as a contribution to the Used Fuel Fund, and the OEFC is entitled to a distribution of an equal amount.

*Used Fuel Fund*

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Fund at 3.25 per cent plus the change in the Ontario CPI ("committed return") for funding related to the first 2.23 million used fuel bundles. 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 recorded as due to or due from the Province.

Up until December 31, 2006, OPG accounted for the investments in the Used Fuel Fund on an amortized cost basis, with the amount due to or due from the Province being recorded in the consolidated financial statements as the difference between the committed return and the actual return based on realized returns. At December 31, 2006, the Used Fuel Fund included an amount due to the Province of $100 million. The Used Fuel Fund asset value, after taking into account the committed return and the amount due to the Province, was $3,238 million at December 31, 2006. 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.

Commencing January 1, 2007, the value of the investments held in the Used Fuel Fund is measured at fair value. Accordingly, the Used Fuel Fund balance increased to $3,876 million to reflect the fair value measurement. The Province guarantees OPG's annual return in the Used Fuel Fund related to the initial 2.23 million used fuel bundles at the committed return, such that any difference between the committed return and the actual return based on fair value would be offset by the change in the related payable or receivable to the Province in the Used Fuel Fund. As a result, OPG did not record a transition adjustment to opening retained earnings for the Used Fuel Fund.

As at September 30, 2007, the Used Fuel Fund asset value on a fair value basis was $4,286 million. The asset value was offset by a payable to the Province of $564 million related to the committed return adjustment.

**Regulatory Assets**

As at September 30, 2007, regulatory assets were $324 million compared to $251 million as at December 31, 2006. In accordance with the amendment to the regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario), during the nine months ended September 30, 2007, OPG recorded $97 million in the deferral account related to the increase in OPG's liabilities for nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management arising from the 2006 Approved Reference Plan. The recognition of the regulatory asset for this deferral account reduced additional expenses resulting from the increase in the nuclear liabilities. These expenses included accretion on the fixed asset removal and nuclear waste management liabilities and depreciation of the carrying value of the related fixed assets. During the nine months ended September 30, 2007, OPG also deferred $20 million of non-capital costs incurred for nuclear generation development initiatives.

The increase in the regulatory assets was partially offset by the reduction in the balance of the Pickering A return to service deferral account due to amortization expense of $76 million during the nine months ended September 30, 2007. The impact of the amortization related to the Pickering A return to service deferral account was partly offset by the deferral of $27 million of interest expense related to the balance in the deferral account as prescribed by the amended regulation.

**Accounts Payable and Accrued Charges**

Accounts payable and accrued charges as at September 30, 2007 were $824 million compared to $989 million as at December 31, 2006. The decrease was primarily due to reduced accrued interest due to the timing of interest payments, lower payroll related accruals, and lower trade accounts payable, including lower uranium purchases.

**Revenue Limit Rebate Payable**

The revenue limit rebate payable as at September 30, 2007 was $67 million compared to $40 million as at December 31, 2006. The increase was due to a revenue limit rebate of $176 million for the nine months ended September 30, 2007, net of rebate payments of $149 million during the same period.

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

Long-term debt as at September 30, 2007 was $3,404 million compared to $3,359 million as at December 31, 2006. The increase was primarily due to the issuance of long-term debt of $200 million under the credit agreement to refinance senior notes, $150 million related to committed capital projects, and $100 million under the general corporate facility. The increase was largely offset by repayment of long-term debt of $405 million, which included amounts issued under the credit agreement to refinance senior notes.

### Fixed Asset Removal and Nuclear Waste Management

The liability for fixed asset removal (for nuclear and fossil-fuelled generating stations) and nuclear waste management as at September 30, 2007 was $10,857 million compared to $10,520 million as at December 31, 2006. The increase 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 $1,529 million as at September 30, 2007 compared to $1,396 million as at December 31, 2006. The increase of $133 million was due to costs recognized in the first nine months of 2007, net of benefit payments.

### Accumulated Other Comprehensive Income

Effective January 1, 2007, OPG adopted the CICA Handbook Section 3865 – *Hedges*, and recognized hedging instruments designated as cash flow hedges in opening AOCI on a net of tax basis. At the same time, the fair value of the hedging instruments was recorded in OPG's interim consolidated balance sheets. Subsequent adjustments arising due to these hedging instruments are also recognized in AOCI on a net of tax basis. Prior to January 1, 2007, hedging instruments that qualified for hedge accounting were not carried at fair value on the consolidated balance sheets and were disclosed as off-balance sheet items.

The majority of OPG's derivative instruments are treated as hedges, with gains or losses recognized in income upon settlement of the underlying transactions. 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 USD denominated purchases. Interest rate derivative contracts are used to hedge exposure to changes in market interest rates on variable debt and on debt expected to be issued in the future. When a derivative instrument is expired, the designation of a hedging relationship is terminated, or a portion of the hedging instrument is no longer effective, any associated gains or losses included in AOCI are recognized in the current period's consolidated statement of income. As at September 30, 2007, OPG reported AOCI of $32 million.

For additional information, refer to Note 12 of OPG's unaudited interim consolidated financial statements for the three and nine months ended September 30, 2007.

### 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 in the Company's consolidated financial statements in amounts that differ from the full contract amounts. Principal off-balance sheet activities that OPG undertakes include securitization of certain accounts receivable agreements, guarantees, which provide financial or performance assurance to third parties on behalf of certain subsidiaries, and 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 September 30, 2007, the average all-in cost of funds was 5.2 per cent (three months ended September 30, 2006 – 4.6 per cent) and the pre-tax charges on sales to the trust were $4 million (three months ended September 30, 2006 – $4 million).

For the nine months ended September 30, 2007, the average all-in cost of funds was 4.9 per cent (nine months ended September 30, 2006 – 4.4 per cent) and the pre-tax charges on sales to the trust were $11 million (nine months ended September 30, 2006 – $10 million).

The current securitization agreement extends to August 2009. Refer to Notes 3 and 4 of OPG's 2006 annual consolidated financial statements for additional information.

*Guarantees*

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

## RISK MANAGEMENT

A detailed discussion of OPG's operational, financial, and strategic risks is included in the 2006 annual MD&A under the heading, *Risk Management*. The sections which follow provide updates to this disclosure.

### Operational Risks

OPG is exposed to the financial impacts of uncertain output from its generating stations. The amount of electricity generated by OPG is affected by a number of factors including fuel supply, equipment malfunction or deterioration, maintenance requirements, water levels, and regulatory and environmental regulations. The primary unfavourable impacts of these factors are higher cost of operations, reduced revenues and the potential derating of a generating unit resulting in production that is lower than its normal level of output.

*Regulated – Nuclear Segment Generation Risks*

The uncertainty associated with the volume of electricity produced by OPG's nuclear generating units is primarily driven by equipment performance and degradation in the condition of the plant components and systems. Management of these risks is primarily through the execution of an extensive maintenance program, that is consistent with industry best practices, detailed plant condition assessments and lifecycle equipment management programs designed to maintain the equipment in safe working order until the end of its design life.

In certain cases, deterioration progresses or materials change properties in an unexpected manner, resulting in increased monitoring, extensive repairs, additional remedial measures or the derating of the units in order to maintain a safe operating margin. When such a technology risk first appears or is suspected, a specific monitoring program is established. If the risk exposure materializes, a resolution program is initiated. The primary impact of these technology risks is an increase in the cost of operations. One resolution program currently underway is the replacement of piping components, known as feeders. Feeders are part of the system that transports heat from the reactors to the steam generators that feed the turbines producing electricity. Certain feeders have shown degradation beyond expectations, and will be replaced under a multi-year program.

In addition to remediation measures, monitoring and inspections, initiatives with respect to technology and plant deterioration risks also include the sharing of operating experiences and information with other nuclear operators who participate in industry-wide or shared research programs, as well as the development of investigative methods and remediation tools or methods.

*Nuclear Regulatory Uncertainty*

Another effect of plant deterioration or technology risks is their impact on nuclear regulation and the changes they bring to technical codes. Operating experience around the world also contributes new knowledge and understanding of both nuclear operations and safety issues, resulting in continually evolving regulatory rules and the refinement of safety measurements and assessments. Remaining current with and addressing these unexpected changes adds to the cost of operations and in some instances, it may result in a reduction in the productive capacity of a plant, or in the earlier than planned replacement of a plant component. As there is currently no single, uniform, prescribed methodology to assess nuclear safety, OPG and its regulator may develop differing expectations about the timing or extent of any remediation needed. While such situations are normally resolved through subsequent detailed reviews and discussions, they contribute to the uncertainty of the regulatory requirements.

Regulatory uncertainty remains a significant risk for all activities and programs related to nuclear plant life extension, rehabilitation, new plant construction and decommissioning, such as the Pickering A Units 2 and 3 safe storage project as existing standards, designed for plant operations, do not readily extend to new conditions or designs. The primary effects of this risk are project delays and higher development costs.

OPG manages regulatory uncertainty risk by maintaining close contact with the regulator and issuers of standards and codes for the early identification and discussions of issues. Together with other industry members, OPG is pursuing the use of a common, risk-based mode of assessment and regulation.

*Hydroelectric Segment Generation Risks*

OPG's hydroelectric generating performance is partially dependent on the availability of water, which can vary from year to year due in large part to the weather. The inherent uncertainty in forecasting water levels introduces a significant degree of uncertainty with respect to forecasting hydroelectric generation. OPG manages this risk by using production forecasting models that incorporate unit efficiency characteristics, water flow conditions and outage plans. Water flows and outage conditions are assessed and monitored on a monthly basis.

OPG's hydroelectric generating stations vary in age from 13 to 108 years, with an average age of over 72 years. Over 75 per cent of the hydroelectric generating capacity is over 50 years old. Due to the variability and age of some of the equipment and civil components, there is a risk that some facilities will require significant work and funding to sustain their reliability. OPG manages these reliability risks by conducting ongoing maintenance of critical components, engineering reviews, plant condition assessments, and inspections to identify future work necessary to sustain and, if necessary, upgrade the plant and its equipment. Over the next five years, OPG plans to continue its reinvestment in its hydroelectric assets to address issues associated with the age of the equipment and to improve the performance of the assets. The success of the program is monitored through the measurement of reliability improvements. OPG's hydroelectric assets continue to significantly outperform relevant North American benchmarks.

The hydroelectric business segment operates 238 dams across the province. To mitigate and manage the risks associated with the operation of these dams, OPG has a dam safety program that performs ongoing maintenance, upgrades and rehabilitation work. OPG also undertakes ongoing dam safety reviews and monitoring, and ad hoc peer reviews. Emergency preparedness and response plans have been established for all facilities to mitigate losses in the event of a dam failure or uncontrolled release of water.

*Unregulated – Fossil-Fuelled Segment Risks*

Electricity generation from fossil-fuelled generation units can be unfavourably affected by plant and equipment failures. OPG manages and mitigates these risks by performing ongoing maintenance and undertaking engineering reviews, condition assessments and critical reviews of maintenance processes. OPG uses the results of these reviews and assessments to implement changes to inspection, maintenance, and capital project programs. The performance of OPG's fossil-fuelled stations are measured by their availability to produce electricity when called upon. In the third quarter of 2007, OPG's fossil-fuelled generating stations have achieved significant reliability improvements while generating 8.2 TWh of electricity.

*Major Project Risk*

OPG is involved with several major development projects, including: the Niagara Tunnel, Lac Seul, Portlands Energy Centre, other projects supporting operating units, hydroelectric development projects, the potential refurbishment of existing nuclear stations, and the consideration of new nuclear units at OPG's Darlington nuclear generation site. There is a risk that OPG will have insufficient resources to implement several large projects concurrently. This risk is especially critical given the complexity, long project timelines, and inherent risks associated with these projects.

OPG has taken many steps to address the unique challenges relating to the various development projects. OPG utilizes Owner's Representative services to acquire the necessary technical expertise to monitor and control projects. Also, major projects have been contracted on a "design-build" basis, which provides OPG with greater cost certainty. In addition, certain projects have liquidated damages built into the contracts to mitigate late in-service by the respective contractor.

For nuclear related projects, OPG has established a new division to evaluate the viability of refurbishment of existing nuclear facilities in order to extend their life. The activities of this division include completing plant condition and environmental assessments, developing appropriate project infrastructures and confirming various industry regulatory requirements.

*Human Resources Risk*

OPG continues to face demographic risks and resourcing gaps. To address these risks, OPG has implemented plans and programs to meet current and future business needs for human resources and critical skills. Business leaders are actively involved in the review of workforce needs and plans to resource critical skills and jobs in their functional lines of business. Initiatives continue in support of OPG's employment brand, youth outreach and educational relations. In the third quarter of 2007, OPG launched its largest campus recruitment program to date, participating in career fairs and information sessions on campuses across Ontario and on the East Coast. In addition, OPG's commitment to building and strengthening internal capabilities was evidenced by the introduction of an integrated leadership competency model, focused efforts in terms of succession planning, and the introduction of a new supervisory training program. Since the launch of the supervisory training program, five sessions have been completed and in response to demand, additional sessions have been scheduled.

*Environmental Risk*

OPG's Environmental Policy commits OPG to meet all legal requirements and voluntary environmental commitments, integrate environmental factors into business planning and decision-making, and contribute to environmental protection, pollution prevention, and energy and resource use efficiency. This policy also commits OPG to maintain comprehensive environmental management systems ("EMSs") at its generating facilities consistent with the ISO 14001 standard.

OPG monitors emissions into the air and water and regularly reports the results to various regulators, including the Ministry of the Environment, Environment Canada and the Canadian Nuclear Safety Commission. The public also receives ongoing communications regarding OPG's environmental performance through community-based advisory groups, annual environmental reports, community newsletters, open houses and OPG's website. OPG has developed and implemented internal monitoring, assessment and reporting programs to manage environmental risks such as air and water emissions, discharges, spills, the treatment of radioactive emissions and radioactive wastes. OPG also continues to address historical land contamination through its voluntary land assessment and remediation program.

In the second quarter of 2007, the Federal Government introduced a plan to reduce both greenhouse gases and air pollutants, whereas the Ontario government introduced a plan to reduce greenhouse gases. OPG is assessing the implications of these announcements on its operations. In order to meet the proposed emission targets, there is a risk that OPG will be required to either reduce certain emissions or purchase offsets, which could have a material adverse impact to OPG.

## Financial Risks

*Commodity Price Risk*

Changes in the market price of electricity or of the fuels used to produce electricity can 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 economic opportunity to do so. To manage fuel risks, OPG has a fuel hedging program, which includes fixed price and indexed contracts for fossil and nuclear fuels, as well as commodity derivatives.

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

| | 2007 | 2008 | 2009 |
|---|---|---|---|
| Estimated generation output hedged [1] | 93% | 93% | 71% |
| Estimated fuel requirements hedged [2] | 99% | 92% | 75% |
| Estimated nitric oxide (NO) emission requirement hedged | 100% | 100% | 100% |
| Estimated $SO_2$ emission requirement hedged [3] | 100% | 100% | 100% |

1 Represents the portion of megawatt hours of expected future generation production, including power purchases, for which the Company has sales commitments and contracts including the obligations under regulated pricing commitments, agreements with the IESO, OPA auction sales and the revenue limit on OPG's non-prescribed assets.

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

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

*Trading Risk*

Open trading positions are subject to measurement against Value at Risk ("VaR") limits. For a given portfolio, VaR measures the possible future loss in terms of market value, which under normal market conditions will not be exceeded within a defined probability and time period. VaR utilization ranged between $0.4 million and $1.0 million during the three months ended September 30, 2007, compared to $2.0 million and $3.4 million during the three months ended September 30, 2006. VaR utilization is closely monitored in order to ensure compliance with approved limits.

*Liquidity Risk*

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

The recent market instabilities in the Canadian ABCP market impacts OPG's liquidity, since OPG's exposure to the matured and unpaid third-party ABCP was approximately $103 million as at September 30, 2007. Upon the expected payment of Skeena Capital Trust, OPG's holdings of third-party ABCP will be reduced to $58 million. OPG does not foresee any material adverse impact on its operations as a result of the current lack of liquidity in the third-party ABCP market.

A discussion of OPG's exposure to this liquidity risk is included in the *Recent Developments* section.

*Credit Risk*

OPG's credit risk exposure is comprised of two major components: the first is derived from its sales of electricity and the second is derived from its purchases of services and products. As the majority of OPG's sales are derived through the IESO administered spot market, OPG management accepts this credit risk due to the IESO's primary role in the Ontario electricity market. This confidence is based on the IESO's own credit risk management policies and practices, which require all spot market participants to meet specific standards for creditworthiness. Additionally, in the event of a participant default, the loss is shared on a pro-rata basis among all participants thus reducing the specific exposure to OPG.

The following table provides information on credit risk from energy sales and trading activities as at September 30, 2007:

| | | | Potential Exposure for Largest Counterparties | |
|---|---|---|---|---|
| **Credit Rating [1]** | **Number of Counterparties [2]** | **Potential Exposure [3]** | **Number of Counterparties** | **Counterparty Exposure** |
| | | *(millions of dollars)* | | *(millions of dollars)* |
| Investment grade | **165** | **98** | **5** | **80** |
| Below investment grade | **43** | **35** | **5** | **25** |
| IESO [4] | **1** | **391** | **1** | **391** |
| Total | **209** | **524** | **11** | **496** |

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's counterparties are defined by each master agreement.
3 Potential exposure is OPG's assessment of maximum exposure over the life of each transaction at 95 per cent confidence.
4 Credit exposure to the IESO peaked at $883 million during the nine months ended September 30, 2007 and at $1,029 million during the year ended December 31, 2006.

OPG's second element of credit risk relates to the exposures created by companies ("counterparties") who are contracted to provide services or products. OPG manages this risk using a credit risk management function that evaluates all major counterparties and provides ongoing input to business units who acquire these services.

**Strategic Risks**

*Regulatory Risk*

Effective April 1, 2005, OPG receives regulated prices for electricity generated from most of its baseload hydroelectric facilities and all of the nuclear facilities that it operates. These prices are expected to remain in effect until at least March 31, 2008. If there are changes to the fundamental assumptions on which these regulated prices were developed, the Province may amend them.

Effective some time after March 31, 2008, the OEB is expected to establish new regulated prices for electricity generated by OPG's regulated facilities. The process of setting new regulated prices is inherently uncertain. The new prices established by the OEB may not provide for recovery of all of OPG's costs, or may not provide an appropriate rate of return. Despite the fact that some costs may not be included within the new prices, these expenditures may still be necessary to maintain the reliability and safety of OPG's regulated generating assets.

Following a consultation process in 2006, the OEB concluded that a limited cost of service form of regulation for OPG is appropriate for establishing prices to be effective on or after April 1, 2008. Under this method, new prices are based on the total revenue requirement and forecast production. The OEB has stated that its first order for new prices is expected to be in effect until December 31, 2009. OPG expects to file an application for new prices in November 2007. The prices ultimately established by the

OEB may have significant implications on OPG's financial performance, operating plans and prospects. A delay in the effective date of new prices beyond April 1, 2008 may result in a continuation of current prices. To the extent that these prices do not reflect current costs and operating plans, this could negatively impact the Company's financial performance.

OPG has recorded certain regulatory assets and liabilities pursuant to the *Electricity Restructuring Act, 2004* (Ontario), which it expects to recover or refund through future regulated prices to be established by the OEB. In accordance with the regulation, the accuracy and prudence of certain of these balances must be demonstrated to the OEB as part of the process to establish new regulated prices. In the event that some of the amounts recorded as regulatory assets or liabilities are disallowed by the OEB, amounts disallowed will be reflected in the results of operations in the period that the OEB decision occurs.

## CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

During the most recent interim period, there have been no changes in the Company's policies and procedures and other processes that comprise its internal control over financial reporting, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

## QUARTERLY FINANCIAL HIGHLIGHTS

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

| *(millions of dollars)* | September 30 2007 | June 30 2007 | March 31 2007 | December 31 2006 |
|---|---|---|---|---|
| Revenue after revenue limit rebate | **1,421** | 1,373 | 1,524 | 1,276 |
| Net income (loss) | **113** | 125 | 171 | (19) |
| Net income (loss) per share | **$0.44** | $0.48 | $0.67 | $(0.08) |

| *(millions of dollars)* | September 30 2006 | June 30 2006 | March 31 2006 | December 31 2005 |
|---|---|---|---|---|
| Revenue after revenue limit rebate | 1,435 | 1,345 | 1,508 | 1,496 |
| Net income | 167 | 143 | 199 | 160 |
| Net income per share | $0.65 | $0.56 | $0.78 | $0.62 |

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.

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

- Write-off of $35 million of excess inventory as a result of not returning Pickering A generating station Units 2 and 3 to service recorded in the fourth quarter of 2005;
- Higher depreciation expense related to the return to service of Unit 1 at the Pickering A generating station in the fourth quarter of 2005;
- Decrease in depreciation expense primarily due to the extension of service lives, for accounting purposes, of the Nanticoke generating station, Pickering B generating station and Unit 4 of the Pickering A generating station beginning in the first quarter of 2006;

- Higher pension and OPEB costs during 2006 and 2007 compared to 2005 mainly due to changes in economic assumptions used to measure the costs;
- Write-off of $13 million for costs incurred on the Thunder Bay conversion project due to a Shareholder Declaration that effectively cancelled the project during the second quarter of 2006;
- Decrease in depreciation expense primarily due to extension of the service life, for accounting purposes, of all coal-fired generating stations to December 31, 2012, beginning in the third quarter of 2006;
- Impairment loss on the Thunder Bay and Atikokan coal-fired generating stations of $22 million, reflecting the carrying value of the stations, during the fourth quarter of 2006;
- Decrease in gross margin from electricity sales primarily due to lower generation from OPG's nuclear generating stations, partially offset by increased generation from higher marginal cost fossil-fuelled generating stations in the first quarter of 2007;
- Higher OM&A expense in 2007 primarily due to higher outage and other maintenance expenditures at OPG's nuclear and fossil-fuelled generating stations, and expenses related to past grievances by First Nations; and
- Higher earnings from the Nuclear Funds during the second quarter of 2007 primarily due to a higher Ontario CPI during the second quarter of 2007, which impacted the guaranteed return on the Used Fuel Fund. In addition, the increase in earnings also reflected a reimbursement from the Nuclear Funds for expenditures related to the safe storage of Pickering A Units 2 and 3.

### SUPPLEMENTAL EARNINGS MEASURES

In addition to providing net income in accordance with Canadian GAAP, OPG's MD&A, unaudited interim consolidated financial statements as at and for the three and nine months ended September 30, 2007 and 2006 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 rebate and fuel expense.

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


| | | |
|---|---|---|
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## INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

| *(millions of dollars except where noted)* | **Three Months Ended September 30** | | **Nine Months Ended September 30** | |
|---|---|---|---|---|
| | **2007** | **2006** | **2007** | **2006** |
| **Revenue** | | | | |
| Revenue before revenue limit rebate | **1,481** | 1,494 | **4,494** | 4,436 |
| Revenue limit rebate *(Note 14)* | **(60)** | (59) | **(176)** | (148) |
| | **1,421** | 1,435 | **4,318** | 4,288 |
| Fuel expense | **336** | 310 | **962** | 831 |
| **Gross margin** | **1,085** | 1,125 | **3,356** | 3,457 |
| **Expenses** | | | | |
| Operations, maintenance and administration | **689** | 628 | **2,159** | 1,946 |
| Depreciation and amortization *(Note 5)* | **168** | 154 | **519** | 525 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **127** | 125 | **381** | 375 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(92)** | (82) | **(392)** | (274) |
| Property and capital taxes | **17** | 35 | **66** | 82 |
| | **909** | 860 | **2,733** | 2,654 |
| **Income before interest and income taxes** | **176** | 265 | **623** | 803 |
| Net interest expense | **37** | 47 | **102** | 145 |
| **Income before income taxes** | **139** | 218 | **521** | 658 |
| Income tax expenses | | | | |
| Current | **21** | 47 | **98** | 93 |
| Future *(Note 10)* | **5** | 4 | **14** | 56 |
| | **26** | 51 | **112** | 149 |
| **Net income** | **113** | 167 | **409** | 509 |
| **Basic and diluted income per common share** *(dollars)* | **0.44** | 0.65 | **1.60** | 1.99 |
| **Common shares outstanding** *(millions)* | **256.3** | 256.3 | **256.3** | 256.3 |

*See accompanying notes to the interim consolidated financial statements*

## INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

| *(millions of dollars)* | **Three Months Ended September 30 2007** | **Three Months Ended September 30 2006** | **Nine Months Ended September 30 2007** | **Nine Months Ended September 30 2006** |
|---|---|---|---|---|
| **Operating activities** | | | | |
| Net income | **113** | 167 | **409** | 509 |
| Adjust for non-cash items: | | | | |
| Depreciation and amortization *(Note 5)* | **168** | 154 | **519** | 525 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **127** | 125 | **381** | 375 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(92)** | (82) | **(392)** | (274) |
| Pension cost *(Note 11)* | **61** | 54 | **182** | 163 |
| Other post employment benefits and supplementary pension plans *(Note 11)* | **64** | 67 | **186** | 194 |
| Future income taxes *(Note 10)* | **5** | 4 | **14** | 56 |
| Transition rate option contracts | **-** | - | **-** | (13) |
| Mark-to-market on derivative instruments | **(1)** | (2) | **10** | (19) |
| Provision for used nuclear fuel | **7** | 7 | **22** | 23 |
| Regulatory assets and liabilities | **(9)** | (6) | **(6)** | (2) |
| Provision for other liabilities | **1** | 1 | **47** | 8 |
| Other | **17** | 2 | **6** | 4 |
| | **461** | 491 | **1,378** | 1,549 |
| Contributions to nuclear fixed asset removal and nuclear waste management funds | **(113)** | (113) | **(340)** | (340) |
| Expenditures on fixed asset removal and nuclear waste management | **(48)** | (42) | **(148)** | (112) |
| Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management | **16** | 3 | **102** | 14 |
| Contributions to pension fund | **(66)** | (65) | **(198)** | (195) |
| Expenditures on other post employment benefits and supplementary pension plans | **(19)** | (18) | **(53)** | (49) |
| Revenue limit rebate | **(101)** | (63) | **(149)** | (802) |
| Expenditure on restructuring | **-** | (1) | **(2)** | (7) |
| Net changes to other long-term assets and liabilities | **(18)** | (28) | **(37)** | (92) |
| Changes in non-cash working capital balances *(Note 16)* | **136** | 143 | **170** | 340 |
| **Cash flow provided by operating activities** | **248** | 307 | **723** | 306 |
| **Investing activities** | | | | |
| Increase in regulatory assets *(Note 6)* | **(10)** | (1) | **(48)** | (13) |
| Investment in fixed assets | **(179)** | (188) | **(476)** | (422) |
| Net proceeds from sale of long-term investments | **-** | (2) | **-** | - |
| Cash and cash equivalents transferred to short-term investments (*Note 3)* | **(103)** | - | **(103)** | - |
| **Cash flow used in investing activities** | **(292)** | (191) | **(627)** | (435) |
| **Financing activities** | | | | |
| Issuance of long-term debt *(Note 8)* | **240** | - | **450** | - |
| Repayment of long-term debt *(Note 8)* | **(202)** | (301) | **(405)** | (604) |
| Net decrease in short-term notes *(Note 7)* | **-** | - | **(15)** | - |
| **Cash flow provided by (used in) financing activities** | **38** | (301) | **30** | (604) |
| **Net increase (decrease) in cash and cash equivalents** | **(6)** | (185) | **126** | (733) |
| **Cash and cash equivalents, beginning of period** | **138** | 360 | **6** | 908 |
| **Cash and cash equivalents, end of period** | **132** | 175 | **132** | 175 |

*See accompanying notes to the interim consolidated financial statements*

## INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

| **As at**<br>*(millions of dollars)* | **September 30 2007** | **December 31 2006** |
|---|---|---|
| **Assets** | | |
| **Current assets** | | |
| Cash and cash equivalents | **132** | 6 |
| Short-term investments (Note 3) | **103** | - |
| Accounts receivable *(Note 4)* | **230** | 230 |
| Prepaid expenses | **59** | 26 |
| Fuel inventory *(Note 15)* | **508** | 669 |
| Materials and supplies *(Note 15)* | **119** | 112 |
| | **1,151** | 1,043 |
| **Fixed assets** *(Note 15)* | | |
| Property, plant and equipment | **17,599** | 17,136 |
| Less: accumulated depreciation | **4,838** | 4,375 |
| | **12,761** | 12,761 |
| **Other long-term assets** | | |
| Deferred pension asset | **722** | 706 |
| Nuclear fixed asset removal and nuclear waste management funds *(Note 9)* | **8,743** | 7,594 |
| Long-term materials and supplies | **343** | 326 |
| Regulatory assets *(Note 6)* | **324** | 251 |
| Long-term accounts receivable and other assets | **124** | 69 |
| | **10,256** | 8,946 |
| | **24,168** | 22,750 |

*See accompanying notes to the interim consolidated financial statements*

## INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

| **As at**<br>*(millions of dollars)* | **September 30 2007** | **December 31 2006** |
|---|---|---|
| **Liabilities** | | |
| **Current liabilities** | | |
| Accounts payable and accrued charges | **824** | 989 |
| Revenue limit rebate payable *(Note 14)* | **67** | 40 |
| Short-term notes payable *(Note 7)* | **-** | 15 |
| Long-term debt due within one year *(Note 8)* | **406** | 406 |
| Future income taxes *(Note 10)* | **5** | 3 |
| Deferred revenue due within one year | **12** | 12 |
| Income and capital taxes payable | **178** | 128 |
| | **1,492** | 1,593 |
| **Long-term debt** *(Note 8)* | **2,998** | 2,953 |
| **Other long-term liabilities** | | |
| Fixed asset removal and nuclear waste management *(Note 9)* | **10,857** | 10,520 |
| Other post employment benefits and supplementary pension plans | **1,529** | 1,396 |
| Long-term accounts payable and accrued charges | **184** | 150 |
| Deferred revenue | **123** | 132 |
| Future income taxes *(Note 10)* | **272** | 246 |
| Regulatory liabilities *(Note 6)* | **10** | 11 |
| | **12,975** | 12,455 |
| **Shareholder's equity** | | |
| Common shares | **5,126** | 5,126 |
| Retained earnings *(Note 2)* | **1,545** | 623 |
| Accumulated other comprehensive income | **32** | - |
| | **6,703** | 5,749 |
| | **24,168** | 22,750 |

Commitments and Contingencies (Notes 6, 7, 8, 9, 12 and 13)

*See accompanying notes to the interim consolidated financial statements*

## INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY (UNAUDITED)

| **Nine Months Ended September 30**<br>*(millions of dollars)* | **2007** | **2006** |
|---|---|---|
| **Common shares** | **5,126** | 5,126 |
| **Retained earnings** | | |
| Balance at beginning of period | **623** | 261 |
| Transition adjustment on adoption of financial instruments accounting standards *(Note 2)* | **513** | - |
| Net income | **409** | 509 |
| Dividends | **-** | (128) |
| Balance at end of period | **1,545** | 642 |
| **Accumulated other comprehensive income, net of income taxes** | | |
| Balance at beginning of period | **-** | |
| Transition adjustment on adoption of financial instruments accounting standards *(Note 2)* | **21** | |
| Other comprehensive income for the period | **11** | |
| Balance at end of period | **32** | |
| **Total shareholder's equity at end of period** | **6,703** | 5,768 |

## INTERIM CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME (UNAUDITED)

| *(millions of dollars)* | **Three Months Ended September 30 2007** | **Nine Months Ended September 30 2007** |
|---|---|---|
| **Net income** | **113** | 409 |
| **Other comprehensive income, net of income tax** | | |
| Net (loss) gain on derivatives designated as cash flow hedges[1] | **(13)** | 24 |
| Reclassification to income of gains on derivatives designated as cash flow hedges[2] | **(5)** | (13) |
| Other comprehensive (loss) income for the period | **(18)** | 11 |
| **Comprehensive income** | **95** | 420 |

[1] Net of income tax of nil and $5 million for the three and nine months ended September 30, 2007, respectively.

[2] Net of income tax benefit of $3 million and $7 million for the three and nine months ended September 30, 2007, respectively.

*See accompanying notes to the interim consolidated financial statements*

## NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2007 AND 2006 (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 consolidated 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, 2006.

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, revenue and expenses, and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

Certain of the 2006 comparative amounts have been reclassified from financial statements previously presented to conform to the 2007 interim consolidated financial statement presentation.

The interim 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* (Ontario) received Royal Assent. A regulation made pursuant to that statute by the Province of Ontario (the "Province") in February 2005 provides that OPG receives regulated prices beginning April 1, 2005 for electricity generated from most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that it operates. This includes electricity generated from 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 facilities. The regulation was amended in February 2007. The amendment clarified certain aspects of the regulation and directed OPG to establish a deferral account related to certain changes in its liabilities for nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management.

OPG's regulated prices were established by the Province based on a forecast of production volumes and total operating costs, and a return on rate base, which assumed an average five per cent rate of return on equity. Rate base is a regulatory construct that represents the average net level of investment in regulated fixed assets and an allowance for working capital. The initial prices took effect April 1, 2005, and are expected to remain in effect until at least March 31, 2008, at which time the Ontario Energy Board (the "OEB") will assume responsibility for establishing new regulated 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 interim consolidated financial statements as regulatory assets and liabilities. When the regulation provides assurance that incurred expenses will be recovered in the future, then OPG may defer those expenses and report them as a regulatory asset. If current recovery is provided for expenses 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 regulated prices, then OPG recognizes a regulatory asset or liability, respectively. The measurement of such regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of the regulation. See Notes 6 and 10 to the unaudited interim consolidated financial statements for additional disclosure related to rate regulated accounting.

**Changes in Accounting Policies and Estimates**

On January 1, 2007, OPG adopted three new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Handbook Section 1530, *Comprehensive Income*; Handbook Section 3855, *Financial Instruments – Recognition and Measurement*; and Handbook Section 3865, *Hedges*. OPG adopted these standards prospectively, and, as such, comparative amounts for prior periods have not been restated.

*Comprehensive Income*

As a result of adopting these standards, a new category, accumulated other comprehensive income, was added to shareholder's equity in the interim consolidated balance sheets. Comprehensive income consists of net income and other comprehensive income. This category includes changes in the fair value of the effective portion of cash flow hedging instruments. Amounts are recorded in other comprehensive income until the criteria for recognition in the interim consolidated statements of income are met.

*Financial Instruments – Recognition and Measurement*

Under the new standard, for accounting purposes, financial assets are classified as one of the following: held-to-maturity, loans and receivables, held-for-trading or available-for-sale, and financial liabilities are classified as held-for-trading or other than held-for-trading. Financial assets and liabilities held-for-trading are 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, are measured at amortized cost. Financial assets purchased and sold, where the contract requires the asset to be delivered within an established timeframe, are recognized on a trade-date basis. 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 interim consolidated balance sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

The new standard permits designation of any financial instrument as held-for-trading (the fair value option) upon initial recognition. This designation by OPG requires that the financial instrument be reliably measurable, and eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets or liabilities.

*Hedges*

The 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 cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income. The ineffective portion is recognized in net income. The amounts recognized in accumulated other comprehensive income are reclassified to net income in the periods in which net income is affected by the variability in the cash flows of the hedged item.

*Impact of Adoption*

Upon adoption of the financial instruments accounting standards, the assets in the Used Fuel Segregated Fund ("Used Fuel Fund") and the Decommissioning Segregated Fund ("Decommissioning Fund") (together the "Nuclear Funds") that were carried at amortized cost until the end of 2006, were classified as held-for-trading and reported at fair value. The transition adjustment related to the change in accounting for the Nuclear Funds was recognized in the opening balance of retained earnings at January 1, 2007. The transition adjustment for embedded derivatives within long-term contracts was also recognized in the opening balance of retained earnings at January 1, 2007. Prior to January 1, 2007, OPG disclosed the fair value of securities in the Nuclear Funds based on the closing price of the securities. Starting January 1, 2007, OPG applied bid pricing to determine the fair value of the securities. As a result, the fair value of the Nuclear Funds based on bid pricing is lower than that reported as at December 31, 2006 in Note 9 of the audited consolidated financial statements. The change in pricing methodology does not have any impact to the overall balance on the interim consolidated balance sheets since the reduction in fair value is offset by the corresponding change in the due to Province balance.

The fair values of hedging instruments designated as cash flow hedges were recognized in the opening accumulated other comprehensive income on a net of tax basis. The fair values of these hedges are disclosed in Note 12 to the unaudited interim consolidated financial statements.

The transition amounts that were recorded in the opening retained earnings or in the opening accumulated other comprehensive income balance on January 1, 2007 were as follows:

| | **At Cost** | **At Fair Value** | **Transition Amounts – January 1, 2007** | |
|---|---|---|---|---|
| *(millions of dollars)* | **December 31 2006** | **January 1 2007** | **Opening Retained Earnings** | **Opening Accumulated Other Comprehensive Income** |
| Nuclear Funds balance | 7,694 | 9,041 | 1,347 | - |
| Due to Province | (100) | (928) | (828) | - |
| | 7,594 | 8,113 | 519 | - |
| Accounts receivable and other assets | 325 | 372 | - | 47 |
| Accounts payable and accrued charges | (989) | (1,005) | (6) | (10) |
| Net future income tax liability | (249) | (265) | - | (16) |
| Transition adjustments | | | 513 | 21 |

**Future Changes in Accounting Policies**

*Capital Disclosures*

The CICA issued an accounting standard, Section 1535, *Capital Disclosures*, which requires the disclosure of both qualitative and quantitative information that enables users of financial statements to evaluate the entity's objectives, policies and processes for managing capital. The standards also require companies to disclose if the company has complied with any capital requirements, and, if it has not complied, the consequences of such non-compliance. This new accounting standard will be effective for the Company beginning January 1, 2008. OPG is evaluating the impact of this new standard on its consolidated financial statements.

*Financial Instruments – Disclosure and Presentation*

OPG will be required to adopt Section 3862, *Financial Instruments – Disclosures*, and Section 3863, *Financial Instruments – Presentation*. These standards were issued in December 2006 and will replace Section 3861, *Financial Instruments – Disclosure and Presentation*. The new disclosure standard increases the emphasis on the risk associated with both recognized and unrecognized financial instruments and how those risks are managed. The new presentation standard carries forward the former presentation requirements under the existing Section 3861. These new accounting standards will be effective for OPG beginning January 1, 2008. OPG is assessing the impact of the new standards on its consolidated financial statements.

*Inventories*

The CICA issued a new accounting standard, Section 3031, *Inventories*, in March 2007, which is based on International Accounting Standard ("IAS") 2. The new section replaced the existing Section 3030, *Inventories*. Under the new section, inventories are required to be measured at the "lower of cost and net realizable value", which is different from the existing guidance of the "lower of cost and market". The new section also allows the reversal of any write-downs previously recognized. Further, due to the changes in the section and the consequential amendments, some of OPG's critical spare parts currently reported as materials and supplies on OPG's consolidated balance sheet may be accounted for in the future as property, plant and equipment. The new accounting standard and any consequential amendments will be effective for OPG beginning January 1, 2008. OPG is in the process of assessing the impact of the new standard.

## 3. SHORT-TERM INVESTMENTS

In August 2007, a number of Canadian third-party Trusts, as issuers of Asset-Backed Commercial Paper ("ABCP") experienced difficulty in accessing the liquidity required to repay maturing ABCP debt. OPG held temporary investments in the amount of $103 million in ABCP issued by a number of these third-party Trusts. On September 30, 2007, all of the notes had matured and remain unpaid. The ABCP notes held by OPG continue to be rated by Dominion Bond Rating Service ("DBRS") as R1- (high), the highest rating issued by DBRS.

Of the $103 million of third-party ABCP held on September 30, 2007, $45 million consisted of notes held with Skeena Capital Trust ("Skeena"). On October 16, 2007, investors holding notes of Skeena were notified that they would receive the full value of their investment as a result of a restructuring plan where all $2.1 billion of notes outstanding would be redeemed at par, plus a portion of the accrued interest. Funding for this restructuring will be provided through the issuance of long-term floating rate notes issued by a new trust established for this purpose by new investors. OPG elected not to purchase the floating rate notes of the new trust, and therefore, expects to receive full value of the notes currently held in Skeena. The proposed restructuring, including the redemption of the notes, is subject to final documentation. Investors were advised that the transaction would be completed by, or shortly after, the end of October 2007. OPG expects that final documentation and settlement is forthcoming. Upon payment of the Skeena notes of $45 million, OPG's holdings of third-party ABCP will be reduced to $58 million.

OPG has classified the third-party ABCP as temporary investments. The fair value of the assets underlying third-party ABCP and the outcome of any restructuring proposal could give rise to a charge to OPG's earnings. OPG has not recorded any write-down related to its third-party ABCP temporary investments in the third quarter of 2007 based on the expected immateriality of any such charge or write-down, the measurement uncertainty related to this matter, and the expectation that additional information will be available by mid-December, the target date established by the Investors Committee for completing a review of the affected Trusts and providing guidance to noteholders on the proposed restructuring. OPG has sufficient credit facilities to satisfy its financial obligations as they come due and does not expect there will be a material adverse impact on its business as a result of this current third-party ABCP liquidity issue.

## 4. SALE OF ACCOUNTS RECEIVABLE

In October 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 September 30, 2007, the Company has recognized pre-tax charges of $4 million (three months ended September 30, 2006 – $4 million) on such sales at an average cost of funds of 5.2 per cent (three months ended September 30, 2006 – 4.6 per cent). For the nine months ended September 30, 2007, the Company has recognized pre-tax charges of $11 million (nine months ended September 30, 2006 – $10 million) on such sales at an average cost of funds of 4.9 per cent (nine months ended September 30, 2006 – 4.4 per cent). As at September 30, 2007, OPG had sold receivables of $300 million (December 31, 2006 – $300 million) from its total portfolio of $401 million (December 31, 2006 – $392 million).

## 5. FIXED ASSETS, DEPRECIATION AND AMORTIZATION

Depreciation and amortization expense for the three and nine months ended September 30, 2007 and 2006 consists of the following:

| | **Three Months Ended September 30** | | **Nine Months Ended September 30** | |
|---|---|---|---|---|
| *(millions of dollars)* | **2007** | **2006** | **2007** | **2006** |
| Depreciation | **144** | 146 | **435** | 500 |
| Amortization of deferred Pickering A return to service costs *(Note 6)* | **20** | 6 | **76** | 21 |
| Nuclear waste management costs | **4** | 2 | **8** | 4 |
| | **168** | 154 | **519** | 525 |

Interest capitalized to construction in progress at six per cent during the three and nine months ended September 30, 2007 (three and nine months ended September 30, 2006 – six per cent) was $11 million and $29 million, respectively (three and nine months ended September 30, 2006 – $5 million and $13 million, respectively).

## 6. REGULATORY ASSETS AND LIABILITIES AND SUMMARY OF RATE REGULATED ACCOUNTING

The regulatory assets and liabilities as at September 30, 2007 and December 31, 2006 are as follows:

| *(millions of dollars)* | **September 30 2007** | **December 31 2006** |
|---|---|---|
| Regulatory assets | | |
| Pickering A return to service costs | **200** | 249 |
| Nuclear liabilities deferral account | **97** | - |
| Nuclear generation development costs | **20** | - |
| Hydroelectric production variance | **2** | - |
| Ancillary services revenue variance | **3** | - |
| Transmission outages and transmission restrictions variance | **2** | 2 |
| Total regulatory assets | **324** | 251 |
| Regulatory liabilities | | |
| Hydroelectric production variance | **-** | 4 |
| Other | **10** | 7 |
| Total regulatory liabilities | **10** | 11 |

The changes in the regulatory assets and liabilities for the nine months ended September 30, 2007 and the year ended December 31, 2006 are as follows:

| *(millions of dollars)* | **Pickering A Return to Service Costs** | **Nuclear Liabilities Deferral Account** | **Nuclear Generation Development Costs** | **Transmission Outages and Transmission Restrictions Variance** | **Hydro-electric Production Variance** | **Ancillary Services Revenue Variance** | **Other** |
|---|---|---|---|---|---|---|---|
| Regulatory assets (liabilities), January 1, 2006 | 261 | - | - | - | (4) | 5 | (8) |
| Change during the year | 13 | - | - | 2 | - | (5) | 1 |
| Amortization during the year | (25) | - | - | - | - | - | - |
| Regulatory assets (liabilities), December 31, 2006 | 249 | - | - | 2 | (4) | - | (7) |
| Change during the period | 27 | 97 | 20 | - | 6 | 3 | (3) |
| Amortization during the period | (76) | - | - | - | - | - | - |
| Regulatory assets (liabilities), September 30, 2007 | **200** | **97** | **20** | **2** | **2** | **3** | **(10)** |

### Pickering A Return to Service Costs

Effective January 1, 2005, in accordance with a regulation made under the *Electricity Restructuring Act, 2004* (Ontario), OPG was required to establish a deferral account in connection with non-capital costs incurred on or after January 1, 2005 that were associated with the planned return to service of all units at the Pickering A nuclear generating station. The regulation, as amended in February 2007, also requires OPG to record interest at an annual rate of six per cent on the balance in the deferral account. As at September 30, 2007, the balance in the deferral account was $200 million, consisting of non-capital costs of $232 million relating to Unit 1 and $19 million relating to Units 2 and 3, $20 million of general return to service non-capital costs and interest of $34 million, net of the accumulated amortization of $105 million. As at December 31, 2006, the balance in the deferral account was $249 million, consisting of non-capital costs of $232 million relating to Unit 1 and $19 million relating to Units 2 and 3, $20 million of general return to service non-capital costs and interest of $7 million, net of the accumulated amortization of $29 million.

There were no operations, maintenance and administration ("OM&A") costs charged to the deferral account during the three and nine months ended September 30, 2007. During the three months ending September 30, 2006 there were no charges deferred and for the nine months ended September 30, 2006, OM&A expenses of $12 million were charged to the deferral account. Had OPG not charged these costs to the deferral account, OM&A expenses would have increased by $12 million for the nine months ended September 30, 2006.

During the three and nine months ended September 30, 2007, OPG deferred additional interest related to the Pickering A return to service deferral account of $3 million and $27 million, respectively. Had OPG not applied interest to this account, the net interest expense would have increased by $3 million and $27 million for the three and nine months ended September 30, 2007, respectively (three and nine months ended September 30, 2006 – nil).

The costs accumulated in the deferral account are charged to operations in accordance with the terms of the regulation. 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. Had OPG not amortized the costs in the deferral account, depreciation and amortization expense for the three and nine months ended September 30, 2007 would have been reduced by $20 million and $76 million, respectively (three and nine months ended September 30, 2006 – $6 million and $21 million, respectively).

**Nuclear Liabilities Deferral Account**

In February 2007, the Province amended a regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) to direct OPG to establish a deferral account in connection with certain changes to its liabilities for nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management. The deferral account represents the revenue requirement impact associated with the changes in the nuclear liabilities arising from an approved reference plan, approved after April 1, 2005, as reflected in OPG's audited consolidated financial statements. Revenue requirement is a regulatory construct, which represents all allowed costs and a return on rate base at a rate of return that the regulator determines to be appropriate. The regulation also requires OPG to record interest at an annual rate of six per cent on the balance in the deferral account.

On December 31, 2006, OPG recorded an increase in its nuclear liabilities of $1,386 million arising from the approved reference plan in accordance with the terms of the Ontario Nuclear Funds Agreement ("2006 Approved Reference Plan"). Commencing January 1, 2007 and up to the effective date of the OEB's first order establishing regulated prices, which is expected to be after March 31, 2008, OPG will record a regulatory asset associated with the increase in the nuclear liabilities arising from the 2006 Approved Reference Plan.

The OEB is directed by the regulation to ensure that OPG recovers the balance recorded in the deferral account on a straight-line basis over a period not to exceed three years, to the extent that the OEB is satisfied that the revenue requirement impacts are accurately recorded.

As at September 30, 2007, the following items have been recorded as components of the regulatory asset relating to the increase in the nuclear liabilities arising from the 2006 Approved Reference Plan:

| *(millions of dollars)* | **September 30 2007** |
|---|---|
| Return on rate base | 56 |
| Depreciation expense | 40 |
| Fuel expense | (4) |
| Capital tax | 3 |
| Interest expense | 2 |
| | 97 |

The return on rate base component of $18 million and $56 million was recorded as a reduction to the accretion on fixed asset removal and nuclear waste management liabilities expense for the three and nine months ended September 30, 2007, respectively.

Had OPG not established the deferral account as required by the regulation, for the three months ended September 30, 2007, accretion expense would have increased by $18 million, depreciation expense would have increased by $12 million, property and capital taxes expense would have been higher by $1 million, net interest expense would have increased by $1 million, and fuel expense would have been lower by $1 million. For the nine months ended September 30, 2007, accretion expense would have increased by $56 million, depreciation expense would have increased by $40 million, property and capital taxes expense would have been higher by $3 million, net interest expense would have increased by $2 million, and fuel expense would have been lower by $4 million.

The regulation also provides for the recovery of an amount relating to additional income taxes that OPG will be subject to as a result of recovering the regulatory asset through future regulated prices charged to customers. Since OPG has not yet incurred a related income tax expense, no amounts related to income taxes have been recorded as part of the regulatory asset.

**Nuclear Generation Development Costs**

The amendment to the regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) made in February 2007 clarified that the OEB must ensure that OPG recovers, through future regulated prices, all capital and non-capital costs incurred in order to increase the output of, refurbish or add operating capacity to a regulated facility, if these costs are either within budgets approved by OPG's Board of Directors prior to the OEB's first order establishing regulated prices or if the OEB is satisfied that these costs were prudently incurred. As a result of the amendment, OPG has recorded a regulatory asset of $6 million and $20 million during the three and nine months ended September 30, 2007, respectively, which represents non-capital costs incurred since April 1, 2005 for its nuclear generation development initiatives.

Had OPG not recorded the above costs as a regulatory asset, OM&A expenses would have increased by $6 million and $20 million for the three and nine months ended September 30, 2007, respectively.

**Variance Accounts and Other Regulatory Balances**

Effective April 1, 2005, in accordance with a regulation made under the *Electricity Restructuring Act, 2004* (Ontario), OPG was directed to establish variance accounts for capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecast information provided to the Province for the purposes of establishing regulated prices. Variance accounts have been established for differences in hydroelectric electricity production due to differences between forecast and actual water conditions, unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear facilities, changes to revenues for ancillary services from the regulated facilities, acts of God (including severe weather events), and transmission outages and transmission restrictions.

OPG recorded an increase in revenue during the three months ended September 30, 2007 of $2 million, reflecting ancillary services revenue that was unfavourable compared to the forecast provided to the Province for the purposes of establishing regulated prices. For the nine months ended September 30, 2007, OPG recorded an increase in revenue of $3 million, reflecting ancillary services revenue that was unfavourable compared to the forecast. For the three and nine months ended September 30, 2007, OPG recorded an increase in revenue of $7 million and $6 million, respectively, as a result of actual water conditions that were unfavourable to those forecast.

OPG recorded an increase in revenue during the three months ending September 30, 2006 of $4 million reflecting ancillary services revenue that was unfavourable compared to the forecast provided to the Province and a reduction in income of $6 million for the nine months ended September 30, 2006, reflecting ancillary services revenue that was favourable compared to the forecast provided to the Province for the purposes of establishing regulated prices. For the three and nine months ended September 30, 2006, OPG recorded an increase in revenue of $1 million and $8 million, respectively, for each period as a result of lower actual water conditions compared to those forecasted.

The OEB is directed by the regulation to ensure recovery of amounts recorded in the variance accounts to the extent that the OEB is satisfied that revenues recorded in the accounts were earned or foregone, that costs recorded in the accounts were prudently incurred, and that both revenues and costs are accurately recorded. Any balances approved by the OEB will be amortized over a period not to exceed three years. The amortization will commence when OPG starts to recover or return the balances through new prices that will be set by the OEB. Any balances in the accounts disallowed by the OEB will be reflected in the results of operations in the period that the OEB decision occurs.

The other regulatory liability consists of a portion of non-regulated revenue earned by OPG's regulated assets and interest on the account balance, which may result in a reduction of future regulated prices to be established by the OEB. OPG recorded an additional liability of $1 million. During the three months ended September 30, 2007 (three months ended September 30, 2006 – an asset of $ 1 million). For the nine months ended September 30, 2007, OPG recorded an additional liability of $2 million, including $1 million of interest expense (nine months ended September 30, 2006 – an asset of $1 million).

Had OPG not accounted for the variance accounts and other regulatory balances as regulatory assets and liabilities, revenue for the three months ended September 30, 2007 would have been lower by $8 million (three months ended September 30, 2006 – lower by $6 million). For the nine months ended September 30, 2007, revenue would have been lower by $6 million (nine months ended September 30, 2006 – lower by $2 million).

Had OPG not accounted for the variance accounts and other regulatory balances as regulatory assets and liabilities, interest expense for the three months ended September 30, 2007 (and three months ended September 30, 2006) would have remained the same. For the nine months ended September 30, 2007, interest expense would have decreased by $1 million (nine months ended September 30, 2006 – nil).

**Summary of Rate Regulated Accounting**

The following tables summarize the impact of applying rate regulated accounting for selected income statement information:

| | Three Months Ended September 30, 2007 | | | Three Months Ended September 30, 2006 | | |
|---|---|---|---|---|---|---|
| *(millions of dollars)* | As Stated | Impact of Rate Regulated Accounting | Financial Statements without Rate Regulated Accounting | As Stated | Impact of Rate Regulated Accounting | Financial Statements without Rate Regulated Accounting |
| Revenue | **1,421** | **10** | **1,431** | 1,435 | 11 | 1,446 |
| Fuel expense | **336** | **(1)** | **335** | 310 | - | 310 |
| Operations, maintenance, and administration | **689** | **6** | **695** | 628 | 1 | 629 |
| Depreciation and amortization | **168** | **(8)** | **160** | 154 | (6) | 148 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **127** | **18** | **145** | 125 | - | 125 |
| Property and capital taxes | **17** | **1** | **18** | 35 | - | 35 |
| Net interest expense | **37** | **4** | **41** | 47 | - | 47 |

| | Nine Months Ended September 30, 2007 | | | Nine Months Ended September 30, 2006 | | |
|---|---|---|---|---|---|---|
| *(millions of dollars)* | As Stated | Impact of Rate Regulated Accounting | Financial Statements without Rate Regulated Accounting | As Stated | Impact of Rate Regulated Accounting | Financial Statements without Rate Regulated Accounting |
| Revenue | **4,318** | **22** | **4,340** | 4,288 | 25 | 4,313 |
| Fuel expense | **962** | **(4)** | **958** | 831 | - | 831 |
| Operations, maintenance, and administration | **2,159** | **20** | **2,179** | 1,946 | 13 | 1,959 |
| Depreciation and amortization | **519** | **(36)** | **483** | 525 | (21) | 504 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **381** | **56** | **437** | 375 | - | 375 |
| Property and capital taxes | **66** | **3** | **69** | 82 | - | 82 |
| Net interest expense | **102** | **29** | **131** | 145 | - | 145 |

*Accounting for Certain Leases*

OPG accounts for certain lease revenues relating to the regulated business using the cash basis of accounting. Under the cash basis of accounting, OPG recognizes lease income as stipulated in the lease agreement to the extent that the lease payments are expected to be included in future regulated prices charged to customers. If OPG did not apply the cash basis of accounting for certain lease revenues related to the regulated business, revenue for the three and nine months ended September 30, 2007 would have increased by $5 million and $15 million, respectively (three and nine months ended September 30, 2006 – $5 million and $15 million, respectively).

## 7. SHORT-TERM CREDIT FACILITIES

OPG's $1 billion revolving committed bank credit facility is divided into two tranches – a $500 million 364-day term tranche maturing May 21, 2008, and a $500 million five-year term tranche maturing May 22, 2012. The longer term tranche was extended from a three-year term to a five-year term, upon renewal of the bank credit facility in May 2007. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. As at September 30, 2007, there was no commercial paper outstanding (December 31, 2006 – $15 million). OPG had no other outstanding borrowing under its bank credit facility as at September 30, 2007.

OPG also maintains $25 million (December 31, 2006 – $26 million) in short-term uncommitted overdraft facilities as well as $238 million (December 31, 2006 – $240 million) of short-term uncommitted credit facilities, which support the issuance of Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans, and for other purposes including the requirement to post Letters of Credit as collateral with Local Distribution Companies ("LDCs") as prescribed by the OEB's Retail Settlement Code. At September 30, 2007, there was a total of $201 million (December 31, 2006 – $185 million) of Letters of Credit issued, which included $175 million (December 31, 2006 – $159 million) relating to the supplementary pension plans and $16 million (December 31, 2006 – $16 million) relating to the construction of the Portlands Energy Centre.

## 8. LONG-TERM DEBT

Long-term debt consists of the following:

| *(millions of dollars)* | **September 30 2007** | **December 31 2006** |
|---|---|---|
| Notes payable to the Ontario Electricity Financial Corporation | **3,215** | 3,165 |
| Share of non-recourse limited partnership debt | **189** | 194 |
| | **3,404** | 3,359 |
| Less: due within one year | | |
| Notes payable to the Ontario Electricity Financial Corporation | **400** | 400 |
| Share of limited partnership debt | **6** | 6 |
| | **406** | 406 |
| Long-term debt | **2,998** | 2,953 |

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 September 30, 2007 was $90 million (three months ended September 30, 2006 – $109 million), of which $86 million relates to interest paid on long-term debt (three months ended September 30, 2006 – $106 million). Interest paid during the nine months ended

September 30, 2007 was $200 million (nine months ended September 30, 2006 – $234 million), of which $187 million relates to interest paid on long-term debt (nine months ended September 30, 2006 – $223 million). Interest on the notes payable to the OEFC is paid semi-annually.

Debt financing for the Niagara Tunnel, the Portlands Energy Centre and the Lac Seul hydroelectric generating station projects are provided by the OEFC. As at September 30, 2007, OPG had issued under the credit facilities, $240 million for the Niagara Tunnel, $160 million for Portlands Energy Centre and $20 million for the Lac Seul hydroelectric station. This included new borrowing of $40 million under the Portlands Energy Centre facility during the three months ended September 30, 2007. For the nine months ended September 30, 2007, OPG borrowed $80 million under the Niagara Tunnel facility, and $70 million under the Portlands Energy Centre facility. The interest rate of these debt financing amounts ranges from 4.9 per cent to 5.4 per cent.

During the second quarter of 2007, OPG reached an agreement with the OEFC for a $500 million general corporate facility that is available for the period June 1, 2007 to March 31, 2008, and for a $950 million credit agreement to refinance senior notes as they mature over the period September 22, 2007 to September 22, 2009. In June 2007, OPG borrowed $100 million under its general corporate facility with the OEFC at 5.4 per cent. The note will mature in 2017. In September 2007, OPG met its debt retirement obligation of $200 million of maturing notes held by the OEFC by issuing new notes of $200 million under the $950 million refinancing credit facility at a rate of 5.5 per cent.

## 9. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT

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

| *(millions of dollars)* | **September 30 2007** | **December 31 2006** |
|---|---|---|
| Liability for nuclear used fuel management | **5,870** | 5,669 |
| Liability for nuclear decommissioning and low and intermediate level waste management | **4,792** | 4,659 |
| Liability for non-nuclear fixed asset removal | **195** | 192 |
| Fixed asset removal and nuclear waste management liability | **10,857** | 10,520 |

The change in the fixed asset removal and nuclear waste management liability for the nine months ended September 30, 2007 and the year ended December 31, 2006 are as follows:

| *(millions of dollars)* | **September 30 2007** | **December 31 2006** |
|---|---|---|
| Liability, beginning of period | **10,520** | 8,759 |
| Increase in liability due to accretion | **437** | 499 |
| Increase in liability due to nuclear used fuel and nuclear waste management variable expenses | **50** | 38 |
| Liabilities settled by expenditures on waste management | **(148)** | (164) |
| (Decrease) increase in the liability for non-nuclear fixed asset removal | **(2)** | 2 |
| Increase in the liability for nuclear used fuel management and the liability for nuclear decommissioning and low and intermediate level waste management to reflect the change in cost estimates | **-** | 1,386 |
| Liability, end of period | **10,857** | 10,520 |

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. Net changes resulting from revisions to the timing or the amount of the initial estimate are recognized as a change in the carrying amount of the liabilities, and a corresponding adjustment is made to the carrying value of the related fixed assets.

**Ontario Nuclear Funds Agreement**

OPG sets aside and invests funds in segregated custodian and trustee 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 September 30, 2007 and December 31, 2006 consist of the following:

| | **Fair Value** | | **Cost** |
|---|---|---|---|
| *(millions of dollars)* | **September 30 2007** | **December 31 2006** | **December 31 2006** |
| Decommissioning Fund | **5,157** | 5,169 | 4,356 |
| Due to Province – Decommissioning Fund | **(136)** | (294) | - |
| | **5,021** | 4,875 | 4,356 |
| Used Fuel Fund[1] | **4,286** | 3,879 | 3,338 |
| Due to Province – Used Fuel Fund | **(564)** | (641) | (100) |
| | **3,722** | 3,238 | 3,238 |
| | **8,743** | 8,113 | 7,594 |

[1] The Ontario NFWA Trust represented $1,218 million as at September 30, 2007 of the Used Fuel Fund on a fair value basis. The Ontario NFWA Trust represented $1,102 million as at December 31, 2006 of the Used Fuel Fund on an amortized cost and fair value basis.

As a result of the adoption of the new financial instrument accounting standards, assets in the Nuclear Funds are classified as held-for-trading, and therefore measured at fair value. At December 31, 2006, these assets were carried and reported at amortized cost.

As a result of adoption of the new financial instrument accounting standards, the Due to Province payable within each of the Nuclear Funds is measured at fair value with changes in fair value reported in net income.

## 10. INCOME TAXES

The following table summarizes the difference in the income statement amounts under the taxes payable method used by the Company to account for income taxes for the regulated business compared to what would have been reported had OPG applied the liability method for the regulated business for the three and nine months ended September 30, 2007 and 2006:

| *(millions of dollars)* | **Three Months Ended September 30 2007** | **Three Months Ended September 30 2006** | **Nine Months Ended September 30 2007** | **Nine Months Ended September 30 2006** |
|---|---|---|---|---|
| As Stated: | | | | |
| Future income tax expense | **5** | 4 | **14** | 56 |
| Future income tax: Other comprehensive income – Upon transition | **-** | - | **16** | - |
| Future income tax: Other comprehensive income – for the period | **(2)** | - | **(3)** | - |
| Liability method[1]: | | | | |
| Future income tax expense | **24** | 28 | **75** | 98 |
| Future income tax: Other comprehensive income – Upon transition | **-** | - | **12** | - |
| Future income tax: Other comprehensive income – for the period | **(7)** | - | **1** | - |

[1] As disclosed in Note 6, OPG accounts for certain lease revenues relating to the regulated business using the cash basis of accounting. The related future income tax impact is excluded from the above.

The following table summarizes the difference in the interim consolidated balance sheet amounts under the taxes payable method used by the Company to account for income taxes compared to what would have been reported had OPG applied the liability method for the regulated business as at September 30, 2007 and December 31, 2006:

| *(millions of dollars)* | **September 30, 2007 As Stated** | **September 30, 2007 Liability Method[1]** | **December 31, 2006 As Stated** | **December 31, 2006 Liability Method[1]** |
|---|---|---|---|---|
| Current future income tax liabilities | **(5)** | **(5)** | (3) | (4) |
| Long-term future income tax liabilities | **(272)** | **(505)** | (246) | (417) |

[1] As disclosed in Note 6, OPG accounts for certain lease revenues relating to the regulated business using the cash basis of accounting. The related future income tax impact is excluded from the above.

The amount of cash income taxes paid during the three months ended September 30, 2007 was nil (three months ended September 30, 2006 – $4 million). For the nine months ended September 30, 2007, cash income taxes paid were $52 million (nine months ended September 30, 2006 – $18 million).

## 11. 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 2007 costs are based on a measurement of the pension and OPEB obligations and the pension fund assets as at December 31, 2006.

Total benefit costs for the three and nine months ended September 30, 2007 and 2006 are as follows:

| | **Three Months Ended September 30** | | **Nine Months Ended September 30** | |
|---|---|---|---|---|
| *(millions of dollars)* | **2007** | **2006** | **2007** | **2006** |
| Registered pension plan | **61** | 54 | **182** | 163 |
| Supplementary pension plans | **4** | 4 | **11** | 11 |
| OPEB | **60** | 63 | **175** | 183 |

## 12. FINANCIAL INSTRUMENTS

*Risk Management and Hedging Activities*

OPG is exposed to changes in electricity prices associated with a wholesale spot market for electricity in Ontario. To hedge the commodity price risk exposure associated with changes in the wholesale price of electricity, OPG enters into various energy and related sales contracts. These contracts are expected to be effective as hedges of the commodity price exposure on OPG's generation portfolio. Gains or losses on hedging instruments are recognized in income when the underlying hedged transactions occur. These gains or losses are included in unregulated revenue and are recorded on the consolidated balance sheets. All contracts not designated as hedges are recorded as assets or liabilities at fair value with changes in fair value recorded in other revenue.

OPG also enters into derivative contracts with major financial institutions to manage the Company's exposure to foreign currency movements. Foreign exchange translation gains and losses on these foreign currency denominated derivative contracts are recognized as an adjustment to the purchase price of the commodity or goods received.

OPG is exposed to changes in market interest rates on debt expected to be issued in the future. OPG uses interest rate derivative contracts to hedge this exposure. Gains and losses on interest rate hedges are recorded as an adjustment to interest expense for the debt being hedged. Gains and losses that do not meet the effectiveness criteria are recorded through net income in the period incurred.

OPG utilizes emission reduction credits ("ERCs") and allowances to manage emissions within the prescribed regulatory limits. ERCs are purchased from trading partners in Canada and the United States. Emission allowances are obtained from the Province and purchased from trading partners in Ontario. The cost of ERCs and allowances are held in inventory and charged to OPG's operations at average cost as part of fuel expense as required. Options to purchase ERCs are accounted for as derivatives and are recorded at estimated market value.

*Hedge Accounting*

At the inception of a hedging relationship, OPG documents the relationship between the hedging instrument and the hedged item, its risk management objective and its strategy for undertaking the hedge. OPG also requires a documented assessment, both at hedge inception and on an ongoing basis, of whether or not the derivatives that are used in hedging transactions are highly effective in offsetting the changes attributable to the hedged risks in the fair values or cash flows of the hedged items.

Hedge accounting is applied when the derivative instrument is designated as a hedge and is expected to be effective throughout the life of the hedged item. When such derivative instrument ceases to exist or be effective as a hedge, 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.

*Determination of Fair Value*

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

Forward pricing information is inherently uncertain so that fair values of derivative instruments may not accurately represent the cost to enter into these positions. To address the impact of some of this uncertainty on trading positions, OPG established liquidity reserves against the mark-to-market gains or losses of these positions. These reserves decreased trading revenue by $1 million during the three months ended September 30, 2007 (three months ended September 30, 2006 – increased by $3 million). During the nine months ended September 30, 2007, the reserves decreased trading revenue by $1 million (nine months ended September 30, 2006 – decreased trading revenue by $2 million).

*Derivative Instruments Qualifying for Hedge Accounting*

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 in net income upon settlement when the underlying transactions occur. OPG holds financial commodity derivatives primarily to hedge the commodity price exposure associated with changes in the price of electricity.

| *(millions of dollars except where noted)* | **Notional Quantity** | **Terms** | **Fair Value** | **Notional Quantity** | **Terms** | **Fair Value** |
|---|---|---|---|---|---|---|
| | **September 30, 2007** | | | **December 31, 2006** | | |
| Gain (loss) | | | | | | |
| Electricity derivative instruments | **2.3 TWh** | **1-4 yrs** | **49** | 4.3 TWh | 1-4 yrs | 51 |
| Foreign exchange derivative instruments | **U.S. $70** | **July/08** | **(4)** | U.S. $2 | Jan./07 | - |
| Floating to fixed interest rate hedges | **43** | **1-12 yrs** | **1** | 45 | 1-12 yrs | (3) |
| Forward start interest rate hedges | **767** | **1-13 yrs** | **4** | 622 | 1-14 yrs | (9) |

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 September 30, 2007 was U.S. $0.95 (December 31, 2006 – U.S. $0.87) for every Canadian dollar.

One of the Company's joint ventures is exposed to changes in interest rates. The joint venture entered into an interest rate swap to manage the risk arising from fluctuations in interest rates by swapping the short-term floating interest rate with a fixed rate of 5.33 per cent. OPG's proportionate interest in the swap is 50 per cent and is accounted for as a hedge.

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 and the Portlands Energy Centre projects, and OPG's general corporate facility. Although these transactions are ordinarily accounted for as hedges, a gain of approximately $3 million was recorded to account for ineffectiveness in the hedges for the nine months ended September 30, 2006.

For the three and nine month periods ended September 30, 2007, OPG has de-designated a number of forward start interest rate hedges as the previously anticipated future borrowings associated with these instruments no longer being expected to occur. As a result of the de-designation, a gain of $1 million was reclassified to net income for the nine month period ended September 30, 2007.

Net gains of $10 million and $27 million related to electricity derivative instruments qualifying for hedge accounting were recognized in net income during the three and nine months ended September 30, 2007, respectively. These amounts were previously recorded in other comprehensive income.

Existing net gains of $27 million deferred in accumulated other comprehensive income at September 30, 2007 are expected to be reclassified to net income within the next 12 months.

*Derivative Instruments Not Qualifying for Hedge Accounting*

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

| *(millions of dollars except where noted)* | **Notional Quantity** | **Fair Value** | **Notional Quantity** | **Fair Value** |
|---|---|---|---|---|
| | **September 30, 2007** | | **December 31, 2006** | |
| Foreign exchange derivative instruments | **U.S. $14** | **(2)** | - | - |
| Commodity derivative instruments | | | | |
| Assets | **7.7 TWh** | **14** | 3.9 TWh | 25 |
| Liabilities | **1.4 TWh** | **(11)** | 2.6 TWh | (25) |
| | | **3** | | - |
| Market liquidity reserve | | **(3)** | | (2) |
| Total | | **-** | | (2) |

Foreign exchange derivative instruments that are not designated as hedges have a weighted average exchange rate of U.S. $0.86 at September 30, 2007.

**Fair Value of Other Financial Instruments**

The carrying values of cash and cash equivalents, accounts receivable, accounts payable and accrued charges, and short-term notes payable approximate their fair values due to the immediate or short-term maturity of these financial instruments. Fair values for other financial instruments have been estimated by reference to quoted market prices for actual or similar instruments where available.

The carrying values and fair values of these other financial instruments as at September 30, 2007 and December 31, 2006 are as follows:

| *(millions of dollars)* | **Carrying Value** | **Fair Value** | **Carrying Value** | **Fair Value** |
|---|---|---|---|---|
| | **September 30, 2007** | | **December 31, 2006** | |
| Financial Assets | | | | |
| Nuclear fixed asset removal and nuclear waste management funds | **8,743** | **8,743** | 7,594 | 8,113 |
| Long-term accounts receivable and other assets | **124** | **124** | 69 | 69 |
| Financial Liabilities | | | | |
| Long-term debt due within one year | **406** | **416** | 406 | 409 |
| Long-term debt | **2,998** | **3,232** | 2,953 | 3,082 |
| Long-term accounts payable and accrued charges | **184** | **184** | 150 | 150 |

### 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. The majority of OPG revenues are derived from sales through the Independent Electricity System Operator ("IESO") administered spot market. However, OPG also derives revenue from several other sources including the sale of energy products and financial risk management products to third parties.

Credit exposure to the IESO fluctuates based on spot prices and the volume of rate regulated and unregulated generation, and is reduced each month upon settlement of the accounts. Credit exposure to the IESO peaked at $883 million during the nine months ended September 30, 2007 ($1,029 million during the year ended December 31, 2006).

## 13. COMMITMENTS AND CONTINGENCIES

### Litigation

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

On August 9, 2006, a Notice of Action and Statement of Claim in the amount of $500 million (the "Claim") was served on OPG and Bruce Power L.P. by British Energy Limited and British Energy International Holdings Limited ("British Energy"), claiming that OPG is liable to them for breach of contract and negligence. OPG leased the Bruce nuclear generating stations to Bruce Power L.P. in 2001. British Energy was an investor in Bruce Power L.P. In 2003, British Energy sold its interest in Bruce Power L.P. to a group of investors (the "Purchasers"). The Purchasers are claiming that British Energy is liable to them with respect to this purchase transaction. Their claim is currently the subject of an arbitration proceeding (the "Arbitration"). British Energy is therefore suing OPG in order to preserve any similar claim it may have against OPG pursuant to the 2001 lease transaction. British Energy has indicated that it does not require OPG to actively defend the Claim at this point in time as British Energy is defending the Arbitration commenced by the Purchasers. The Arbitration may narrow or eliminate the claims or damages British Energy has, so as to narrow or eliminate the need to continue the Claim against OPG. British Energy has reserved the right to require OPG to defend the Claim prior to the conclusion of the Arbitration should British Energy at some point believe there is some advantage in doing so.

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. For the nine months ended September 30, 2007, OPG recorded additional expenses associated with past grievances by First Nations.

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 September 30, 2007, expenditures of nil (three months ended September 30, 2006 – $1 million) were recorded against the provision. During the nine months ended September 30, 2007, OPG recorded expenditures of $2 million (nine months ended September 30, 2006 – $3 million). As at September 30, 2007, the remaining provision was $50 million (December 31, 2006 – $52 million).

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

**Guarantees**

As part of normal business, OPG and certain of its subsidiaries and joint ventures 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.

## 14. REVENUE LIMIT REBATE

Eighty-five per cent of the generation output from OPG's unregulated generation assets, excluding the Lennox generating station and forward sales as of January 1, 2005, is subject to a revenue limit. The output from a generating unit where there has been a fuel conversion and the incremental output from a generating station where there has been a refurbishment or expansion of these assets is also excluded from the output covered by the revenue limit. In addition, until the Transition – Generation Corporation Designated Rate Options ("TRO") expired on April 30, 2006, volumes sold under such options were also excluded from the revenue limit rebate.

The revenue limit, which was originally established for a period of 13 months ending April 30, 2006, was subsequently extended for an additional three years. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh. On May 1, 2007, the revenue limit returned to 4.7¢/kWh and it will increase to 4.8¢/kWh effective May 1, 2008. In addition, beginning April 1, 2006, volumes sold under a Pilot Auction administered by the Ontario Power Authority ("OPA") are subject to a revenue limit that is 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Revenues above these limits are returned to the IESO for the benefit of consumers.

The change in the revenue limit rebate liability for the nine months ended September 30, 2007 and the year ended December 31, 2006 are as follows:

| *(millions of dollars)* | **September 30 2007** | **December 31 2006** |
|---|---|---|
| Liability, beginning of the period | **40** | 739 |
| Increase to provision during the period | **176** | 161 |
| Payments made during the period | **(149)** | (860) |
| Liability, end of period | **67** | 40 |

## 15. BUSINESS SEGMENTS

Effective April 1, 2005, the output from most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that it operates 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 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.

OM&A expenses of the generation business segments include an inter-segment service fee for the use of certain property, plant and equipment of the Other category. The total service fee is recorded as a reduction to the Other category's OM&A expenses. For the three months ended September 30, 2007, the service fee was $11 million for Regulated – Nuclear, $1 million for Regulated – Hydroelectric, $1 million for Unregulated – Hydroelectric and $4 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $17 million for the Other category. For the three months ended September 30, 2006, the service fee was $9 million for Regulated – Nuclear, $1 million for Regulated – Hydroelectric, $1 million for Unregulated – Hydroelectric and $2 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $13 million for the Other category.

For the nine months ended September 30, 2007, the service fee was $25 million for Regulated – Nuclear, $2 million for Regulated – Hydroelectric, $3 million for Unregulated – Hydroelectric and $8 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $38 million for the Other category. For the nine months ended September 30, 2006, the service fee was $23 million for Regulated – Nuclear, $2 million for Regulated – Hydroelectric, $3 million for Unregulated – Hydroelectric and $7 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $35 million for the Other category. Results for the three months ended March 31, 2006 have been reclassified to reflect the service fee.

| **Segment (Loss) Income for Three Months Ended September 30, 2007** | **Regulated** | | **Unregulated** | | | |
|---|---|---|---|---|---|---|
| | **Nuclear** | **Hydro-electric** | **Hydro-electric** | **Fossil-Fuelled** | **Other** | **Total** |
| *(millions of dollars)* | | | | | | |
| Revenue | **629** | **171** | **162** | **483** | **36** | **1,481** |
| Revenue limit rebate | **-** | **-** | **(16)** | **(44)** | **-** | **(60)** |
| | **629** | **171** | **146** | **439** | **36** | **1,421** |
| Fuel expense | **33** | **60** | **19** | **224** | **-** | **336** |
| Gross margin | **596** | **111** | **127** | **215** | **36** | **1,085** |
| Operations, maintenance and administration | **487** | **23** | **44** | **130** | **5** | **689** |
| Depreciation and amortization | **104** | **16** | **15** | **20** | **13** | **168** |
| Accretion on fixed asset removal and nuclear waste management liabilities | **124** | **-** | **-** | **3** | **-** | **127** |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(92)** | **-** | **-** | **-** | **-** | **(92)** |
| Property and capital taxes | **3** | **3** | **3** | **5** | **3** | **17** |
| (Loss) income before interest and income taxes | **(30)** | **69** | **65** | **57** | **15** | **176** |

| **Segment Income for Three Months Ended September 30, 2006** | **Regulated** | | **Unregulated** | | | |
|---|---|---|---|---|---|---|
| | **Nuclear** | **Hydro-electric** | **Hydro-electric** | **Fossil-Fuelled** | **Other** | **Total** |
| *(millions of dollars)* | | | | | | |
| Revenue | 722 | 175 | 133 | 422 | 42 | 1,494 |
| Revenue limit rebate | - | - | (16) | (43) | - | (59) |
| | 722 | 175 | 117 | 379 | 42 | 1,435 |
| Fuel expense | 34 | 62 | 15 | 199 | - | 310 |
| Gross margin | 688 | 113 | 102 | 180 | 42 | 1,125 |
| Operations, maintenance and administration | 440 | 26 | 47 | 115 | - | 628 |
| Depreciation and amortization | 91 | 16 | 17 | 17 | 13 | 154 |
| Accretion on fixed asset removal and nuclear waste management liabilities | 123 | - | - | 2 | - | 125 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | (82) | - | - | - | - | (82) |
| Property and capital taxes | 15 | 6 | 4 | 7 | 3 | 35 |
| Income before interest and income taxes | 101 | 65 | 34 | 39 | 26 | 265 |

| Segment Income for Nine Months Ended September 30, 2007 | Regulated<br>Nuclear | Regulated<br>Hydro-electric | Unregulated<br>Hydro-electric | Unregulated<br>Fossil-Fuelled | Other | Total |
|---|---|---|---|---|---|---|
| *(millions of dollars)* | | | | | | |
| Revenue | **1,943** | **526** | **581** | **1,341** | **103** | **4,494** |
| Revenue limit rebate | **-** | **-** | **(48)** | **(128)** | **-** | **(176)** |
| | **1,943** | **526** | **533** | **1,213** | **103** | **4,318** |
| Fuel expense | **98** | **179** | **58** | **627** | **-** | **962** |
| Gross margin | **1,845** | **347** | **475** | **586** | **103** | **3,356** |
| Operations, maintenance and administration | **1,496** | **97** | **146** | **414** | **6** | **2,159** |
| Depreciation and amortization | **320** | **50** | **50** | **59** | **40** | **519** |
| Accretion on fixed asset removal and nuclear waste management liabilities | **374** | **-** | **-** | **7** | **-** | **381** |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(392)** | **-** | **-** | **-** | **-** | **(392)** |
| Property and capital taxes | **23** | **10** | **8** | **16** | **9** | **66** |
| Income before interest and income taxes | **24** | **190** | **271** | **90** | **48** | **623** |

| Segment Income for Nine Months Ended September 30, 2006 | Regulated<br>Nuclear | Regulated<br>Hydro-electric | Unregulated<br>Hydro-electric | Unregulated<br>Fossil-Fuelled | Other | Total |
|---|---|---|---|---|---|---|
| *(millions of dollars)* | | | | | | |
| Revenue | 2,067 | 514 | 587 | 1,150 | 118 | 4,436 |
| Revenue limit rebate | - | - | (42) | (106) | - | (148) |
| | 2,067 | 514 | 545 | 1,044 | 118 | 4,288 |
| Fuel expense | 93 | 174 | 60 | 504 | - | 831 |
| Gross margin | 1,974 | 340 | 485 | 540 | 118 | 3,457 |
| Operations, maintenance and administration | 1,378 | 70 | 128 | 375 | (5) | 1,946 |
| Depreciation and amortization | 275 | 49 | 49 | 113 | 39 | 525 |
| Accretion on fixed asset removal and nuclear waste management liabilities | 368 | - | - | 7 | - | 375 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | (274) | - | - | - | - | (274) |
| Property and capital taxes | 34 | 14 | 11 | 15 | 8 | 82 |
| Income before interest and income taxes | 193 | 207 | 297 | 30 | 76 | 803 |

| (millions of dollars) | Regulated Nuclear | Regulated Hydro-electric | Unregulated Hydro-electric | Unregulated Fossil-Fuelled | Other | Total |
|---|---|---|---|---|---|---|
| **Selected Balance Sheet Information** | | | | | | |
| As at September 30, 2007 | | | | | | |
| Segment fixed assets in service, net | **4,009** | **3,887** | **3,004** | **401** | **516** | **11,817** |
| Segment construction work in progress | **255** | **274** | **82** | **57** | **276** | **944** |
| Segment property, plant and equipment, net | **4,264** | **4,161** | **3,086** | **458** | **792** | **12,761** |
| Segment materials and supplies inventory, net: | | | | | | |
| Short-term | **67** | **1** | **-** | **51** | **-** | **119** |
| Long-term | **336** | **-** | **3** | **4** | **-** | **343** |
| Segment fuel inventory | **153** | **-** | **-** | **355** | **-** | **508** |
| As at December 31, 2006 | | | | | | |
| Segment fixed assets in service, net | 4,213 | 3,907 | 3,012 | 408 | 544 | 12,084 |
| Segment construction work in progress | 165 | 252 | 78 | 49 | 133 | 677 |
| Segment property, plant and equipment, net | 4,378 | 4,159 | 3,090 | 457 | 677 | 12,761 |
| Segment materials and supplies inventory, net: | | | | | | |
| Short-term | 63 | 1 | - | 48 | - | 112 |
| Long-term | 320 | - | 3 | 3 | - | 326 |
| Segment fuel inventory | 183 | - | - | 486 | - | 669 |
| **Selected Cash Flow Information** | | | | | | |
| Three months ended September 30, 2007 | | | | | | |
| Investment in fixed assets | **51** | **16** | **21** | **31** | **60** | **179** |
| Three months ended September 30, 2006 | | | | | | |
| Investment in fixed assets | 40 | 51 | 24 | 19 | 54 | 188 |
| Nine months ended September 30, 2007 | | | | | | |
| Investment in fixed assets | **142** | **53** | **46** | **59** | **176** | **476** |
| Nine months ended September 30, 2006 | | | | | | |
| Investment in fixed assets | 118 | 121 | 50 | 47 | 86 | 422 |

### 16. CHANGES IN NON-CASH WORKING CAPITAL BALANCES

| *(millions of dollars)* | **Three Months Ended September 30** **2007** | **2006** | **Nine Months Ended September 30** **2007** | **2006** |
|---|---|---|---|---|
| Accounts receivable | **66** | 45 | **(4)** | 331 |
| Prepaid expenses | **(33)** | (8) | **(33)** | (23) |
| Fuel inventory | **50** | 12 | **161** | (36) |
| Materials and supplies | **(3)** | (4) | **(7)** | 1 |
| Revenue limit rebate | **60** | 59 | **176** | 148 |
| Accounts payable and accrued charges | **(35)** | (11) | **(173)** | (167) |
| Income and capital taxes payable | **31** | 50 | **50** | 86 |
| | **136** | 143 | **170** | 340 |

### 17. SEASONAL OPERATIONS

OPG's quarterly results are impacted by changes in demand resulting from variations in seasonal weather conditions. Historically, OPG's revenues are higher in the first and third quarters of a fiscal year as a result of winter heating demands in the first quarter and air conditioning/cooling demands in the third quarter. Regulated prices for most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that OPG operates, 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.