ONTARIO POWER GENERATION

News
from Ontario Power Generation

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ONTARIO POWER GENERATION REPORTS 2003 SECOND QUARTER EARNINGS

[Toronto]: Ontario Power Generation Inc. ("OPG") today reported its financial and operating results for the second quarter and six months ended June 30, 2003. Net income for the three months ended June 30, 2003 was $12 million or $0.05 per share, compared with $63 million or $0.25 per share for the three months ended June 30, 2002. For the six months ended June 30, 2003, net income was $88 million or $0.34 per share compared to a loss of $154 million or $0.60 per share for the same period last year.

OPG's net income for the second quarter of 2003 was below that of the same period last year primarily as a result of lower electricity generation and sales, partially offset by higher energy prices. In addition, during the second quarter of 2002, OPG recorded a gain on the sale of hydroelectric stations on the Mississagi River.

Net income for the six months ended June 30, 2003 compared to last year was favourably impacted by open market energy prices, partially offset by higher fuel costs and lower electricity generation and sales. Also, OPG recorded provisions in the first quarter of 2002 for transitional price relief to certain power customers upon market opening and restructuring charges, which significantly reduced earnings last year.

OPG has experienced lower sales in 2003 compared to last year as a result of a decrease in hydroelectric production due to abnormally low water levels and lower nuclear production due to unplanned outages at the Pickering B nuclear station. Fossil production was increased to partially offset the impact of lower hydroelectric and nuclear generation.

During the second quarter, the Canadian Nuclear Safety Commission (CNSC) approved an increase in the level of output from the Darlington nuclear station from 98 per cent to 100 per cent, restoring the station's operational capacity by approximately 70 MW. In addition, OPG was granted a five year licence for the Pickering B nuclear station and a two year licence for the Pickering A station. In May 2003, OPG received approval from the CNSC to remove Unit 4 at the Pickering A nuclear station from its guaranteed shutdown state. This has allowed OPG to commence the testing and commissioning of the first unit at low power levels leading up to expected production of electricity in August. Further testing at high power will then commence, progressing to an in-service of the first unit during the summer of 2003.

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 six months ended June 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 is governed by the *Business Corporations Act* (Ontario) and is wholly-owned by the Province of Ontario.

As at June 30, 2003, OPG's electricity generating portfolio consisted of three nuclear stations, six fossil-fuelled generating stations, 36 hydroelectric generating stations and an EcoLogo[M] - certified green power portfolio including 29 small hydro and three wind generating stations. Two other nuclear generating stations are leased on a long-term basis to Bruce Power L.P. ("Bruce Power"). OPG's Pickering A nuclear generating station has been laid up since 1997. OPG is in the final phases of commissioning for the return to service of the first unit of this four-unit station.

HIGHLIGHTS

	Three Months Ended June 30		Six Months Ended June 30	
	2003	**2002**	**2003**	**2002**
(millions of dollars)				
Revenues	**1,246**	1,270	**2,726**	2,820
Net income (loss)	**12**	63	**88**	(154)
Cash flow provided by (used in) operating activities	**(508)**	(39)	**568**	88
Physical electricity sales volume (TWh)				
Generation segment	**26.0**	30.0	**55.1**	66.3
Energy Marketing segment	**1.4**	0.4	**2.1**	0.4
Total	**27.4**	30.4	**57.2**	66.7
Total energy available (TWh)				
Total production	**26.0**	28.0	**55.1**	58.8
Purchased power – Generation segment (1)	**-**	1.7	**-**	7.4
– Energy Marketing segment	**1.4**	0.4	**2.1**	0.4
Other	**-**	0.3	**-**	0.1
Total	**27.4**	30.4	**57.2**	66.7

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

Net income for the second quarter ended June 30, 2003 was $12 million compared to net income of $63 million for the same period in 2002, a decrease of $51 million. For the six months ended June 30, 2003, net income was $88 million compared with a loss of $154 million last year, an increase of $242 million. Significant factors impacting earnings in 2003 compared to 2002 included the following:

(millions of dollars – after tax)	**Three Months**	**Six Months**
Net income (loss) for the three and six month periods ending June 30, 2002	63	(154)
Higher energy prices	73	203
Higher prices for fossil fuel and change in generation mix	(39)	(93)
Lower volume and other changes in gross margin	(43)	(81)
Lower Pickering A return to service expenses	13	15
Increased OM&A expenses due to higher nuclear outage and project costs	(16)	(37)
Loss on Transition Rate Option contracts for industrial customers recorded in the first quarter of 2002	-	137
Restructuring charges recorded in the first quarter of 2002	-	133
Decrease in other income	(50)	(54)
Other net changes	11	19
Increase (decrease) in net income	(51)	242
Net income for the three and six month periods ending June 30, 2003	12	88

Cash flow used in operating activities in the second quarter of 2003 was $508 million compared to $39 million used in operating activities in the second quarter of 2002. The decrease in cash flow compared to last year was primarily due to payment of the Market Power Mitigation Agreement rebate of $759 million in May 2003 and an increase in contributions to the nuclear fixed asset removal and nuclear waste management funds, partially offset by other changes in working capital requirements.

Cash flow provided by operating activities for the six month period ended June 30, 2003 was $568 million compared to $88 million for the six month period ended June 30, 2002. The increase in cash flow was mainly due to higher energy prices, which resulted in an increase in the amount of the Market Power Mitigation Agreement rebate which had not yet been remitted as at June 30, 2003, and the receipt of proceeds from the repayment of the $225 million receivable from Bruce Power.

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.

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 wholesale and retail 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 Independent Electricity Market Operator ("IMO") exceeds 3.8¢/kWh and will be paid quarterly by the IMO.

OPG will continue 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 totalling approximately $807 million will be remitted for the three-month period ended April 30, 2003. OPG will pay this amount to the IMO by August 12, 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.

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 which 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

	Three Months Ended June 30		Six Months Ended June 30	
	2003	**2002**	**2003**	**2002**
(millions of dollars)				
Revenue	**1,144**	1,186	**2,526**	2,656
Fuel	**398**	336	**882**	735
Power purchased	**-**	71	**-**	290
Gross margin	**746**	779	**1,644**	1,631
Operations, maintenance and administration				
Expenses excluding Pickering A Return to Service	**530**	503	**1,051**	983
Pickering A Return to Service	**79**	101	**170**	195
Depreciation and amortization	**112**	113	**222**	225
Revalorization	**45**	51	**97**	97
Property and capital taxes	**24**	25	**49**	53
Operating income (loss)	**(44)**	(14)	**55**	78

Gross Margin

Gross margin from electricity sales in the Generation segment was $746 million for the second quarter of 2003 compared to $779 million for the same period in 2002, a decrease of $33 million. The decrease in gross margin was mainly due to lower electricity generation and a change in generation mix related to higher production from fossil stations and lower production from nuclear and hydroelectric stations, partially offset by higher energy prices.

Gross margin from electricity sales in the Generation segment was $1,644 million for the six months ended June 30, 2003 compared to $1,631 million for the same period in 2002, an increase of $13 million. The increase in gross margin was mainly due to higher electricity prices, largely offset by higher costs for coal, oil and natural gas fuel for fossil stations, and lower generation.

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 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 three and the six month periods ended June 30, 2003 compared to the same periods in 2002 was not significant.

Revenue

	Three Months Ended June 30		Six Months Ended June 30	
	2003	**2002**	**2003**	**2002**
(millions of dollars)				
Spot market sales, net of market power mitigation agreement rebate and financial transactions	**1,120**	668	**2,484**	668
Electricity sales (prior to market opening)	**-**	494	**-**	1,939
Other	**24**	24	**42**	49
Total generation revenue	**1,144**	1,186	**2,526**	2,656

Generation revenue was $1,144 million for the three month period ended June 30, 2003 compared to $1,186 million for the same period last year, a decrease of $42 million. The decrease was primarily due to a reduction in electricity sales volumes resulting from lower generation and termination upon market opening of the agreement to purchase and resell electricity produced by the Bruce nuclear generating stations from Bruce Power, largely offset by higher electricity prices.

For the six month period ended June 30, 2003, generation revenue was $2,526 million compared to $2,656 million for the same period in 2002, a decrease of $130 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 electricity produced by the Bruce nuclear generating stations from Bruce Power, lower generation, and the elimination, subsequent to market opening, of OPG's obligation to serve Ontario market demand. The impact of these reductions on revenue was partially offset by higher electricity prices.

Electricity Prices

Spot market prices in Ontario were impacted by colder weather during the six months ended June 30, 2003 compared to the same period last year. There were 2,687 Heating Degree Days[1] during the six months ended June 30, 2003 compared to 2,252 Heating Degree Days for the same period in 2002. The ten-year weather normal average for the six month period is 2,422 Heating Degree Days. While the colder weather resulted in higher Ontario spot market prices, 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 first six months of 2003, after taking into account the Market Power Mitigation Agreement rebate, was 4.6¢/kWh compared to the fixed revenue rate of 4.0¢/kWh prior to market opening on May 1, 2002 and 3.5¢/kWh during May and June of 2002. OPG's average spot market sales price for the second quarter of 2003 was 4.3¢/kWh after taking into account the Market Power Mitigation Agreement rebate.

[1] *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 required 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, approved 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 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 does not affect the rebate provided to customers under the Business Protection Plan.

Since the average hourly spot price during the six months ended June 30, 2003 has exceeded the 3.8¢/kWh revenue cap, OPG recorded $1,074 million as a Market Power Mitigation Agreement rebate for that period. The rebate is calculated in accordance with the Market Power Mitigation Agreement, after taking into account the amount of energy sales subject to the rebate mechanism for only those generating stations that OPG continues to control. At June 30, 2003, the Market Power Mitigation Agreement rebate payable was $887 million, after taking into account payments to the IMO of $335 million in December 2002 and $759 million in May 2003.

Volume

Electricity sales volumes for the second quarter of 2003 were 26.0 TWh compared to 30.0 TWh for the second quarter of 2002. For the six month period ended June 30, 2003, electricity sales were 55.1 TWh compared to 66.3 TWh for the same period last year. The decrease in volume was due primarily 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. For the three month and the six month periods ended June 30, 2002, OPG purchased and resold electricity from Bruce Power in the amount of 1.7 TWh and 6.8 TWh respectively. 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 quick melt, 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. Fossil production was increased to partially offset the impact of lower hydroelectric and nuclear generation.

	Three Months Ended June 30		Six Months Ended June 30	
	2003	**2002**	**2003**	**2002**
Total Energy Available for the Generation Segment (TWh)				
Production				
Nuclear:	**8.9**	10.5	**19.0**	21.3
Fossil	**9.2**	7.4	**21.0**	18.1
Hydroelectric	**7.9**	10.1	**15.1**	19.4
Total production	**26.0**	28.0	**55.1**	58.8
Power purchased	**-**	1.7	**-**	7.4
Other	**-**	0.3	**-**	0.1
Total Energy Available for the Generation Segment	**26.0**	30.0	**55.1**	66.3

Fuel and Power Purchases

Fuel expense for the second quarter of 2003 was $398 million compared to $336 million for the same period in 2002, an increase of $62 million. Fuel expense for the six month period ended June 30, 2003 was $882 million compared to $735 million for the same period last year, an increase of $147 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 three and six month periods ended June 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. During the three month period ended June 30, 2002, power purchased was $71 million based on purchases of 1.7 TWh. For the six month period ended June 30, 2002, power purchased was $290 million based on purchases of 7.4 TWh. The power purchased during 2002 was 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 $530 million for the three months ended June 30, 2003 compared to $503 million for the same period in 2002, an increase of $27 million. An increase in expenses in 2003 of $48 million related to increases in the scope and extent of scheduled maintenance work and improvements for nuclear stations, was partially offset by other reductions in expenses of $21 million, which included savings related to restructuring.

Operations, maintenance and administration expenses, excluding the Pickering A return to service initiative, were $1,051 million for the six month period ended June 30, 2003 compared to $983 million for the same period in 2002, an increase of $68 million. Increases in the scope and extent of scheduled maintenance work and improvements for nuclear stations in 2003 contributed to an increase in expenses of $99 million compared to last year. The impact of the higher maintenance costs was partially offset by other reductions in expenses of $31 million, including savings related to restructuring.

Pickering A Return To Service

Expenses related to the Pickering A return to service initiative were $79 million for the second quarter of 2003 compared to $101 million for the same period in 2002, a decrease of $22 million. For the six months ended June 30, 2003, expenses for the Pickering A return to service were $170 million compared to $195 million for the same period in 2002, a decrease of $25 million. The decrease was primarily due to a reduction in expenditures on the project as work is nearing completion on the return to service of the first unit.

Revalorization

Revalorization arises because liabilities for fixed asset removal and nuclear waste management are reported on a net present value basis. The revalorization charge is the adjustment that results from restating the liabilities to reflect the effect of inflation on the cost estimates and the time value of money effect on the future liabilities. Revalorization is reported net of the interest earned on the receivable from the Ontario Electricity Financial Corporation ("OEFC") and earnings on the nuclear fixed asset removal and nuclear waste management funds. Revalorization expense for the second quarter 2003 was $45 million compared with $51 million for the second quarter of 2002, a decrease of $6 million. The revalorization expense was $97 million for the six month periods ended June 30, 2003 and 2002.

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 three and six month periods ended June 30, 2002 reflect only the activities of May and June 2002.

	Three Months Ended June 30		**Six Months Ended June 30**	
	2003	**2002**	**2003**	**2002**
(millions of dollars)				
Revenue, net of power purchases	**21**	1	**42**	1
Operations, maintenance and administration	**2**	2	**4**	2
Operating income (loss)	**19**	(1)	**38**	(1)

Revenue

Revenue for the three and six month periods ended June 30, 2003 were $21 million and $42 million, respectively, compared to $1 million for the same periods last year. The increase during the second quarter and six month period ended June 30, 2003 reflected higher activity since the market for electricity opened 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 six month periods ended June 30, 2003 would have been $54 million and $91 million higher respectively, with no impact on net income.

Non-Energy and Other

	Three Months Ended June 30		Six Months Ended June 30	
	2003	**2002**	**2003**	**2002**
(millions of dollars)				
Revenue	**81**	83	**158**	163
Operations, maintenance and administration	**14**	14	**24**	32
Depreciation and amortization	**30**	29	**57**	56
Property and capital taxes	**3**	3	**6**	6
Loss on transition rate option contracts	**-**	-	**-**	210
Operating income (loss) before restructuring	**34**	37	**71**	(141)
Restructuring	**-**	-	**-**	210
Operating income (loss)	**34**	37	**71**	(351)
Other income	**41**	99	**41**	106
Net interest expense	**27**	39	**58**	78
Income (loss) before income taxes	**48**	97	**54**	(323)

Revenue

Non-energy revenue primarily consists of lease and other revenue derived under the lease agreement with Bruce Power. Under the agreement, the Company leased its Bruce A and Bruce B nuclear generating stations until 2018, with options to renew for up to 25 years. Non-energy revenue for the second quarter of 2003 was $81 million compared to $83 million for the same period in 2002. Non-energy revenue for the six months ended June 30, 2003 was $158 million compared to $163 million for the same period last year.

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 six month periods ended June 30, 2003, $19 million and $42 million respectively was charged against the provision and included in generation revenue. Since market opening in May 2002, $109 million has been charged against the provision and included in revenue.

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 June 30, 2003, OPG had approved severance packages for approximately 1,400 employees. Restructuring charges of $210 million were recorded during the six months ended June 30, 2002. There were no restructuring charges recorded during the first six months of 2003.

Other Income

Other income was $41 million for the three and the six month periods ended June 30, 2003 compared to $99 million and $106 million, respectively, for the same periods last year. During the second quarter of 2003, OPG sold certain long-term investments and realized a gain of $41 million. In May 2002, OPG completed the sale of four hydroelectric generating stations located on the Mississagi River and recorded a gain of $99 million. During the first quarter of 2002 OPG recorded gains of $7 million related to the sale of OPG's investments in New Horizon System Solutions Inc. and Kinectrics Inc.

Income Tax

For second quarter of 2003, the effective income tax rate was 50.0 per cent compared to an effective income tax rate of 23.2 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. Also, the effective income tax rate in the second quarter of 2002 was reduced by a non-taxable gain related to the sale of the Mississagi River generating stations.

For the six months ended in June 30, 2003, the effective income tax rate was 40.4 per cent compared to an effective income tax "recoverable" rate of 37.4 per cent in 2002. The increase in the effective income tax rate was primarily due to the impact of LCT, which increased the income tax payable in 2003, but reduced the amount of the income tax recoverable in 2002. The effective income tax rate in 2002 was also impacted by the non-taxable gain related to the sale of the Mississagi River generating stations, which increased the income tax recoverable rate in 2002.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow used in operating activities in the second quarter of 2003 was $508 million compared to $39 million used in operating activities in the second quarter of 2002, a decrease in cash of $469 million. The decrease in cash flow compared to last year was primarily due to payment of the Market Power Mitigation Agreement rebate of $759 million in May 2003 and an increase in contributions to the nuclear fixed asset removal and nuclear waste management funds, partially offset by other changes in working capital requirements.

Cash flow provided from operating activities for the six months ended June 30, 2003 was $568 million compared to $88 million for the six months ended June 30, 2002, an increase of $480 million. Higher energy prices, an increase in the Market Power Mitigation Agreement rebate payable of $315 million, and proceeds from the repayment of the $225 million receivable from Bruce Power contributed to a significant increase in cash flow. The Market Power Mitigation Agreement rebate payable increased from $572 million at December 31, 2002 to $887 million at June 30, 2003. OPG paid a rebate to the IMO of $759 million (excluding GST of $77 million) in May 2003. OPG will pay a further rebate to the IMO of approximately $807 million in August 2003. The increased cash flow was partially offset by increased contributions to the pension fund and the nuclear fixed asset removal and nuclear waste management funds.

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. 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.

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 second quarter of 2003 were $162 million compared with $210 million during the second quarter of 2002. Capital expenditures during the six months ended June 30, 2003 were $320 million compared with $366 million during the second quarter of 2002. The decrease was primarily due to the completion of certain major projects.

OPG made a contribution of approximately $27 million to the pension plan during the second quarter of 2003 and $80 million during the six months ended June 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 $293 million during the six months ended June 30, 2003 compared to $160 million during the same period last year, due to the timing of contributions and income earned on investments. OPG is required to make contributions in 2003 of approximately $454 million to the nuclear fixed asset removal and nuclear waste management funds under the Ontario Nuclear Funds Agreement.

On July 24, 2003, OPG and the Province of Ontario (the "Province") completed the arrangements pursuant to the Ontario Nuclear Funds Agreement, which requires the establishment of segregated custodial accounts and investment management agreements. Under the Ontario Nuclear Funds Agreement, the majority of OPG's existing nuclear fixed asset removal and nuclear waste management funds were transferred to these segregated custodial funds. In addition, the Ontario Electricity Financial Corporation contributed $1.2 billion in respect of amounts receivable from the OEFC.

In addition, effective as at July 31, 2003, the Province issued a guarantee on behalf of OPG, to the Canadian Nuclear and Safety Commission in a maximum amount of $1.51 billion. The guarantee, taken together with the establishment of The Ontario NFWA Trust ("Nuclear Fuel Trust Fund") and the segregated custodial funds, were in satisfaction of OPG's nuclear licencing requirements. OPG pays the Province a guarantee fee of 0.5% of the amount guaranteed by the Province on an annual basis.

The Company paid dividends to the Province of $17 million during the six months ended June 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 a 35 per cent pay-out based on 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 June 30, 2003, OPG had $105 million outstanding under the CP program.

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 repaid. 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 Retail Settlement Code, Ontario. The amount of collateral required by LDCs varies depending on the size of OPG's customers embedded within a LDC franchise area.

PICKERING A RETURN TO SERVICE

OPG continues to progress with the safety and environmental upgrades and other refurbishment work that is required prior to the return to service of the Pickering A nuclear generating station units. The environmental upgrades and refurbishment work on the first of the four units, as well as common operating systems for all four units, is largely complete.

In April 2003, OPG applied to the Canadian Nuclear Safety Commission and subsequently received approval to remove the first unit from its guaranteed shut-down state. This has allowed OPG to commence the testing and commissioning of the first unit at low power levels. Through this testing and commissioning, OPG has identified the requirement for some further adjustments and modifications to the equipment.

Testing on the first unit is continuing at low power, leading up to the first synchronization of the generator to the grid and production of electricity at low power levels. Further testing at higher power will then commence, progressing to an in-service of the first unit during the summer of 2003. There remain risks that further work and modifications may be identified through the testing and commissioning process as power levels increase.

Initial work, focused on engineering, planning and assessing, for the return to service of the second unit is underway. 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 the first unit to service. The detailed schedule and cost estimate is expected to be complete by early 2004. It is too early in this process to provide an updated estimate of the cost of subsequent units.

On May 30, 2003, Ontario's Minister of Energy announced that a three-member team 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 team is to provide an interim report to the Minister in the fall of 2003 and a full report by December 31, 2003.

Cumulative life-to-date expenditures on the return to service initiative for the first unit and the common operating systems for all four units totalled $1,246 million through the end of June 2003. The total cumulative expenditures on all four units to the end of June 2003 were $1,438 million. The cost to return the first unit to service, including the cost of the common operating systems, is estimated at approximately $1,265 million. The increase in estimated costs from the previous estimate of $1,200 million reflects the requirement to extend the commissioning period.

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. OPG's approved VaR limit is $5 million. VaR utilization ranged between $0.4 million to $1.6 million during the three and six months ended June 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]	82%	83%	78%
Estimated fuel requirements hedged [2]	94%	79%	75%

[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 six months ended June 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 June 30, 2003.

(millions of dollars)			Potential Exposure for 10 Largest Counterparties	
Credit Rating [1]	Number of Counterparties	Potential Exposure [2]	Number of Counterparties	Counterparty Exposure
AAA to AA-	9	40	1	15
A+ to A-	40	214	4	156
BBB+ to BBB-	68	136	3	42
BB+ to BB-	26	42	1	15
B+ to B-	18	15	-	-
	161	447	9	228
IMO	1	410	1	410
Total	162	857	10	638

[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

On April 30, 2003, the Province of Ontario announced, in the Throne Speech that; "Starting immediately, your government will phase out coal-fired generating stations no later than 2015". The Company is assessing the potential implications of this announcement on its operations, and will continue to evaluate the impact as further information becomes available. Other political parties have suggested earlier phase-outs.

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)

	Three Months Ended June 30		Six Months Ended June 30	
	2003	**2002**	**2003**	**2002**
(millions of dollars except where noted)				
Revenues	**1,246**	1,270	**2,726**	2,820
Fuel	**398**	336	**882**	735
Power purchased	**-**	71	**-**	290
Gross Margin	**848**	863	**1,844**	1,795
Operating expenses				
Operations, maintenance and administration	**625**	620	**1,249**	1,212
Depreciation and amortization *(note 9)*	**142**	142	**279**	281
Revalorization	**45**	51	**97**	97
Property and capital taxes	**27**	28	**55**	59
Loss on transition rate option contracts *(note 10)*	**-**	-	**-**	210
	839	841	**1,680**	1,859
Operating income (loss) before restructuring	**9**	22	**164**	(64)
Restructuring *(note 11)*	**-**	-	**-**	210
Operating income (loss)	**9**	22	**164**	(274)
Other income *(note 13)*	**41**	99	**41**	106
Net interest expense	**27**	39	**58**	78
	(14)	(60)	**17**	(28)
Income (loss) before income taxes	**23**	82	**147**	(246)
Income taxes (recoveries)				
Current	**(17)**	23	**60**	(45)
Future	**28**	(4)	**(1)**	(47)
	11	19	**59**	(92)
Net income (loss)	**12**	63	**88**	(154)
Basic and diluted earnings (loss) per common share *(dollars)*	**0.05**	0.25	**0.34**	(0.60)
Common shares outstanding *(millions)*	**256.3**	256.3	**256.3**	256.3

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (UNAUDITED)

Six Months Ended June 30	**2003**	**2002**
(millions of dollars)		
Retained earnings, beginning of period	**257**	344
Net income (loss)	**88**	(154)
Dividends	**(17)**	(134)
Retained earnings, end of period	**328**	56

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Three Months Ended June 30		Six Months Ended June 30	
	2003	**2002**	**2003**	**2002**
(millions of dollars)				
Operating activities				
Net income (loss)	**12**	63	**88**	(154)
Adjust for non-cash items:				
Depreciation and amortization *(note 9)*	**142**	142	**279**	281
Revalorization	**45**	51	**97**	97
Pension	**(4)**	(18)	**(3)**	4
Other post employment benefits	**35**	51	**68**	75
Future income taxes	**28**	(4)	**(1)**	(47)
Provision for restructuring *(note 11)*	**-**	-	**-**	210
Transition rate option contracts *(note 10)*	**(19)**	(18)	**(42)**	192
Gain on sale of investments	**(41)**	-	**(41)**	(7)
Gain on sale of decontrol fixed assets	**-**	(99)	**-**	(99)
Mark to market on energy contracts	**(8)**	(2)	**(6)**	(2)
Earnings on nuclear waste management funds	**18**	19	**34**	38
Other	**1**	17	**11**	28
	209	202	**484**	616
Contributions to fixed asset removal and nuclear waste management fund	**(277)**	(109)	**(293)**	(160)
Expenditures on nuclear waste management	**(16)**	(21)	**(31)**	(52)
Market power mitigation agreement rebate payment	**(759)**	-	**(759)**	-
Contributions to pension fund	**(27)**	-	**(80)**	-
Expenditures on other post employment benefits	**(13)**	(15)	**(23)**	(23)
Expenditures on restructuring *(note 11)*	**(15)**	(64)	**(44)**	(64)
Net changes to other long-term assets and liabilities	**(31)**	(83)	**(41)**	(81)
Changes in non-cash working capital balances *(note 14)*	**421**	51	**1,355**	(148)
Cash flow provided by (used in) operating activities	**(508)**	(39)	**568**	88
Investing activities				
Net proceeds from short-term investments	**-**	-	**-**	39
Proceeds on sale of decontrol fixed assets	**-**	342	**1**	342
Cash proceeds from sale of investments	**41**	-	**41**	14
Purchases of fixed assets	**(162)**	(210)	**(320)**	(366)
Cash flow provided by (used in) investing activities	**(121)**	132	**(278)**	29
Financing activities				
Issuance of long-term debt *(note 5)*	**24**	-	**52**	-
Dividends paid	**-**	-	**(17)**	(134)
Short-term notes issued	**185**	-	**390**	200
Short-term notes repaid	**(270)**	(200)	**(467)**	(200)
Cash flow used in financing activities	**(61)**	(200)	**(42)**	(134)
Net increase (decrease) in cash and cash equivalents	**(690)**	(107)	**248**	(17)
Cash and cash equivalents, beginning of period	**1,562**	90	**624**	-
Cash and cash equivalents, end of period	**872**	(17)	**872**	(17)

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(millions of dollars)	**June 30 2003**	**December 31 2002**
Assets		
Current assets		
Cash and cash equivalents	**872**	624
Accounts receivable	**598**	736
Note receivable *(note 7)*	**-**	225
Income taxes recoverable	**16**	80
Fuel inventory	**471**	514
Materials and supplies	**74**	80
	2,031	2,259
Fixed assets		
Property, plant and equipment	**15,284**	15,014
Less: accumulated depreciation	**2,359**	2,068
	12,925	12,946
Other long-term assets		
Deferred pension asset	**388**	305
Nuclear fixed asset removal and nuclear waste management funds *(note 6)*	**1,892**	1,599
Materials and supplies	**208**	193
Long-term accounts receivable and other assets	**65**	59
	2,553	2,156
	17,509	17,361

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(millions of dollars)	June 30 2003	December 31 2002
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(note 10)*	**988**	1,235
Market Power Mitigation Agreement rebate payable *(note 3)*	**887**	572
Short-term notes payable *(note 4)*	**105**	182
Deferred revenue due within one year	**12**	12
Long-term debt due within one year *(note 5)*	**4**	5
	1,996	2,006
Long-term debt *(note 5)*	**3,405**	3,352
Other long-term liabilities		
Fixed asset removal and nuclear waste management *(note 6)*	**4,963**	4,915
Other post employment benefits	**1,003**	958
Long-term accounts payable and accrued charges *(note 10)*	**269**	321
Deferred revenue	**173**	179
Future income taxes	**246**	247
	6,654	6,620
Shareholder's equity		
Common shares	**5,126**	5,126
Retained earnings	**328**	257
	5,454	5,383
	17,509	17,361

Commitments and Contingencies *(note 15)*

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE THREE AND SIX MONTHS ENDED JUNE 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

Depreciation and Amortization

Depreciation rates for the various classes of assets are based on their estimated service lives. Any asset removal costs that have not been specifically provided for in current or previous periods are also charged to depreciation expense. Depreciation and amortization includes expenses relating to low and intermediate level waste generated each year. Depreciation and amortization also includes the amortization of changes in estimates of the liability for nuclear waste management.

Repairs and maintenance costs are expensed when incurred.

Fixed assets are depreciated on a straight-line basis except for computers, and transport and work equipment, which are depreciated on a declining balance basis.

Revalorization

Revalorization arises because liabilities for fixed asset removal and nuclear waste management are reported on a net present value basis. The revalorization charge is the adjustment that results from restating the liabilities to reflect the effect of inflation on the cost estimates and the time value of money effect on the future liabilities. Revalorization is reported net of the interest earned on the receivable from the Ontario Electricity Financial Corporation ("OEFC") and the earnings on the nuclear fixed asset removal and nuclear waste management funds.

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 mechanism. 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. 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.

Since the average hourly spot price during the second quarter and six month periods ended June 30, 2003 has exceeded the 3.8¢/kWh revenue cap, OPG provided $221 million and $1,074 million, respectively, as a Market Power Mitigation Agreement rebate (second quarter and six month period ended June 30, 2002 – nil). The rebate is calculated in accordance with the Market Power Mitigation Agreement, after taking into account the amount of energy sales subject to the rebate mechanism for only those generating stations that OPG continues to control.

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

For the six months ended June 30	**2003**
(millions of dollars)	
Liability, as at December 31, 2002	**572**
Increase to provision during the period	**1,074**
Payments	**(759)**
Liability, as at June 30, 2003	**887**

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)	**June 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: payable within one year		
Capital lease obligations	**4**	5
Long-term debt	**3,405**	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 June 30, 2003 was $1 million (three months ended June 30, 2002 - $1 million), of which nil (three months ended June 30, 2002 - nil) relates to interest paid on long-term debt. Interest paid during the six months ended June 30, 2003 was $98 million (six months ended June 30, 2002 - $96 million), of which $96 million (six months ended June 30, 2002 - $95 million) relates to interest paid on long-term debt.

6. Fixed Asset Removal and Nuclear Waste Management

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

(millions of dollars)	**June 30 2003**	**December 31 2002**
Liability for nuclear waste management	**5,081**	5,020
Liability for nuclear fixed asset removal	**2,767**	2,702
	7,848	7,722
Liability for non-nuclear fixed asset removal	**133**	131
	7,981	7,853
Less: Receivable from the OEFC	**3,018**	2,938
Fixed asset removal and nuclear waste management	**4,963**	4,915

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

For the six months ended June 30	**2003**
(millions of dollars)	
Liability, as at December 31, 2002	**4,915**
Increase in the liability due to revalorization	**131**
Provision	**11**
Waste management expenditures	**(31)**
Balance sheet reclassification of expenditures	**(41)**
Amortization of cost estimate changes	**(22)**
Liability, as at June 30, 2003	**4,963**

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

(millions of dollars)	**June 30 2003**	**December 31 2002**
Nuclear fixed asset removal and nuclear waste management funds	**1,366**	1,098
Nuclear Used Fuel Trust Fund	**526**	501
	1,892	1,599

On July 24, 2003, OPG and the Province of Ontario (the "Province") completed the arrangements pursuant to the Ontario Nuclear Funds Agreement, which requires the establishment of segregated custodial accounts and investment management agreements. Under the Ontario Nuclear Funds Agreement, the majority of OPG's existing nuclear fixed asset removal and nuclear waste management funds were transferred to these segregated custodial funds. In addition, the Ontario Electricity Financial Corporation contributed $1.2 billion in respect of amounts receivable from the OEFC.

After given effect to the foregoing, the following funds were held in custodial accounts as at July 24, 2003:

(millions of dollars)	Used Fuel Fund	Decommissioning Fund
The Ontario NFWA Trust	534	
Amounts transferred from fixed asset removal and nuclear waste management funds	801	534
Amounts received from the OEFC		1,200
Receivable from the OEFC		1,851
Total	1,335	3,585

In addition, effective as at July 31, 2003, the Province issued a guarantee on behalf of OPG, to the Canadian Nuclear and Safety Commission in a maximum amount of $1.51 billion. The guarantee, taken together with the establishment of The Ontario NFWA Trust ("Nuclear Fuel Trust Fund") and the segregated custodial funds, were in satisfaction of OPG's nuclear licencing requirements. OPG pays the Province a guarantee fee of 0.5% of the amount guaranteed by the Province on an annual basis.

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 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 repaid, 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

OPG continues to evaluate options for decontrol of stations and is committed to meet its obligations under the Market Power Mitigation Agreement. The process for meeting decontrol of price-setting generation has been impacted by current market conditions in the North American energy sector. The amounts that OPG will ultimately realize with respect to these potential transactions could differ materially from the carrying values recorded in the consolidated financial statements.

Other Initiatives

The Company is in the process of selling its Inspection Services Division that performs required technical inspections of key components of its nuclear and other production facilities, such as boilers, fuel channels and steam generators. If successful, this process is expected to be completed sometime in the fourth quarter of 2003.

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.

Since November 2002, 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 six months ended June 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)	**June 30, 2003**			**December 31, 2002**		
Gain/(loss)	**Notional quantity**	**Terms**	**Fair Value**	**Notional quantity**	**Terms**	**Fair Value**
Electricity derivative instruments	**30 TWh**	**1-4 yrs**	**(121)**	37.9 TWh	1-4 yrs	(144)
Foreign exchange derivative instruments	**$415 US**	**1-7 months**	**(47)**	$179 US	Apr/03	4
Option to purchase emission reduction credits	**6,000,000 tonnes**	**2003-2004**	**1**	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)	**June 30, 2003**		**December 31, 2002**	
	Notional quantity	**Fair Value**	**Notional quantity**	**Fair Value**
Commodity derivative instruments				
Assets	**9.2 TWh**	**14**	**7.7 TWh**	**10**
Liabilities	**1.3 TWh**	**(6)**	**2.9 TWh**	**(14)**
		8		**(4)**
Ontario market liquidity reserve		**(12)**		**(7)**
Total		**(4)**		**(11)**

9. DEPRECIATION AND AMORTIZATION

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

For the three months ended June 30	**2003**	**2002**
(millions of dollars)		
Depreciation	**153**	146
Nuclear waste management costs	**1**	2
Change in estimate of the nuclear waste management liability	**(12)**	(6)
	142	142

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

For the six months ended June 30	**2003**	**2002**
(millions of dollars)		
Depreciation	**301**	289
Nuclear waste management costs	**2**	3
Change in estimate of the nuclear waste management liability	**(24)**	(11)
	279	281

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 reasonably 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 June 30, 2003, the provision has been reduced by $19 million (2002 – $18). For the six month period ended June 30, 2003, the provision was reduced by $42 million (2002 – $18). At June 30, 2003, the current portion of the provision for loss on these contracts was $65 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 $36 million (December 31, 2002 - $62 million).

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 six months ended June 30, 2003 is as follows:

For the six months ended June 30	**2003**
(millions of dollars)	
Liability, as at December 31, 2002	**120**
Payments during the period	**(44)**
Liability, as at June 30, 2003	**76**

During the second quarter of 2002, there were no restructuring charges for severance. Severance payments during the second quarter of 2002 totalled $65 million. During the six months ended June 30, 2002, a restructuring charge for severance of $201 million was recorded and severance payments totalled $72 million.

12. Business Segments

Segment Income for the three months ended June 30, 2003	**Generation**	**Energy Marketing**	**Non-Energy and Other**	**Total**
(millions of dollars)				
Revenues	**1,144**	**21**	**81**	**1,246**
Fuel	**398**	**-**	**-**	**398**
Gross margin	**746**	**21**	**81**	**848**
Operations, maintenance and administration	**530**	**2**	**14**	**546**
Pickering A return to service	**79**	**-**	**-**	**79**
Depreciation and amortization	**112**	**-**	**30**	**142**
Revalorization	**45**	**-**	**-**	**45**
Property and capital taxes	**24**	**-**	**3**	**27**
Operating income (loss)	**(44)**	**19**	**34**	**9**
Other income	**-**	**-**	**41**	**41**
Net interest expense	**-**	**-**	**27**	**27**
Income (loss) before income taxes	**(44)**	**19**	**48**	**23**

Segment Income for the three months ended June 30, 2002	**Generation**	**Energy Marketing**	**Non-Energy and Other**	**Total**
(millions of dollars)				
Revenues	1,186	1	83	1,270
Fuel	336	-	-	336
Power purchased	71	-	-	71
Gross margin	779	1	83	863
Operations, maintenance and administration	503	2	14	519
Pickering A return to service	101	-	-	101
Depreciation and amortization	113	-	29	142
Revalorization	51	-	-	51
Property and capital taxes	25	-	3	28
Operating income (loss)	(14)	(1)	37	22
Other income	-	-	99	99
Net interest expense	-	-	39	39
Income (loss) before income taxes	(14)	(1)	97	82

Segment Income for the six months ended June 30, 2003	**Generation**	**Energy Marketing**	**Non-Energy and Other**	**Total**
(millions of dollars)				
Revenues	**2,526**	**42**	**158**	**2,726**
Fuel	**882**	**-**	**-**	**882**
Gross margin	**1,644**	**42**	**158**	**1,844**
Operations, maintenance and administration	**1,051**	**4**	**24**	**1,079**
Pickering A return to service	**170**	**-**	**-**	**170**
Depreciation and amortization	**222**	**-**	**57**	**279**
Revalorization	**97**	**-**	**-**	**97**
Property and capital taxes	**49**	**-**	**6**	**55**
Operating income	**55**	**38**	**71**	**164**
Other income	**-**	**-**	**41**	**41**
Net interest expense	**-**	**-**	**58**	**58**
Income before income taxes	**55**	**38**	**54**	**147**

Segment Income for the six months ended June 30, 2002	**Generation**	**Energy Marketing**	**Non-Energy and Other**	**Total**
(millions of dollars)				
Revenues	2,656	1	163	2,820
Fuel	735	-	-	735
Power purchased	290	-	-	290
Gross margin	1,631	1	163	1,795
Operations, maintenance and administration	983	2	32	1,017
Pickering A return to service	195	-	-	195
Depreciation and amortization	225	-	56	281
Revalorization	97	-	-	97
Property and capital taxes	53	-	6	59
Loss on transition rate option contracts	-	-	210	210
Operating income (loss) before restructuring	78	(1)	(141)	(64)
Restructuring	-	-	210	210
Operating income (loss)	78	(1)	(351)	(274)
Other income	-	-	106	106
Net interest expense	-	-	78	78
Income (loss) before income taxes	78	(1)	(323)	(246)

	Generation	**Energy Marketing**	**Non-Energy and Other**	**Total**
Selected Balance Sheet Information				
(millions of dollars)				
June 30, 2003				
Segment property, plant and equipment, net	**11,989**	-	**936**	**12,925**
December 31, 2002				
Segment property, plant and equipment, net	12,003	-	943	12,946
Selected Cash Flow Information				
(millions of dollars)				
Three months ended June 30, 2003				
Capital expenditures	**140**	**-**	**22**	**162**
Three months ended June 30, 2002				
Capital expenditures	171	-	39	210

	Generation	Energy Marketing	Non-Energy and Other	Total
Selected Cash Flow Information *(millions of dollars)*				
Six months ended June 30, 2003				
Capital expenditures	**281**	**-**	**39**	**320**
Six months ended June 30, 2002				
Capital expenditures	327	-	39	366

13. Other Income

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

	Three Months Ended June 30		Six Months Ended June 30	
	2003	**2002**	**2003**	**2002**
Sale of Mississagi River generating stations	**-**	**99**	**-**	99
Sale of investment in Kinectrics Inc.	**-**	-	**-**	3
Sale of investment in New Horizon Systems Solutions Inc.	**-**	-	**-**	4
Gain on sale of long-term investments	**41**	-	**41**	-
	41	**99**	**41**	106

14. Changes in Non-Cash Working Capital Balances

	Three Months Ended June 30		Six Months Ended June 30	
	2003	**2002**	**2003**	**2002**
(millions of dollars)				
Accounts receivable	**377**	570	**138**	588
Note receivable	**-**	-	**225**	-
Income taxes recoverable	**(16)**	10	**64**	(77)
Fuel inventory	**(68)**	(64)	**43**	(48)
Materials and supplies	**(1)**	(16)	**(1)**	(19)
Market power mitigation agreement rebate	**221**	-	**1,074**	-
Accounts payable and accrued charges	**(92)**	(449)	**(188)**	(592)
	421	51	**1,355**	(148)
Supplementary disclosure				
Income taxes paid	**5**	17	**8**	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.