ONTARIO POWER GENERATION

News
from Ontario Power Generation

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ONTARIO POWER GENERATION REPORTS 2003 THIRD QUARTER EARNINGS

[Toronto]: Ontario Power Generation Inc. ("OPG") today reported its financial and operating results for the third quarter and nine months ended September 30, 2003. Net income for the three months ended September 30, 2003 was $37 million or $0.14 per share, compared with $215 million or $0.84 per share for the three months ended September 30, 2002. For the nine months ended September 30, 2003, net income was $125 million or $0.49 per share compared to $61 million or $0.24 per share for the same period last year.

OPG's third quarter earnings reflect lower energy prices and reduced electricity production. Ontario energy prices were lower due to more moderate summer temperatures and lower electricity demand during the third quarter of 2003 than the same period last year. Electricity produced was lower during the quarter reflecting reduced fossil production in response to lower demand and lower nuclear output due to higher planned and forced outages at the Pickering B nuclear station. OPG's Darlington nuclear generating station continued to perform well, with a net capacity factor of 92 per cent during the third quarter.

OPG's net income for the nine months ended September 30, 2003 was above that of the same period last year. The impact of higher energy prices during the first nine months of 2003 compared to the same period last year as well as lower Pickering A return to service expenditures was more than offset by lower electricity production and higher fossil fuel costs. However, in the first quarter of 2002, OPG recorded provisions for transitional price relief to certain power customers upon market opening and restructuring charges, which significantly reduced earnings last year.

On Thursday August 14, 2003, a power blackout affected Ontario and the northeastern United States. OPG took immediate action to return our 22,200 megawatts of capacity to service. Our Hydroelectric stations were reconnected to the transmission system within hours of the blackout. By Friday August 15, 2003, about 60 per cent of our generating capacity, including our hydroelectric stations, a significant portion of fossil capacity and some nuclear capacity, had returned to service. By Monday August 18, 2003, about 85 per cent of available capacity was reconnected to the transmission system, including all four units at OPG's Darlington nuclear generating station. By August 25, 2003, about 95 per cent of available capacity was reconnected to the transmission system, including significant Pickering nuclear generating capacity. Generating capacity was fully restored by August 29, 2003. OPG has estimated that the blackout resulted in a reduction in net income of approximately $40 to $50 million, including the impact of lost revenue and higher operating costs to restore generating capacity.

In August, Unit 4 of the Pickering A nuclear generating station was reconnected to the Ontario transmission system. Following a series of successful tests, on September 25, 2003, OPG declared Unit 4 to be commercially available and informed the Independent Electricity Market Operator that the unit was available for dispatch into the Ontario market.

Ontario Power Generation Inc. is an Ontario-based company, whose principal business is the generation and sale of electricity in Ontario and to interconnected markets. Our focus is on the risk-managed production and sale of reliable electricity from our competitive generation assets. OPG's goal is to be a premier North American energy company, while operating in a safe, open and environmentally responsible manner.

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MANAGEMENT'S DISCUSSION AND ANALYSIS

This discussion and analysis should be read in conjunction with the unaudited 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, 2003. It should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, Management's Discussion and Analysis, and the Annual Information Form for the year ended December 31, 2002. OPG's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles and are presented in Canadian dollars. Certain 2002 comparative amounts have been reclassified to conform with the 2003 financial statement presentation.

THE COMPANY

OPG is an Ontario-based electricity generation company focused on the cost effective, safe and environmentally responsible production, sale and purchase of electricity and energy-related risk management products and related services in Ontario and the interconnected markets of Quebec, Manitoba and the northeast and midwest regions of the United States. OPG was incorporated under the *Business Corporations Act* (Ontario) and is wholly-owned by the Province of Ontario.

As at September 30, 2003, OPG's electricity generating portfolio consisted of three nuclear stations, six fossil-fueled generating stations, 36 hydroelectric generating stations and an EcoLogo™ - certified green power portfolio including 29 small hydro and three wind generating stations. OPG's Pickering A nuclear generating station has been laid up since 1997. OPG recently completed the return to service of the first unit of this four-unit station. In addition, there are two other nuclear generating stations that are leased on a long-term basis to Bruce Power L.P. ("Bruce Power").

HIGHLIGHTS

	Three Months Ended September 30		Nine Months Ended September 30	
	2003	**2002**	**2003**	**2002**
(millions of dollars)				
Revenues	**1,224**	1,612	**3,950**	4,432
Net income	**37**	215	**125**	61
Cash flow provided by (used in) operating activities	**(642)**	446	**(74)**	534
Physical Electricity Sales Volume (TWh)				
Total production	**27.0**	28.9	**82.1**	87.7
Purchased power – Generation segment [1]	**-**	-	**-**	7.4
– Energy Marketing segment	**1.2**	0.6	**3.3**	1.0
Other	**-**	-	**-**	0.1
Total	**28.2**	29.5	**85.4**	96.2

[1] Purchased power in 2002 was primarily from Bruce Power L.P. Under an operating lease agreement, until market opening on May 1, 2002, OPG was obligated to purchase and resell all of Bruce Power's electricity generation.

Net income for the third quarter ended September 30, 2003 was $37 million compared to net income of $215 million for the same period in 2002, a decrease of $178 million. For the nine months ended September 30, 2003, net income was $125 million compared with $61 million last year, an increase of $64 million. Significant factors impacting earnings in 2003 compared to 2002, on an after-tax basis, included the following:

(millions of dollars – after tax)	**Three Months**	**Nine Months**
Net income for the three and nine month periods ended September 30, 2002	215	61
Change in energy prices	(116)	87
Higher prices for fossil fuel and change in generation mix [1]	18	(75)
Lower volume and other changes in gross margin [1]	(128)	(209)
Lower Pickering A return to service expenses	40	55
Increased OM&A expenses due to higher nuclear outage and project costs	(22)	(59)
Loss on Transition Rate Option contracts for industrial customers recorded in 2002	-	140
Restructuring charges recorded in 2002	7	141
Increase (decrease) in other income	5	(51)
Other net changes	18	35
Net income for the three and nine month periods ended September 30, 2003	37	125

[1] The impact of the August 14, 2003 blackout resulted in a reduction in net income of $40 to $50 million for the three and nine month periods ended September 30, 2003.

On Thursday August 14, 2003, a power blackout affected Ontario and the northeastern United States. Following the blackout, OPG took immediate action to return its generating stations to service. Hydroelectric stations were reconnected to the transmission system within hours of the blackout. By Friday August 15, 2003, about 60 per cent of OPG's generating capacity, including OPG's hydroelectric stations and a significant portion of fossil station capacity and some nuclear capacity, was reconnected to the transmission system. By Monday August 18, 2003, about 85 per cent of OPG's available capacity was reconnected to the transmission system, including all four units at OPG's Darlington nuclear generating station. By August 25, 2003, about 95 per cent of available capacity was reconnected to the transmission system including significant Pickering nuclear generating capacity. Generating capacity was fully restored by August 29, 2003.

Subsequent to the blackout, the Provincial Government requested that industrial, commercial and residential customers reduce their consumption by 50 per cent during peak hours. Customer response to requests for curtailment and conservation, together with continued dispatch of emergency generators and emergency purchases from interconnected markets allowed a reliable supply to be maintained. OPG has estimated that the blackout resulted in a reduction in net income of approximately $40 million to $50 million, including the impact of lost revenue and higher operating costs to restore generating capacity.

On August 21, 2003, as part of the commissioning process, Unit 4 of the Pickering A nuclear generating station was successfully reconnected to the Ontario transmission system. During the following month, electricity continued to be generated from the unit. On September 25, 2003, OPG declared Unit 4 to be commercially available and informed the Independent Electricity Market Operator ("IMO") that the unit was available for dispatch into the Ontario market.

Cash flow used in operating activities in the third quarter of 2003 was $642 million compared to cash flow provided by operating activities of $446 million in the third quarter of 2002, a decrease of $1,088 million. The decrease in cash flow compared to last year was primarily due to payment of the Market Power Mitigation Agreement rebate of $806 million in August 2003, contributions to the pension fund, and other changes in working capital.

Cash flow used in operating activities for the nine month period ended September 30, 2003 was $74 million compared to cash flow provided by operating activities of $534 million for the nine month period ended September 30, 2002, a decrease of $608 million. The decrease in cash flow was mainly due to payments of the Market Power Mitigation Agreement rebate totalling $1,565 million, increased contributions to the nuclear fixed asset removal and nuclear waste management funds due to timing and contributions to the pension fund. The impact of these factors was partially offset by higher energy prices, proceeds from the payment of the $225 million receivable from Bruce Power and other changes in working capital.

ONTARIO ELECTRICITY MARKET

In December 2002, the Government of Ontario passed into law the *Electricity Pricing, Conservation and Supply Act, 2002*. Along with certain other changes, the new legislation and related regulations set electricity commodity prices at 4.3¢/kWh for low volume consumers (consumers using up to 150,000 kWh annually), those consumers who have a demand of 50 kW or less, and other designated consumers. The 4.3¢/kWh price was retroactive to May 1, 2002 and is fixed until April 30, 2006.

In March 2003, the Province announced a Business Protection Plan for large electricity consumers in Ontario. Under this plan, consumers using up to 250,000 kWh per year are included in the fixed price of 4.3¢/kWh retroactive to May 1, 2002. Except for certain designated customers, all consumers using above 250,000 kWh per year remain in the competitive markets and will receive rebates under the terms of the existing Market Power Mitigation Agreement for the 12 months ended April 30, 2003. Effective May 1, 2003, rebates to these customers are fixed at 50 per cent of the amount by which the average spot price in the market administered by the IMO exceeds 3.8¢/kWh, and will be paid quarterly by the IMO.

OPG continues to be responsible for a rebate commitment based on the existing Market Power Mitigation Agreement under which the level of payment is impacted by the degree of decontrol implemented by OPG. The Business Protection Plan is not expected to have a material impact on OPG's results from operations.

In April 2003, the Minister of Energy issued a Directive setting out the procedure for calculating, allocating and passing through the Market Power Mitigation Agreement rebate. Under the Directive, the first rebate payment was based on the nine-month period that commenced on market opening, May 1, 2002, and ended January 31, 2003, less OPG's interim payment to the IMO of $335 million. OPG paid a rebate of $759 million to the IMO in May, 2003. A second rebate payment of $806 million was remitted in August, 2003 for the three-month period ended April 30, 2003. For subsequent periods through April 30, 2006, OPG will make quarterly rebate payments to the IMO. The IMO will make payments to market participants in accordance with the terms of the Directive.

PROVINCIAL ELECTION

A provincial election was called on September 2, 2003. During the election campaign, statements and political platforms referenced OPG's operations and the Ontario electricity sector. Following the October 2, 2003 election, OPG will be discussing these matters with the new government and seeking direction of the shareholder in the near future.

BUSINESS SEGMENTS

With the opening of Ontario's electricity market to competition on May 1, 2002, OPG began operating two reportable business segments: Generation and Energy Marketing. A separate category, Non-Energy and Other, includes revenue and certain costs that are not allocated to the business segments.

Generation Segment

OPG's principal business segment operates in Ontario, generating and selling electricity. Commencing with the opening of the Ontario electricity market on May 1, 2002, all of OPG's electricity generation is sold into the IMO-administered real-time energy spot market. As such, the majority of OPG's revenue is derived from spot market sales. In addition to revenue earned from spot market sales, revenue is also earned through offering available 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. Prior to market opening, OPG sold electricity directly to wholesale electricity customers in Ontario and to interconnected markets in Quebec, Manitoba and the U.S. northeast and midwest.

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 a spot market for electricity in Ontario. Contracts that are designated as hedges of OPG's generation revenues are included in Generation segment activities. Gains or losses on these hedging instruments are recognized in revenue over the term of the contract when the underlying hedged transactions occur.

Energy Marketing Segment

The Energy Marketing segment derives revenue from various financial and physical energy market transactions with large volume end-use customers and intermediaries such as utilities, brokers, aggregators, traders and other power marketers and retailers. Energy marketing in deregulated markets includes trading, the sale of financial risk management products and sales of energy-related products and services to meet customers' needs for energy solutions. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in Energy Marketing revenue as gains or losses. OPG purchases and sells electricity through the IMO market and the interconnected markets of other provinces and the U.S. northeast and midwest.

Non-Energy and Other

OPG derives non-energy revenue under the terms of a lease arrangement with Bruce Power related to the Bruce nuclear generating stations. This includes lease revenue, interest income and revenue from engineering analysis and design, technical and other services. Non-energy revenue also includes isotope sales to the medical industry and real estate rentals.

DISCUSSION OF OPERATING RESULTS

Generation Segment

(millions of dollars)	Three Months Ended September 30 2003	Three Months Ended September 30 2002	Nine Months Ended September 30 2003	Nine Months Ended September 30 2002
Revenue	**1,143**	1,504	**3,669**	4,160
Fuel	**383**	412	**1,265**	1,147
Power purchased	**-**	-	**-**	290
Gross margin	**760**	1,092	**2,404**	2,723
Operations, maintenance and administration				
Expenses excluding Pickering A Return to Service	**484**	457	**1,535**	1,440
Pickering A Return to Service	**50**	112	**220**	307
Depreciation and amortization	**118**	118	**340**	343
Accretion on fixed asset removal and nuclear waste management liabilities	**107**	106	**318**	321
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(74)**	(60)	**(188)**	(178)
Property and capital taxes	**24**	26	**73**	79
Operating income	**51**	333	**106**	411

Gross Margin

Gross margin from electricity sales in the Generation segment was $760 million for the third quarter of 2003 compared to $1,092 million for the same period in 2002, a decrease of $332 million. The decrease in gross margin during the third quarter was mainly due to lower electricity prices and lower generation, including the impact of the August 14, 2003 blackout.

Gross margin from electricity sales in the Generation segment was $2,404 million for the nine months ended September 30, 2003 compared to $2,723 million for the same period last year , a decrease of $319 million. The decrease in gross margin was mainly due to lower electricity generation, including the impact of the blackout; a change in the generation mix related to higher production from fossil stations and lower production from nuclear and hydroelectric stations; and higher costs for coal, oil, and natural gas fuel for fossil stations. The impact of these factors on gross margin was partially offset by higher energy prices over the nine month period in 2003 compared to last year.

The reduction in gross margin resulting from the blackout is estimated to be approximately $60 million to $70 million for both the three and nine month periods ended September 30, 2003.

Upon closing the operating lease agreement for the Bruce nuclear generating stations with Bruce Power in May 2001, OPG was obligated to purchase and resell all of Bruce Power's electricity generation up to May 1, 2002, the date the Ontario electricity market opened. Upon market opening, Bruce Power began selling electricity directly into the IMO-administered real-time energy spot market, thereby lowering OPG's volume and revenue and eliminating the associated costs for power purchases from Bruce Power. The impact of the Bruce decontrol on gross margin in the nine month period ended September 30, 2003 compared to the same period in 2002 was not significant.

Revenue

(millions of dollars)	Three Months Ended September 30 2003	Three Months Ended September 30 2002	Nine Months Ended September 30 2003	Nine Months Ended September 30 2002
Spot market sales, net of market power mitigation agreement rebate and financial transactions	**1,126**	1,485	**3,610**	2,153
Electricity sales (prior to market opening)	**-**	-	**-**	1,939
Other	**17**	19	**59**	68
Total generation revenue	**1,143**	1,504	**3,669**	4,160

Generation revenue was $1,143 million for the three month period ended September 30, 2003 compared to $1,504 million for the same period last year, a decrease of $361 million. The decrease was primarily due to lower electricity prices, and to a lesser extent, a reduction in electricity sales volumes resulting from lower generation.

For the nine month period ended September 30, 2003, generation revenue was $3,669 million compared to $4,160 million for the same period in 2002, a decrease of $491 million. The decrease in generation revenue was due to lower electricity sales volumes resulting from the termination, upon market opening, of the agreement to purchase and resell all of Bruce Power's electricity generation, and lower production from OPG's generating stations. The impact of these reductions on revenue was partially offset by higher electricity prices.

Electricity Prices

Spot market prices in Ontario during the three months ended September 30, 2003 were impacted by more moderate summer temperatures and lower electricity demand in Ontario compared to the same period last year. Extended periods of unusually warm temperatures in Ontario in the summer of 2002 prompted high electricity demand, resulting in high spot market prices last year. There were 257 Cooling Degree Days[1] during the three months ended September 30, 2003 compared to 419 Cooling Degree Days for the same period in 2002. The ten-year weather normal average for the three month period is 254 Cooling Degree Days.

A significant portion of OPG's energy sales are subject to an average annual revenue cap of 3.8¢/kWh through the Market Power Mitigation Agreement rebate mechanism. OPG's average spot market sales price for the third quarter of 2003, after taking into account the Market Power Mitigation Agreement rebate, was 4.1¢/kWh compared to 5.2¢/kWh for the same period last year.

During the nine months ended September 30, 2003, spot market prices in Ontario were higher when compared to last year due primarily to prolonged cold winter temperatures and a cool spring, and higher natural gas prices. There were 2,743 Heating Degree Days[2] during the nine months ended September 30, 2003 compared to 2,275 Heating Degree Days for the same period in 2002. The ten-year weather normal average for the nine month period is 2,504 Heating Degree Days. OPG's average spot market sales price for the first nine months of 2003, after taking into account the Market Power Mitigation Agreement rebate, was 4.5¢/kWh compared to the fixed revenue rate of 4.0¢/kWh prior to market opening on May 1, 2002 and 4.5¢/kWh from May 1, 2002 to September 30, 2002.

[1] Cooling Degree Days represent the aggregate of the average daily temperatures above 18^{0}C, as measured at Pearson International Airport in Toronto.

[2] Heating Degree Days represent the aggregate of the average daily temperatures below 18^{0}C, as measured at Pearson International Airport in Toronto.

Market Power Mitigation Agreement Rebate

To address the potential for OPG to exercise market power in Ontario, OPG is directed under its generation licence to comply with prescribed market power mitigation measures, including a rebate mechanism. Under the rebate mechanism, for the first four years after market opening, a majority of OPG's expected energy sales in Ontario is subject to an average annual revenue cap of 3.8¢/kWh. OPG is required to pay a rebate to the IMO equal to the excess, if any, of the average hourly spot energy price over 3.8¢/kWh for the amount of energy sales subject to the rebate mechanism. At each balance sheet date, OPG computes the average spot energy price that prevailed since the beginning of the current settlement period and recognizes a liability if the average price exceeds 3.8¢/kWh, based on the amount of energy subject to the rebate mechanism.

Under OPG's generation licence, issued by the Ontario Energy Board ("OEB"), the Company has the ability to reduce the amount of energy subject to the Market Power Mitigation Agreement rebate by the transfer of effective control of certain of its generating facilities to other market participants. As OPG transfers effective control of facilities and meets certain milestones, it can apply to the OEB for an order determining that the transactions represent the transfer of effective control and thereby reduce a portion of the Market Power Mitigation Agreement rebate obligation.

In May 2001, OPG completed the agreement to lease its Bruce nuclear generating stations to Bruce Power and in May 2002, OPG completed the sale of four hydroelectric generating stations located on the Mississagi River to the Mississagi Power Trust. In April 2003, in response to applications filed with the OEB, the OEB ruled that OPG had transferred effective control of the Bruce nuclear generating stations and the Mississagi River stations. Accordingly, the OEB agreed to a reduction in the amount of energy subject to the rebate mechanism. The approval of these applications reduced volumes subject to the Market Power Mitigation Agreement rebate for the twelve-month settlement period ended April 30, 2003 from 101.8 TWh to 81.4 TWh. This reduction in the amount of energy subject to the rebate mechanism also applies to the balance of the rebate obligation period. These approvals do not affect the rebate provided to customers under the Business Protection Plan.

In accordance with the Market Power Mitigation Agreement, the rebate is calculated after taking into account the amount of energy sales subject to the rebate mechanism for only those generating stations that OPG continues to control. Since the average hourly spot price during the nine months ended September 30, 2003 has exceeded the 3.8¢/kWh revenue cap, OPG recorded $1,266 million as a Market Power Mitigation Agreement rebate for that period. At September 30, 2003, the Market Power Mitigation Agreement rebate payable was $273 million, which represents the rebate for the period May 1, 2003 to September 30, 2003.

Volume

Electricity sales volumes for the third quarter of 2003 were 27.0 TWh compared to 28.9 TWh for the third quarter of 2002. The decrease in volume was mainly due to lower demand resulting from the cooler summer weather compared to last year, higher planned and forced outage days at OPG's Pickering B nuclear generating station and the impact of the August 14, 2003 blackout.

For the nine month period ended September 30, 2003, electricity sales were 82.1 TWh compared to 95.2 TWh for the same period last year. The decrease in volume was due to the completion of the agreement to purchase and resell electricity produced by the Bruce nuclear generating stations from Bruce Power, and lower production from OPG's generating stations. OPG purchased and resold 6.8 TWh of electricity from Bruce Power between January 1, 2002 and May 1, 2002. The decrease in generation was due in part to the impact on hydroelectric production of significantly lower water levels. Less water flowed into the system during the 2003 spring freshet (water produced from melting snow) due to a lack of rain and lower than normal snowfall. Generation was further reduced compared to last year due to the impact of higher planned and forced outage days at OPG's Pickering B nuclear generating station. OPG's Darlington nuclear generating station continued to perform well, with a net capacity factor of 90 per cent during the nine months ended September 30, 2003, compared to 91 per cent for the same period last year. Fossil production was increased to partially offset the impact of lower hydroelectric and nuclear generation.

	Three Months Ended September 30		Nine Months Ended September 30	
	2003	**2002**	**2003**	**2002**
Total Energy Available for the Generation Segment (TWh)				
Production:				
Nuclear	**10.2**	10.9	**29.2**	32.2
Fossil	**9.4**	10.6	**30.4**	28.7
Hydroelectric	**7.4**	7.4	**22.5**	26.8
Total production	**27.0**	28.9	**82.1**	87.7
Power purchased	**-**	-	**-**	7.4
Other	**-**	-	**-**	0.1
Total Energy Available for the Generation Segment	**27.0**	28.9	**82.1**	95.2

Fuel and Power Purchases

Fuel expense for the third quarter of 2003 was $383 million compared to $412 million for the same period in 2002, a decrease of $29 million. The decrease in fuel costs was primarily due to the lower production at the fossil-fueled generating stations, partially offset by higher costs for oil and natural gas fuel used for fossil generation.

Fuel expense for the nine month period ended September 30, 2003 was $1,265 million compared to $1,147 million for the same period last year, an increase of $118 million. The increase was primarily due to higher costs for coal, oil and natural gas and increased production from fossil stations, partially offset by a decrease in the Gross Revenue Charge ("GRC") resulting from lower hydroelectric production. GRC payments are based on the gross revenue derived from the annual generation of electricity from the hydroelectric generating stations and are dependent on both electricity prices and hydroelectric production. For 2003, gross revenue is calculated based on a fixed electricity price of $40/MWh under the regulations of the *Electricity Act,* 1998.

There were no Generation segment power purchases during the nine month period ended September 30, 2003. Subsequent to market opening, OPG no longer has a requirement to purchase electricity from Bruce Power or a requirement to purchase electricity to meet Ontario market demand. For the nine month period ended September 30, 2002, power purchased was $290 million based on purchases of 7.4 TWh, primarily from Bruce Power.

Operations, Maintenance and Administration

Operations, maintenance and administration ("OM&A") expenses, excluding expenses related to the Pickering A return to service initiative, were $484 million for the three months ended September 30, 2003 compared to $457 million for the same period in 2002, an increase of $27 million. The increase was mainly due to a one-time reduction in expenses of $24 million in 2002 resulting from the Worker's Safety and Insurance Board ("WSIB") assuming the liabilities with respect to OPG's existing and future worker's compensation claims in exchange for a cash payment.

OM&A expenses, excluding the Pickering A return to service initiative, were $1,535 million for the nine months ended September 30, 2003 compared to $1,440 million for the same period in 2002, an increase of $95 million. Increases in the scope and extent of planned outage work and improvements for generating stations in 2003 contributed to an increase in expenses of $109 million. In addition, the WSIB settlement in 2002 resulted in a one-time reduction in expenses of $24 million last year. The impact of these increases was partially offset by other reductions in expenses of $38 million, including savings related to restructuring.

Pickering A Return To Service

OM&A expenses related to the Pickering A return to service initiative were $50 million for the third quarter of 2003 compared to $112 million for the same period in 2002, a decrease of $62 million. For the nine months ended September 30, 2003, expenses for the Pickering A return to service initiative were $220 million compared to $307 million for the same period last year, a decrease of $87 million. The decrease was primarily due to a reduction in the level of construction activities in 2003 as work on the first unit was completed and efforts were focused on testing and commissioning.

Depreciation and amortization

Depreciation and amortization expense for the three months ended September 30, 2003 and 2002 was $118 million. Depreciation and amortization expense for the nine months ended September 30, 2003 was $340 million compared to $343 million for the same period in 2002, a decrease of $3 million.

Accretion

Accretion arises because liabilities for fixed asset removal and nuclear waste management are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time and the effect of inflation on cost estimates. Accretion expense for the third quarter 2003 was $107 million compared with $106 million for the same period in 2002. Accretion expense was $318 million for the nine months ended September 30, 2003 compared to $321 million for the same period last year.

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

Earnings on the nuclear fixed asset removal and nuclear waste management funds for the three months ended September 30, 2003 were $74 million compared to $60 million for the same period last year, an increase of $14 million. Earnings on the nuclear fixed asset removal and nuclear waste management funds for the nine months ended September 30, 2003 were $188 million compared to $178 million for the same period in 2002, an increase of $10 million. The increase in earnings for both the three and nine month periods compared to last year was primarily due to additional interest earned on the receivable from the Ontario Electricity Financial Corporation ("OEFC") upon finalization of the Ontario Nuclear Funds Agreement ("ONFA").

Prior to the third quarter of 2003, OPG reported a revalorization expense that was comprised of accretion expense, net of the interest earned on the receivable from the OEFC and earnings on the nuclear fixed asset removal and nuclear waste management funds. Beginning in the third quarter of 2003, earnings on the funds and accretion expense are disclosed separately. Comparable amounts for 2002 have been reclassified.

Operating Licences

In June 2003, the Canadian Nuclear Safety Commission announced its decision to renew the operating licences of OPG's Pickering A and Pickering B nuclear generating stations. The licence for Pickering B is a five year operating licence, ending June 30, 2008. The Pickering A operating licence is for two years, ending June 30, 2005. OPG's Darlington nuclear station was previously granted its five-year licence in February 2003.

Generating Capacity

In August 2003, Ontario's Energy Minister announced that the government was proceeding with a study for the expansion of the Sir Adam Beck Generating Station near Niagara Falls. The study is expected to be completed by March 2004. OPG is also reviewing its analysis with respect to an underground tunnel from above Niagara Falls to the existing Sir Adam Beck facility to increase electricity output at the existing Beck generating station. In addition, OPG has entered into a partnership with TransCanada Energy Ltd. and is examining the development of a 550 MW gas-fired, combined cycle, co-generation station on the site of the former R. L. Hearn generating station, near downtown Toronto.

Following the results of the recent provincial election, OPG awaits further shareholder direction on these initiatives.

Energy Marketing Segment

Since market opening in May 2002, OPG has transacted with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities ranging from one day to one year. These activities relate primarily to physical energy that is purchased and sold at the Ontario border, the sale of financial risk management products and sales of energy-related products and services to meet customers' needs for energy solutions. Prior to market opening, OPG's energy marketing activity was not a reportable business segment. Accordingly, the comparative amounts for the nine month period ended September 30, 2002 reflect only the activities from May 1, 2002 to September 30, 2002.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2003**	**2002**	**2003**	**2002**
Revenue, net of power purchases	**13**	31	**55**	32
Operations, maintenance and administration	**2**	1	**6**	3
Operating income	**11**	30	**49**	29

Revenue

Revenue for the third quarter of 2003 was $13 million compared to $31 million for the same period last year. Lower volatility in the electricity market in 2003, as a result of cooler summer temperatures, limited the opportunities for short-term trading activities.

For the nine months ended September 30, 2003, revenue was $55 million compared to $32 million for the same period in 2002. The increase reflected a nine month period of operations in 2003 compared to five months in 2002, subsequent to market opening in May 2002.

Interconnected purchases and sales (including those to be physically settled) and mark-to-market gains and losses (realized and unrealized) on energy trading contracts are disclosed on a net basis in the consolidated statements of income. On a gross basis, revenue and power purchases for the three and nine month periods ended September 30, 2003 would have been $50 million and $141 million higher respectively, with no impact on net income.

Non-Energy and Other

(millions of dollars)	Three Months Ended September 30 2003	2002	Nine Months Ended September 30 2003	2002
Revenue	**68**	77	**226**	240
Operations, maintenance and administration	**14**	11	**38**	43
Depreciation and amortization	**27**	24	**84**	80
Property and capital taxes	**3**	3	**9**	9
Loss on transition rate option contracts	**-**	-	**-**	210
Operating income (loss) before restructuring	**24**	39	**95**	(102)
Restructuring	**-**	12	**-**	222
Operating income (loss)	**24**	27	**95**	(324)
Other income	**17**	11	**58**	117
Net interest expense	**39**	36	**97**	114
Income (loss) before income taxes	**2**	2	**56**	(321)

Revenue

Non-energy revenue primarily consists of lease and other revenue derived under the lease agreement with Bruce Power. Under this agreement, the Company leased its Bruce A and Bruce B nuclear generating stations until 2018, with options to renew for up to another 25 years. Non-energy revenue for the third quarter of 2003 was $68 million compared to $77 million for the same period in 2002. Non-energy revenue for the nine months ended September 30, 2003 was $226 million compared to $240 million for the same period last year. The decrease in revenue for both the three and nine month periods was mainly due to lower revenue from engineering services and the elimination of interest income related to the $225 million note receivable from Bruce Power, upon payment of the amount outstanding in February 2003.

Loss on Transition Rate Options

Under a Government regulation known as Transition – Generation Corporation Designated Rate Options ("TRO"), OPG is required to provide transitional price relief upon market opening to certain power customers up to four years based on the consumption and average price paid by each customer during a reference period of July 1, 1999 to June 30, 2000. The maximum anticipated volume subject to the transitional price relief is approximately 5.4 TWh in the first year after market opening, 3.6 TWh in the second year and 1.8 TWh in each of the third and fourth years. The maximum length of the program is four years, with the possibility that it will expire after only two years if certain decontrol targets are met.

A provision of $210 million on the TRO contracts was recorded in the first quarter of 2002 based on the estimated future loss on these contracts. The provision was determined at that time using management's best estimates of the forward price curve for electricity, wholesale electricity market fees, impact of decontrol on these contracts, interruptions of volume, and the recovery of Market Power Mitigation Agreement rebates. These estimates are subject to measurement uncertainty. During the three and nine month periods ended September 30, 2003, $16 million and $58 million respectively were charged against the provision and included in generation revenue. Since market opening in May 2002, $124 million has been charged against the provision and included in revenue.

The provision for the TRO contracts was estimated based on meeting decontrol targets within three years of market opening. Depending on the status of decontrol initiatives, there is a potential for a charge of approximately $35 million related to the fourth year of the TRO contracts.

Restructuring Costs

In 2001, OPG approved a restructuring plan designed to improve OPG's future cost competitiveness. Restructuring charges are related to an anticipated reduction in the workforce over a three to four year period. As at September 30, 2003, OPG had approved severance packages for approximately 1,400 employees. A restructuring charge of $12 million was recorded during the three months ended September 30, 2002 and $222 million was recorded during the nine months ended September 30, 2002. There were no restructuring charges recorded during the first nine months of 2003.

Other Income

Other income was $17 million for the three months ended September 30, 2003 compared to $11 million for the same period in 2002. In the third quarter of 2003, OPG realized gains of $17 million from the sale of certain long-term investments in the Company's nuclear fixed asset removal and nuclear waste management funds. During the third quarter of 2002, OPG completed the sale of the Nuclear Safety Analysis Division and recorded a pre-tax gain of $11 million.

For the nine month period ended September 30, 2003, other income was $58 million compared to $117 million for the same period in 2002, a decrease of $59 million. OPG recorded total gains of $58 million for the nine month period from the sale of long-term investments. During the nine months ended September 30, 2002, OPG recorded pre-tax gains of $99 million from the sale of four hydroelectric generating stations located on the Mississagi River, $11 million from the sale of the Nuclear Safety Analysis Division and $7 million from the sale of OPG's investments in New Horizon Systems Solutions and Kinectrics Inc.

Income Tax

Under the *Electricity Act, 1998,* OPG is responsible for making payments in lieu of federal and provincial corporate income and capital taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), and are modified by regulations made under the *Electricity Act*, *1998*.

For the third quarter of 2003, the effective income tax rate was 42.2 per cent compared to an effective income tax rate of 41.1 per cent for the same period last year. The increase in the effective income tax rate was due in part to the impact of Large Corporations Tax (LCT), which is not dependent on earnings and represented a higher percentage of pre-tax earnings in the third quarter of 2003 compared to last year. This increase was partially offset by higher temporary deductions in 2003 that are taxed at a lower future tax rate.

For the nine months ended in September 30, 2003, the effective income tax rate was 40.8 per cent compared to an effective income tax rate of 48.7 per cent in 2002. The decrease in the effective income tax rate was primarily due to the LCT, which is not dependent on earnings and represented a lower percentage of pre-tax earnings in 2002.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow used in operating activities in the third quarter of 2003 was $642 million compared to cash flow provided by operating activities of $446 million in the third quarter of 2002, a decrease of $1,088 million. The decrease in cash flow was primarily due to payment of the Market Power Mitigation Agreement rebate of $806 million in August 2003, a contribution of $41 million to the pension fund, and other changes in working capital.

Cash flow used in operating activities for the nine months ended September 30, 2003 was $74 million compared to cash flow provided by operating activities of $534 million for the nine months ended September 30, 2002, a decrease of $608 million. During the nine months ended September 30, 2003, OPG paid rebates to the IMO of $1,565 million, contributed $121 million to the pension fund and increased contributions to the nuclear fixed asset removal and nuclear waste management funds by $111 million compared to the same period last year. These uses of cash were partially offset by higher energy prices, proceeds from the payment of the $225 million receivable from Bruce Power and other changes in working capital.

Electricity prices exhibit seasonal variations related to changes in demand. Prices are expected to be 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. Although the Market Power Mitigation Agreement rebate and the Company's hedging strategies significantly reduce the impact of the seasonal price fluctuations on the Company's results from operations, there continues to be significant volatility in earnings resulting from fluctuations in prices related to weather and other factors such as natural gas prices.

OPG continues to invest in plant and technologies to improve operating efficiencies, increase generating capacity of its existing plant and maintain and improve service, reliability, safety and environmental performance. Capital expenditures during the third quarter of 2003 were $139 million compared with $209 million during the third quarter of 2002. Capital expenditures during the nine months ended September 30, 2003 were $459 million compared with $575 million during the same period last year. The decrease was primarily due to lower expenditures on the Pickering A return to service initiative due to a reduction in the level of construction activities in 2003, and the completion of certain major projects.

OPG made a contribution of $41 million to the pension plan during the third quarter of 2003 and $121 million during the nine months ended September 30, 2003. OPG did not contribute to the pension plan in the same periods in 2002.

The nuclear fixed asset removal and nuclear waste management funds increased by $528 million during the nine months ended September 30, 2003 compared to $407 million during the same period last year. This increase was due to the timing of contributions and higher income earned on investments. Year-to-date, OPG has contributed approximately $340 million to the nuclear fixed asset removal and nuclear waste management funds. OPG is required to contribute $113 million in the fourth quarter of 2003.

In July 2003, OPG and the Province of Ontario (the "Province") completed arrangements pursuant to ONFA, which required segregated funds to be established in custodial accounts for ONFA to take effect. To comply with ONFA, OPG transferred the majority of the assets in its existing nuclear fixed asset removal and nuclear waste management funds to new segregated funds. In addition, the receivable due from the OEFC of $3.1 billion was transferred into the segregated funds in the form of $1.2 billion paid in cash and an interest bearing note of approximately $1.9 billion.

Effective as at July 31, 2003, the Province issued a guarantee to the Canadian Nuclear and Safety Commission ("CNSC"), on behalf of OPG, for approximately $1.51 billion. The guarantee, taken together with the establishment of the new segregated funds, were in satisfaction of OPG's nuclear licencing requirements with the CNSC. OPG pays the Province an annual guarantee fee of 0.5 per cent of the amount guaranteed by the Province.

The Company paid dividends to the Province of $17 million during the nine months ended September 30, 2003 compared with $134 million for the same period last year. The amount paid in 2002 reflected a dividend related to proceeds received from the decontrol of the Bruce nuclear generating stations. Dividends are declared and paid to achieve an effective 35 per cent pay-out based on annual net income.

In February 2003, the Company reached an agreement with the OEFC to defer payment on $700 million principal amount of senior notes maturing in 2003 and 2004 by extending the maturity dates by two years. The interest rates remain unchanged. The notes deferred and the new maturities are as follows:

Principal Amount of Senior Notes *(millions of dollars)*	Maturity Prior to Deferral	New Maturity
200	2003	2005
100	2004	2006
300	2004	2006
100	2004	2006

In March 2003, OPG renewed its $1,000 million revolving short-term committed credit facility. The credit facility has a revolving 364-day term, which can be extended for a two-year term. Notes issued under the Company's Commercial Paper ("CP") program are supported by this credit facility. At September 30, 2003, OPG had $10 million outstanding under the CP program.

In October 2003, OPG entered into a revolving securitization agreement with an independent trust. Under this agreement, the Company has sold an undivided interest in certain trade receivables generated in the normal course of business. The initial net cash proceeds from this transaction were $300 million that will be used by OPG in the operation of its business.

Under the terms of the original operating lease agreement with Bruce Power, a $225 million note receivable was payable to OPG in two installments of $112.5 million, no later than four and six years from the date the transaction was completed. In February 2003, British Energy plc. disposed of its entire 82.4 per cent interest in Bruce Power. Upon closing of this transaction, the $225 million note receivable from Bruce Power was paid to OPG. Under ONFA, proceeds from the note are to be applied towards OPG's funding requirements with respect to the nuclear fixed asset removal and nuclear waste management liabilities by March 2008. Also, upon closing, lease payments commenced to be paid monthly. Minimum annual payments under the lease for 2004 to 2008 will be $190 million, subject to limited exceptions. The remaining terms of the operating lease agreement remain substantially unchanged.

Certain Energy Marketing agreements specify that additional collateral in the form of letters of credit or cash may become necessary under certain conditions. Additional collateral may become necessary if OPG's debt rating were to decline and/or if market prices, relative to the contract prices, were to increase. OPG is also required to post collateral with Local Distribution Companies ("LDC's") as prescribed by the OEB's Retail Settlement Code. The amount of collateral required by LDCs varies depending on the size of OPG's customers embedded within a LDC franchise area. At September 30, 2003, there were approximately $142 million of letters of credit issued in support of the supplementary pension plan and for the collateral requirements with LDC's.

PICKERING A RETURN TO SERVICE

OPG has completed its testing and commissioning of the safety and environmental upgrades and other refurbishment work that were required to complete the return to service of Unit 4 at the Pickering A nuclear generating station. On September 25, 2003, OPG declared Unit 4 to be commercially available and informed the Independent Electricity Market Operator that the unit was available for dispatch into the Ontario market.

OPG is continuing to focus on the engineering, planning and assessing for the return to service of the second unit. The cost and schedule to return this unit to service are under review and will be estimated, taking into account OPG's experience associated with returning Unit 4 to service. The detailed schedule and cost estimate are expected to be complete by early 2004.

Cumulative life-to-date expenditures on completing the return to service for Unit 4 and the common operating systems for the station totaled $1,255 million through the end of September 2003. The total cumulative expenditures on all four units to the end of September 2003 were $1,502 million.

On May 30, 2003, Ontario's Minister of Energy announced that a three-member panel had been appointed to review the Pickering A return to service project. The review will include the following:

- Determine the reasons and reasonableness of the changes in the schedule and return to service dates;
- Determine the reasons and reasonableness of cost estimates and cost increases;
- Review the financial reporting for project costs;
- Make recommendations to the Minister on means of improving the management of the project to restore the Pickering A generating station to full operation, including measures to ensure the cost-effective and timely completion of the project;
- Make such further review, determination or recommendation as the Minister may require.

The panel is to provide a full report to the Minister by December 31, 2003.

RISK MANAGEMENT

OPG's portfolio of generation assets and electricity trading and marketing operations are subject to inherent risks, including financial, operational, regulatory and strategic risks. To manage these risks, OPG has implemented an enterprise-wide risk management framework which includes governance policies, organizational structures, and risk measurement and monitoring processes.

Commodity Price Risk

Commodity price risk is the risk that changes in the market price of electricity or of the fuels used to produce electricity, from fossil and hydroelectric facilities, will adversely impact OPG's earnings and cash flow from operations. A variable portion of both OPG's electricity production and overall fuel requirements are exposed to fluctuating spot market prices. To manage this risk, the Company maintains a balance between the commodity price risk inherent in its electricity production and plant fuel portfolios.

Open trading positions are subject to measurement against value at risk or VaR limits, which measure the potential change in the portfolio's market value due to price volatility over a one-day holding period, with a 95 per cent confidence interval. VaR utilization ranged between $0.3 million to $0.6 million during the three months ended September 30, 2003. VaR utilization ranged between $0.3 million to $1.6 million during the nine months ended September 30, 2003.

In addition to fixed price contracts for fossil and nuclear fuels, the Company employs derivative instruments to hedge its commodity price risk. The percentage of OPG's generation and fuel requirements hedged over the remainder of 2003 and the next two years is shown below:

	2003	2004	2005
Estimated generation output hedged [1]	91%	80%	78%
Estimated fuel requirements hedged [2]	97%	86%	72%

[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 its Market Power Mitigation Agreement rebate and transition rate option contracts.

[2] Represents the approximate portion of megawatt hours of expected generation production 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. Fuel in inventory is included. The percentage hedged by fuel type varies considerably and therefore a change in circumstances could have a significant impact on OPG's overall position.

Credit Risk

Credit risk is the potential for loss arising from the failure of counterparties to perform their contractual obligations. Subsequent to market opening, the majority of OPG's revenues are derived from sales through the IMO-administered spot market. OPG also derives revenue from several other sources including the sale of financial risk management products to third parties.

OPG's credit exposure is concentrated in the physical electricity market with the IMO. Credit exposure to the IMO fluctuates based on timing and is reduced each month upon settlement of the accounts. Credit exposure to the IMO peaked at $1,134 million during the nine months ended September 30, 2003. OPG's management believes that the IMO is an acceptable credit risk due to its primary role in the Ontario market. The IMO manages its own credit risk and its ability to pay generators by mandating that all registered IMO spot market participants meet specific IMO standards for creditworthiness and collateralization. OPG also measures its credit concentrations with counterparties. OPG management believes these are within acceptable limits and does not anticipate any material effect on its results of operations or cash flows arising from potential defaults.

The following table provides information on credit risk from energy sales and trading activities as at September 30, 2003.

(millions of dollars)			Potential Exposure [2] for 10 Largest Counterparties	
Credit Rating [1]	Number of Counterparties	Potential Exposure [2]	Number of Counterparties	Counterparty Exposure
AAA to AA-	10	40	1	18
A+ to A-	39	197	4	139
BBB+ to BBB-	71	127	3	40
BB+ to BB-	27	40	1	12
B+ to B-	24	9	-	-
	171	413	9	209
IMO	1	420	1	420
Total	172	833	10	629

[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] Potential exposure represents OPG's assessment of the maximum exposure over the life of each transaction at 95 per cent confidence.

For all other counterparties, OPG's contracts allow for active collateral management to mitigate credit exposures. The contracts provide for a counterparty to post letters of credit or cash for exposure in excess of the established threshold. This could happen as a result of market moves or upon the occurrence of credit-related events. The threshold amount represents credit limits established in accordance with the corporate credit policy. Inability to post collateral is sufficient cause to terminate a contract and liquidate all positions.

Coal-fired Generating Stations

The recently elected government has made statements with respect to the phase out of coal-fired generating stations. The Company will continue to evaluate the impact of a phase out of coal-fired generating stations on its operations as further direction from the shareholder becomes available.

OPG is required by regulation to cease burning coal at its Lakeview generating station by April 2005. The Company has given notice to the IMO of the Company's intention to deregister the Lakeview generating station at that time.

SUPPLEMENTAL EARNINGS MEASURES

In addition to providing earnings measures in accordance with Canadian generally accepted accounting principles, OPG presents certain supplemental earnings measures. These are operating income (loss) before restructuring and operating income (loss). These measures do not have any standardized meaning prescribed by Canadian generally accepted accounting principles and are, therefore, unlikely to be comparable to similar measures presented by other companies. These measures are provided to assist readers of the financial statements in assessing income performance from ongoing operations.

FORWARD-LOOKING STATEMENTS

This document 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 a current or historical fact is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could" and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression will not, however, mean that a statement is not a forward-looking statement.

All forward-looking statements involve inherent assumptions, risks and uncertainties and, therefore, could be wrong to a material degree. In particular, forward-looking statements contain assumptions such as those relating to OPG's nuclear recovery plan, fuel costs and availability, nuclear decommissioning and waste management, spot market electricity prices, the on-going evolution of the Ontario electricity industry, market power mitigation, environmental and other regulatory requirements, and the weather. Accordingly, undue reliance should not be placed on any forward-looking statement.

OPG has neither any intention nor any obligation to update or otherwise revise any forward-looking statement, whether as a result of new information, future developments or otherwise.

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CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars except where noted)	Three Months Ended September 30 2003	Three Months Ended September 30 2002	Nine Months Ended September 30 2003	Nine Months Ended September 30 2002
Revenues	**1,224**	1,612	**3,950**	4,432
Fuel	**383**	412	**1,265**	1,147
Power purchased	**-**	-	**-**	290
Gross Margin	**841**	1,200	**2,685**	2,995
Operating expenses				
Operations, maintenance and administration	**550**	581	**1,799**	1,793
Depreciation and amortization *(note 9)*	**145**	142	**424**	423
Accretion on fixed asset removal and nuclear waste management liabilities	**107**	106	**318**	321
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(74)**	(60)	**(188)**	(178)
Property and capital taxes	**27**	29	**82**	88
Loss on transition rate option contracts *(note 10)*	**-**	-	**-**	210
	755	798	**2,435**	2,657
Operating income before restructuring	**86**	402	**250**	338
Restructuring *(note 11)*	**-**	12	**-**	222
Operating income	**86**	390	**250**	116
Other income *(note 13)*	**17**	11	**58**	117
Net interest expense	**39**	36	**97**	114
	22	25	**39**	(3)
Income before income taxes	**64**	365	**211**	119
Income taxes (recoveries)				
Current	**5**	131	**65**	86
Future	**22**	19	**21**	(28)
	27	150	**86**	58
Net income	**37**	215	**125**	61
Basic and diluted earnings per common share *(dollars)*	**0.14**	0.84	**0.49**	0.24
Common shares outstanding *(millions)*	**256.3**	256.3	**256.3**	256.3

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (UNAUDITED)

Nine Months Ended September 30 *(millions of dollars)*	2003	2002
Retained earnings, beginning of period	**257**	344
Net income	**125**	61
Dividends	**(17)**	(134)
Retained earnings, end of period	**365**	271

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(millions of dollars)	Three Months Ended September 30 2003	Three Months Ended September 30 2002	Nine Months Ended September 30 2003	Nine Months Ended September 30 2002
Operating activities				
Net income	**37**	215	**125**	61
Adjust for non-cash items:				
Depreciation and amortization *(note 9)*	**145**	142	**424**	423
Accretion	**107**	106	**318**	321
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(74)**	(60)	**(188)**	(178)
Pension	**(1)**	(1)	**(4)**	3
Other post employment benefits	**33**	21	**101**	96
Future income taxes	**22**	19	**21**	(28)
Provision for restructuring *(note 11)*	**-**	12	**-**	222
Transition rate option contracts *(note 10)*	**(16)**	(25)	**(58)**	167
Gain on sale of investments	**(17)**	(11)	**(58)**	(18)
Gain on sale of decontrol fixed assets	**-**	-	**-**	(99)
Mark to market on energy contracts	**1**	6	**(5)**	4
Provision for used nuclear fuel	**5**	7	**15**	29
Other	**1**	5	**1**	11
	243	436	**692**	1,014
Contributions to nuclear fixed asset removal and nuclear waste management funds	**(82)**	(107)	**(340)**	(229)
Expenditures on fixed asset removal and nuclear waste management	**(17)**	(17)	**(48)**	(69)
Contributions to pension fund	**(41)**	-	**(121)**	-
Expenditures on other post employment benefits	**(15)**	(14)	**(38)**	(37)
Expenditures on restructuring *(note 11)*	**(10)**	(23)	**(54)**	(95)
Net changes to other long-term assets and liabilities	**(29)**	(78)	**(70)**	(158)
Market Power Mitigation Agreement rebate payment	**(806)**	-	**(1,565)**	-
Changes in non-cash working capital balances *(note 14)*	**115**	249	**1,470**	108
Cash flow provided by (used in) operating activities	**(642)**	446	**(74)**	534
Investing activities				
Net proceeds from short-term investments	**-**	-	**-**	39
Proceeds on sale of decontrol fixed assets	**-**	-	**1**	342
Cash proceeds from sale of investments	**17**	15	**58**	29
Purchases of fixed assets	**(139)**	(209)	**(459)**	(575)
Cash flow (used in) investing activities	**(122)**	(194)	**(400)**	(165)
Financing activities				
Issuance of long-term debt *(note 5)*	**-**	138	**52**	138
Repayment of long-term debt	**-**	(1)	**-**	(1)
Dividends paid	**-**	-	**(17)**	(134)
Short-term notes issued	**547**	35	**937**	235
Short-term notes repaid	**(642)**	(35)	**(1,109)**	(235)
Cash flow provided by (used in) financing activities	**(95)**	137	**(137)**	3
Net increase (decrease) in cash and cash equivalents	**(859)**	389	**(611)**	372
Cash and cash equivalents, beginning of period	**872**	(17)	**624**	-
Cash and cash equivalents, end of period	**13**	372	**13**	372

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(millions of dollars)	**September 30 2003**	**December 31 2002**
Assets		
Current assets		
Cash and cash equivalents	**13**	624
Accounts receivable	**580**	736
Note receivable *(note 7)*	**-**	225
Income taxes recoverable	**26**	80
Fuel inventory	**559**	514
Materials and supplies	**71**	80
	1,249	2,259
Fixed assets		
Property, plant and equipment	**15,416**	15,014
Less: accumulated depreciation	**2,515**	2,068
	12,901	12,946
Other long-term assets		
Deferred pension asset	**430**	305
Nuclear fixed asset removal and nuclear waste management funds *(note 6)*	**5,065**	4,537
Long-term materials and supplies	**224**	193
Long-term accounts receivable and other assets	**73**	59
	5,792	5,094
	19,942	20,299

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(millions of dollars)	**September 30 2003**	**December 31 2002**
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(note 10)*	**978**	1,235
Market Power Mitigation Agreement rebate payable *(note 3)*	**273**	572
Short-term notes payable *(note 4)*	**10**	182
Deferred revenue due within one year	**12**	12
Long-term debt due within one year *(note 5)*	**5**	5
	1,278	2,006
Long-term debt *(note 5)*	**3,404**	3,352
Other long-term liabilities		
Fixed asset removal and nuclear waste management *(note 6)*	**8,064**	7,853
Other post employment benefits	**1,021**	958
Long-term accounts payable and accrued charges *(note 10)*	**246**	321
Deferred revenue	**170**	179
Future income taxes	**268**	247
	9,769	9,558
Shareholder's equity		
Common shares	**5,126**	5,126
Retained earnings	**365**	257
	5,491	5,383
	19,942	20,299

Commitments and Contingencies *(note 15)*

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2003

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. However, these financial statements do not contain all the disclosures required by Canadian generally accepted accounting principles for annual financial statements. Accordingly, the interim consolidated financial statements should be read in conjunction with the most recently prepared annual consolidated financial statements for the year ended December 31, 2002.

Certain of the 2002 comparative amounts have been reclassified from financial statements previously presented to conform to the 2003 financial statement presentation.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

The Ontario Nuclear Funds Agreement ("ONFA") between OPG and the Province of Ontario (the "Province") requires segregated funds to be established in custodial accounts for funding the nuclear fixed asset removal and nuclear waste management liabilities. The segregated funds are invested in debt and equity securities which are treated as long-term investments and are accounted for at amortized cost. The segregated funds are reported as nuclear fixed asset removal and nuclear waste management funds in the consolidated balance sheets. Realized gains and losses on the segregated funds are recorded in earnings on nuclear fixed asset removal and nuclear waste management funds in the consolidated statements of income.

Following the establishment of the segregated funds in July 2003, the amount receivable from the Ontario Electricity Financial Corporation ("OEFC") is held in a custodial account in the form of an interest-bearing note and is included in the investments reported in the nuclear fixed asset removal and nuclear waste management funds. Previously, the receivable from the OEFC had been offset against fixed asset removal and nuclear waste management liabilities. Amounts as at December 31, 2002 have been reclassified to reflect this change.

Accretion on Fixed Asset Removal and Nuclear Waste Management Liabilities

Accretion arises because liabilities for fixed asset removal and nuclear waste management are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time and the effect of inflation on cost estimates.

Prior to the third quarter of 2003, OPG reported a revalorization charge that was comprised of accretion expense on the fixed asset removal and nuclear waste management liabilities, net of the earnings on the nuclear fixed asset removal and nuclear waste management funds and interest earned on the receivable from the OEFC. Beginning in the third quarter of 2003, the accretion expense and earnings on the nuclear fixed asset removal and nuclear waste management funds, including interest earned on the receivable from the OEFC, are disclosed separately in the consolidated statements of income. Prior periods were reclassified to reflect this change.

3. MARKET POWER MITIGATION AGREEMENT REBATE

Under OPG's generating licence, subject to regulatory approval, the Company has the ability to reduce the amount of energy subject to the Market Power Mitigation Agreement rebate by the transfer of effective control of certain of its generating facilities to other market participants. As OPG transfers effective control of facilities and meets certain milestones, it can apply to the Ontario Energy Board ("OEB") for an order determining that the transactions represent the transfer of effective control and thereby reduce a portion of the Market Power Mitigation Agreement rebate obligation.

In May 2001, OPG completed the agreement to lease its Bruce nuclear generating stations to Bruce Power L.P. ("Bruce Power") and in May 2002, completed the sale of four of its hydroelectric generating stations located on the Mississagi River to Mississagi Power Trust. In April 2003, in response to applications filed with the OEB, the OEB ruled that OPG had transferred effective control of the Bruce nuclear generating stations and the Mississagi River stations. Accordingly, the OEB agreed to a reduction in the amount of energy subject to the rebate. The approval of the applications reduces volumes subject to the Market Power Mitigation Agreement rebate for the twelve-month settlement period ended April 30, 2003 from 101.8 TWh to 81.4 TWh. This reduction in the amount of energy subject to the rebate mechanism also applies to the balance of the rebate obligation period. The reduction in volumes subject to the Market Power Mitigation Agreement rebate does not affect the rebate provided to customers under the Government's Business Protection Plan.

In accordance with the Market Power Mitigation Agreement, the rebate is calculated after taking into account the amount of energy sales subject to the rebate mechanism for only those generating stations that OPG continues to control. Since the average hourly spot price during the third quarter and nine month periods ended September 30, 2003 has exceeded the 3.8¢/kWh revenue cap, OPG provided $192 million and $1,266 million, respectively, as a Market Power Mitigation Agreement rebate (third quarter and nine month period ended September 30, 2002 – $565 million).

The change in the Market Power Mitigation Agreement rebate liability for the nine months ended September 30, 2003 was as follows:

For the nine months ended September 30	**2003**
(millions of dollars)	
Liability, as at December 31, 2002	**572**
Increase to provision during the period	**1,266**
Payments	**(1,565)**
Liability, as at September 30, 2003	**273**

4. SHORT-TERM CREDIT FACILITIES

In March 2003, OPG renewed its $1,000 million revolving short-term committed credit facility. The credit facility has a revolving 364-day term, which can be extended for a two-year term. Notes issued under the Company's Commercial Paper program are supported by this credit facility.

5. LONG-TERM DEBT

Long-term debt consists of the following:

(millions of dollars)	**September 30 2003**	**December 31 2002**
Notes payable to the OEFC	**3,200**	3,200
Capital lease obligations	**20**	19
Share of limited partnership debt	**189**	138
	3,409	3,357
Less: capital lease obligations payable within one year	**5**	5
Long-term debt	**3,404**	3,352

In February 2003, the Company reached an agreement with the OEFC to defer payment on $700 million principal amount of senior notes maturing in 2003 and 2004 by extending the maturity dates by two years. The interest rates remain unchanged. The maturity dates for notes payable to the OEFC are as follows:

		Principal Outstanding *(millions of dollars)*		
Year of Maturity	**Interest Rate (%)**	**Senior Notes**	**Subordinated Notes**	**Total**
2005	5.49	200	-	200
2005	5.71	300	-	300
2006	5.44	100	-	100
2006	5.62	300	-	300
2006	5.94	100	-	100
2006	5.78	300	-	300
2007	5.85	400	-	400
2008	5.90	400	-	400
2009	6.01	350	-	350
2010	6.60	-	375	375
2011	6.65	-	375	375
		2,450	750	3,200

Interest paid during the three months ended September 30, 2003 was $97 million (three months ended September 30, 2002 - $96 million), of which $96 million (three months ended September 30, 2002 - $95 million) relates to interest paid on long-term debt. Interest paid during the nine months ended September 30, 2003 was $195 million (nine months ended September 30, 2002 - $195 million), of which $192 million (nine months ended September 30, 2002 - $192 million) relates to interest paid on long-term debt.

6. 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 2003	December 31 2002
Liability for nuclear waste management	**5,133**	5,020
Liability for nuclear fixed asset removal	**2,797**	2,702
	7,930	7,722
Liability for non-nuclear fixed asset removal	**134**	131
Fixed asset removal and nuclear waste management	**8,064**	7,853

The change in the fixed asset removal and nuclear waste management liability for the nine months ended September 30, 2003 is as follows:

For the nine months ended September 30	2003
(millions of dollars)	
Liability, as at December 31, 2002	**7,853**
Increase in the liability due to accretion	**318**
Provision	**15**
Waste management expenditures	**(48)**
Balance sheet reclassification of expenditures	**(41)**
Amortization of cost estimate changes	**(33)**
Liability, as at September 30, 2003	**8,064**

On July 24, 2003, OPG and the Province completed arrangements pursuant to ONFA, which required the establishment of segregated funds to hold the nuclear fixed asset removal and nuclear waste management funds, for ONFA to take effect. To comply with ONFA, OPG transferred the majority of the assets in its existing nuclear fixed asset removal and nuclear waste management funds to new segregated funds held in custodial accounts. In addition, the receivable due from the OEFC of $3.1 billion was transferred into the segregated funds in the form of $1.2 billion paid in cash and a $1.9 billion interest bearing note receivable.

The nuclear fixed asset removal and nuclear waste management funds consist of the following:

(millions of dollars)	September 30 2003
Decommissioning fund	3,609
Used Fuel fund	1,456
	5,065

Effective as at July 31, 2003, the Province issued a guarantee to the Canadian Nuclear and Safety Commission ("CNSC"), on behalf of OPG, for approximately $1.51 billion. The guarantee, taken together with the establishment of the new segregated custodial funds, were in satisfaction of OPG's nuclear licencing requirements with the CNSC. OPG pays the Province an annual guarantee fee of 0.5 per cent of the amount guaranteed by the Province.

Under ONFA, the Province guarantees OPG's return in the Used Fuel fund at Ontario CPI plus 3.25 per cent ("committed return"). The difference between the committed return on the Used Fuel fund and the actual net return, based on the fair value of fund assets, which includes realized and unrealized returns, is due to or due from the Province. Since OPG accounts for the investments in the funds on an amortized cost basis, the amount due to or due from the Province recorded in the consolidated financial statements is the difference between the committed return and the actual return based on realized returns only. At September 30, 2003, the Used Fuel fund assets included a receivable from the Province of $6 million. If the investments in the Used Fuel fund were accounted for at fair market value in the consolidated financial statements, at September 30, 2003, there would be an amount due from the Province of $1 million.

The fair values and the amortized cost of the securities invested in the segregated funds, which include the Used Fuel and Decommissioning funds, as at September 30, 2003 are as follows:

(millions of dollars)	**Amortized Cost Basis**	**Fair Value**
Cash and cash equivalents	**153**	**153**
Marketable equity securities	**2,467**	**2,473**
Bonds and debentures	**572**	**578**
Receivable from the OEFC	**1,869**	**1,869**
Administrative expense payable	**(2)**	**(2)**
	5,059	**5,071**
Due from Province	**6**	**1**
Total	**5,065**	**5,072**

The bonds and debentures mature according to the following schedule:

At September 30, 2003 *(millions of dollars)*	**Fair Value**
Less than 1 year	**-**
1 - 5 years	**183**
5 - 10 years	**253**
More than 10 years	**142**
Total maturities of debt securities	**578**

The receivable of $1,869 million from the OEFC does not have a specified maturity date.

Under ONFA, OPG is also obligated to fund any shortfall in returns in the Decommissioning fund below 5.75 per cent when the Decommissioning fund is underfunded, as compared to the decommissioning liability. There are currently no amounts owing.

7. DECONTROL AND OTHER INITIATIVES

Bruce Power – Change in Ownership

In May 2001, OPG leased its Bruce A and Bruce B nuclear generating stations to Bruce Power until 2018, with an option to renew for up to another 25 years. In December 2002, British Energy plc. entered into an agreement to dispose of its entire 82.4 per cent interest in Bruce Power. The transaction was completed in February 2003 and a consortium of Canadian companies assumed the lease of the Bruce A and Bruce B nuclear generating stations that were formerly held by British Energy. The Bruce facilities will continue to be operated by Bruce Power. Upon closing of the transaction, the $225 million note receivable was paid to OPG, and lease payments commenced to be paid monthly. Proceeds from the note are to be applied by March 2008 against OPG's funding requirements with respect to the nuclear fixed asset removal and nuclear waste management liabilities. In addition, for 2004 through 2008, minimum payments under the lease are $190 million annually, subject to limited exceptions. The remaining terms of the operating lease agreement remain substantially unchanged.

Other Decontrol Activities and Initiatives

During the provincial election campaign, statements and political platforms referenced OPG's operations. This included statements with respect to decontrol initiatives. OPG awaits shareholder direction with respect to decontrol and other matters.

8. DERIVATIVE FINANCIAL INSTRUMENTS, CREDIT RISK, AND RISK MANAGEMENT INSTRUMENTS

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

Trading activities and liquidity in the Ontario electricity market have been limited as companies are generally entering only into short-term contracts. As a result, forward pricing information for contracts may not accurately represent the cost to enter into these contracts. For Ontario based contracts that are not entered into for hedging purposes, OPG established liquidity reserves against the fair market value of the assets and liabilities equal to the gain or loss on these contracts. These reserves reduced Energy Marketing revenue for the nine months ended September 30, 2003 by $5 million. Contracts outside of Ontario continue to be carried on the balance sheet as assets or liabilities at fair value with changes in fair value recorded in Energy Marketing revenue as gains or losses.

Derivative instruments used for hedging purposes

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

(millions of dollars)	**September 30, 2003**			**December 31, 2002**		
Gain/(loss)	**Notional quantity**	**Terms**	**Fair Value**	**Notional quantity**	**Terms**	**Fair Value**
Electricity derivative instruments	**24 TWh**	**1-4 yrs**	**(61)**	37.9 TWh	1-4 yrs	(144)
Foreign exchange derivative instruments	**$165 US**	**1-4 months**	**(18)**	$179 US	Apr/03	4
Option to purchase emission reduction credits	**3,000,000 tonnes**	**2003-2004**	**-**	6,000,000 tonnes	2003-2004	1

Derivative instruments not used for hedging purposes

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

(millions of dollars)	**September 30, 2003**		**December 31, 2002**	
	Notional quantity	**Fair Value**	**Notional quantity**	**Fair Value**
Commodity derivative instruments				
Assets	**11.1 TWh**	**7**	7.7 TWh	10
Liabilities	**0.7 TWh**	**(6)**	2.9 TWh	(14)
		1		(4)
Ontario market liquidity reserve		**(5)**		(7)
Total		**(4)**		(11)

9. DEPRECIATION AND AMORTIZATION

Depreciation and amortization expense for the three months ended September 30, 2003 and 2002 consists of the following:

For the three months ended September 30	**2003**	**2002**
(millions of dollars)		
Depreciation	**156**	147
Nuclear waste management costs	**1**	1
Change in estimate of the nuclear waste management liability	**(12)**	(6)
	145	142

Depreciation and amortization expense for the nine months ended September 30, 2003 and 2002 consists of the following:

For the nine months ended September 30	2003	2002
(millions of dollars)		
Depreciation	**458**	436
Nuclear waste management costs	**2**	4
Change in estimate of the nuclear waste management liability	**(36)**	(17)
	424	423

10. TRANSITION RATE OPTION CONTRACTS

Under a regulation known as Transition – Generation Corporation Designated Rate Options ("TRO"), OPG is required to provide transitional price relief upon market opening to certain power customers based on the consumption and average price paid by each customer during a reference period from July 1, 1999 to June 30, 2000. The TRO is treated as a hedge of generation revenue. The maximum anticipated volume subject to the transitional price relief is approximately 5.4 TWh in the first year after market opening, 3.6 TWh in the second year and 1.8 TWh in each of the third and fourth years. The maximum length of the program is four years, with the possibility that it will expire after only two years if certain decontrol targets are met.

A provision of $210 million for the TRO contracts was recorded in the first quarter of 2002 related to the anticipated future losses on these contracts. The provision was determined during the first quarter of 2002 using management's best estimates of the forward price curve for electricity, wholesale electricity market fees, impact of decontrol on the contracts, interruptions of volume, and the recovery of Market Power Mitigation Agreement rebates. It is possible that actual results experienced may differ materially from the estimated amounts. The provision will be reduced over the term of the contracts based on volume and will be recorded in revenue.

For the three months ended September 30, 2003, the provision has been reduced by $16 million (2002 - $25 million). For the nine month period ended September 30, 2003, the provision was reduced by $58 million (2002 - $43 million). At September 30, 2003, the current portion of the provision for loss on these contracts was $74 million (December 31, 2002 - $82 million) and was included in accounts payable and accrued charges. The long-term portion of the provision, which was included in long-term accounts payable and accrued charges, was $12 million (December 31, 2002 - $62 million).

The provision for the TRO contracts was estimated based on meeting decontrol targets within three years of market opening. Depending on the status of decontrol initiatives, there is a potential for a charge of approximately $35 million related to the fourth year of the TRO contracts.

11. RESTRUCTURING

In 2001, OPG approved a restructuring plan designed to improve OPG's future competitiveness. The restructuring program relates to an anticipated reduction in the workforce over a three to four year period. Cumulative restructuring charges under the 2001 plan of $289 million included severance costs of $254 million and related pension and other post employment benefit expenses of $35 million. Pension and other post employment benefit expenses, recorded as part of restructuring, are included in the deferred pension asset and other post employment benefits on the balance sheet.

The change in the restructuring liability for severance for the nine months ended September 30, 2003 is as follows:

For the nine months ended September 30	2003
(millions of dollars)	
Liability, as at December 31, 2002	**120**
Payments during the period	**(54)**
Liability, as at September 30, 2003	**66**

During the third quarter of 2002, a restructuring charge for severance of $12 million was recorded and severance payments totaled $23 million. During the nine months ended September 30, 2002, restructuring charges of $222 million were recorded, of which $213 million related to severance and $9 million related to pension and other post employment benefits and expenses. Severance payments during the 9 months ended September 30, 2003 totaled $95 million.

12. BUSINESS SEGMENTS

Segment Income for the three months ended September 30, 2003	Generation	Energy Marketing	Non-Energy and Other	Total
(millions of dollars)				
Revenues	**1,143**	**13**	**68**	**1,224**
Fuel	**383**	**-**	**-**	**383**
Gross margin	**760**	**13**	**68**	**841**
Operations, maintenance and administration	**484**	**2**	**14**	**500**
Pickering A return to service	**50**	**-**	**-**	**50**
Depreciation and amortization	**118**	**-**	**27**	**145**
Accretion on fixed asset removal and nuclear waste management liabilities	**107**	**-**	**-**	**107**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(74)**	**-**	**-**	**(74)**
Property and capital taxes	**24**	**-**	**3**	**27**
Operating income	**51**	**11**	**24**	**86**
Other income	**-**	**-**	**17**	**17**
Net interest expense	**-**	**-**	**39**	**39**
Income before income taxes	**51**	**11**	**2**	**64**

Segment Income for the three months ended September 30, 2002	Generation	Energy Marketing	Non-Energy and Other	Total
(millions of dollars)				
Revenues	1,504	31	77	1,612
Fuel	412	-	-	412
Gross margin	1,092	31	77	1,200
Operations, maintenance and administration	457	1	11	469
Pickering A return to service	112	-	-	112
Depreciation and amortization	118	-	24	142
Accretion on fixed asset removal and nuclear waste management liabilities	106	-	-	106
Earnings on nuclear fixed asset removal and nuclear waste management funds	(60)	-	-	(60)
Property and capital taxes	26	-	3	29
Operating income before restructuring	333	30	39	402
Restructuring	-	-	12	12
Operating income	333	30	27	390
Other income	-	-	11	11
Net interest expense	-	-	36	36
Income before income taxes	333	30	2	365

Segment Income for the nine months ended September 30, 2003	Generation	Energy Marketing	Non-Energy and Other	Total
(millions of dollars)				
Revenues	**3,669**	**55**	**226**	**3,950**
Fuel	**1,265**	**-**	**-**	**1,265**
Gross margin	**2,404**	**55**	**226**	**2,685**
Operations, maintenance and administration	**1,535**	**6**	**38**	**1,579**
Pickering A return to service	**220**	**-**	**-**	**220**
Depreciation and amortization	**340**	**-**	**84**	**424**
Accretion on fixed asset removal and nuclear waste management liabilities	**318**	**-**	**-**	**318**
Earnings on nuclear fixed asset and nuclear waste management funds	**(188)**	**-**	**-**	**(188)**
Property and capital taxes	**73**	**-**	**9**	**82**
Operating income	**106**	**49**	**95**	**250**
Other income	**-**	**-**	**58**	**58**
Net interest expense	**-**	**-**	**97**	**97**
Income before income taxes	**106**	**49**	**56**	**211**

Segment Income for the nine months ended September 30, 2002	Generation	Energy Marketing	Non-Energy and Other	Total
(millions of dollars)				
Revenues	4,160	32	240	4,432
Fuel	1,147	-	-	1,147
Power purchased	290	-	-	290
Gross margin	2,723	32	240	2,995
Operations, maintenance and administration	1,440	3	43	1,486
Pickering A return to service	307	-	-	307
Depreciation and amortization	343	-	80	423
Accretion on fixed asset removal and nuclear waste management liabilities	321	-	-	321
Earnings on nuclear fixed asset removal and nuclear waste management funds	(178)	-	-	(178)
Property and capital taxes	79	-	9	88
Loss on transition rate option contracts	-	-	210	210
Operating income (loss) before restructuring	411	29	(102)	338
Restructuring	-	-	222	222
Operating income (loss)	411	29	(324)	116
Other income	-	-	117	117
Net interest expense	-	-	114	114
Income (loss) before income taxes	411	29	(321)	119

	Generation	Energy Marketing	Non-Energy and Other	Total
Selected Balance Sheet Information				
(millions of dollars)				
September 30, 2003				
Segment property, plant and equipment, net	**11,973**	**-**	**928**	**12,901**
December 31, 2002				
Segment property, plant and equipment, net	12,003	-	943	12,946
Selected Cash Flow Information				
(millions of dollars)				
Three months ended September 30, 2003				
Capital expenditures	**116**	**-**	**23**	**139**
Three months ended September 30, 2002				
Capital expenditures	179	-	30	209

	Generation	Energy Marketing	Non-Energy and Other	Total
Selected Cash Flow Information				
(millions of dollars)				
Nine months ended September 30, 2003				
Capital expenditures	**397**	**-**	**62**	**459**
Nine months ended September 30, 2002				
Capital expenditures	506	-	69	575

13. OTHER INCOME

Other income is comprised of the gain on sales from decontrol activities and other initiatives as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2003	2002	2003	2002
(millions of dollars)				
Sale of long-term investments	**17**	-	**58**	-
Mississagi River generating stations	**-**	**-**	**-**	99
Nuclear Safety Analysis Division	**-**	11	**-**	11
Investment in New Horizon Systems Solutions Inc.	**-**	-	**-**	4
Investment in Kinectrics Inc.	**-**	-	**-**	3
	17	11	**58**	117

14. CHANGES IN NON-CASH WORKING CAPITAL BALANCES

	Three Months Ended September 30		Nine Months Ended September 30	
	2003	2002	2003	2002
(millions of dollars)				
Accounts receivable	**18**	(388)	**156**	201
Note receivable	**-**	-	**225**	-
Income taxes recoverable	**(10)**	143	**54**	66
Fuel inventory	**(88)**	8	**(45)**	(40)
Materials and supplies	**3**	-	**2**	(19)
Market power mitigation agreement rebate	**192**	563	**1,266**	563
Accounts payable and accrued charges	**-**	(77)	**(188)**	(663)
	115	249	**1,470**	108
Supplementary Disclosure				
Income taxes paid	**9**	-	**17**	40

15. GUARANTEES

As part of normal business, OPG and certain subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees, stand-by letters of credit and surety bonds. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes.

OPG has provided limited guarantees in connection with the Brighton Beach financing. If the partnership fails to complete the project or meet certain performance tests by September 30, 2006, OPG may be required to repurchase its proportionate share of the outstanding debt, up to a total of $202 million. OPG is also responsible for contributing its share of equity up to $47 million and up to $13 million of cost overruns as necessary. OPG has also provided guarantees relating to gas transport and other energy-based charges if the commercial operations date is delayed in certain circumstances; and debt service if the energy conversion agreement is terminated, from the date of such termination to the earlier of the entry into a replacement agreement and September 30, 2006.

16. PROVINCIAL ELECTION

A provincial election was called on September 2, 2003. During the election campaign, statements and political platforms referenced OPG's operations and the Ontario electricity sector. Following the October 2, 2003 election, OPG will be discussing these matters with the new government and seeking direction of the shareholder in the near future.

17. SUBSEQUENT EVENT, SALE OF RECEIVABLES

In October 2003, OPG entered into a revolving securitization agreement with an independent trust. Under this agreement, the Company has sold an undivided interest in certain trade receivables generated in the normal course of business. The initial net cash proceeds from this transaction were $300 million that will be used by OPG in the operation of its business.

When the Company sold the receivables, it retained servicing rights and provided limited recourse, which constituted a retained interest in the sold receivables. OPG's incremental expenses relating to the servicing, administration and collection of the receivables are not material. Accordingly, no servicing liability will be recognized in the financial statements.