ONTARIO POWER GENERATION

News
from Ontario Power Generation

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October 28, 2002

ONTARIO POWER GENERATION REPORTS 2002 THIRD QUARTER EARNINGS

[Toronto]: Ontario Power Generation Inc. (OPG) today reported its financial and operating results for the third quarter and first nine months ended September 30, 2002. Earnings for the three months ended September 30, 2002 were $215 million or $0.84 per share, as compared with third quarter earnings in 2001 of $81 million or $0.32 per share. For the nine months ended September 30, 2002, earnings were $61 million or $0.24 per share compared to earnings of $200 million or $0.78 per share for the same period last year.

"OPG's third quarter earnings reflect open market prices for the summer period and the impact of warmer than normal weather, and a favourable generation mix related to higher nuclear and hydroelectric generation. OPG is mandated under its operating licence to rebate a significant portion of its revenues that were in excess of 3.8 cents per kWh, which will reduce the impact of higher market prices on consumers," said OPG President and CEO, Ron Osborne.

"Our nine month results are below those of the same period last year mainly due to restructuring charges, a provision on transition rate option contracts for industrial customers taken in the first quarter and increased expenditures related to Pickering A, partially offset by the impact of higher spot market prices and the gain on sale of the Mississagi River stations," said Osborne. OPG expects to begin commissioning the first unit at Pickering A nuclear generating station during the first quarter of 2003.

Peak demand in Ontario reached record levels during the third quarter with a new peak of 25,414 MW being set on August 13. The benefits of focussing on improved performance were demonstrated when our generating assets responded to Ontario's increased electricity needs by producing 4 per cent more electricity than in the third quarter of 2001. In particular, the performance of OPG's nuclear generating stations continues to improve, achieving a forced outage rate of 1.7 per cent for the third quarter of 2002 compared to 1.9 per cent for the same period last year. For the nine months ended September 30, 2002, the forced outage rate was 2.3 per cent compared to 3.0 per cent last year.

Ontario Power Generation is an Ontario based company, whose principal business is the generation and sale of electricity to customers 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.

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

THIRD QUARTER 2002 RESULTS

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, 2002. 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, 2001. OPG's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles and are presented in Canadian dollars.

BUSINESS SEGMENTS

Commencing May 1, 2002, upon the opening of the Ontario electricity market to competition, OPG now classifies its operations into two business segments: Generation and Energy Marketing. A separate category, Non-Energy and Other, includes revenue and certain costs which are not allocated to the two business segments.

Generation Segment

With the opening of the Ontario electricity market to competition on May 1, 2002, all of OPG's electricity generation is sold into the real-time energy spot market administered by the Independent Electricity Market Operator ("IMO"), in order to be dispatched. As such, the majority of OPG's revenue is derived from spot market sales for which OPG receives a variable price based on supply and demand dynamics. Revenue is also earned through offering available capacity as operating reserve and through the supply of other ancillary services including voltage control/reactive support, black start capability and automatic generation control. Prior to market opening, OPG sold electricity directly to wholesale electricity customers in Ontario, including local distribution companies and large industrial customers, and to customers in the interconnected markets of Quebec, Manitoba and the northeast and midwest regions of the United States.

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

Energy Marketing Segment

OPG sells into, and purchases from, interconnected markets of other provinces and the U.S. northeast and midwest. The Energy Marketing segment also includes trading, and the sale of risk management and other energy-related products and services to meet customers' needs for energy solutions. All contracts that are not designated as hedges are valued at market value with changes in fair value recorded in energy marketing revenue as energy marketing gains or losses.

Non-Energy and Other

OPG derives non-energy revenue under the terms of a lease arrangement with Bruce Power L.P. ("Bruce Power") related to the Bruce Nuclear Generating Stations. This includes lease revenue, interest income and revenue from engineering analysis and design, technical and ancillary services. Non-energy revenue also includes isotope sales to the medical industry.

Highlights

(millions of dollars unless otherwise stated)	Three Months Ended September 30 2002	Three Months Ended September 30 2001	Nine Months Ended September 30 2002	Nine Months Ended September 30 2001
Revenues	**1,648**	1,635	**4,486**	4,681
Net income	**215**	81	**61**	200
Earnings per common share ($ per common share)	**0.84**	0.32	**0.24**	0.78
Cash flow provided by (used in) operating activities	**446**	(24)	**534**	177
Total physical electricity sales volume (TWh)				
Generation segment	**28.9**	35.8	**95.2**	106.6
Energy Marketing segment	**0.6**	-	**1.0**	-
Total	**29.5**	35.8	**96.2**	106.6
Total energy available (TWh)				
Total production	**28.9**	27.8	**87.7**	93.6
Purchased power	**0.6**	7.9	**8.4**	13.7
Other *	**-**	0.1	**0.1**	(0.7)
Total	**29.5**	35.8	**96.2**	106.6

*Represents deposits and withdrawals of electricity with utilities in neighbouring jurisdictions under energy banking arrangements.

For the three months ended September 30, 2002, OPG had net income of $215 million compared with net income of $81 million for the same period in 2001, an increase of $134 million. For the nine months ended September 30, 2002, OPG had net income of $61 million compared with $200 million for the same period last year, a decrease of $139 million. Significant factors impacting earnings in 2002 compared to 2001 included the following:

Change in Earnings – 2002 compared to 2001 (millions of dollars – after tax)	Three Months	Nine Months
Net income for the period ended September 30, 2001	81	200
Higher energy prices	145	89
Other changes in gross margin due to a favourable generation mix and lower power purchases, partially offset by higher coal costs	65	69
Impact of decontrol – decrease in gross margin partially offset by OM&A and other savings	(10)	(42)
Higher activity levels and expenditures related to the return to service of the Pickering A nuclear generating station	(8)	(65)
Decrease in OM&A expenses due to lower pension and OPEB expenses, WSIB settlement, completion of nuclear recovery programs and lower nuclear outage costs	27	54
Gain on sale of Mississagi River stations	-	79
Restructuring charge for costs related to a reduction in workforce	(7)	(141)
Loss on Transition Rate Option contracts for industrial customers after market opening	-	(137)
One time impact of the reduction in income tax rates in 2001 and other changes in temporary and permanent differences	(44)	(23)
Other items, net	(34)	(22)
Increase (decrease) in earnings	134	(139)
Net Income for the period ended September 30, 2002	215	61

DISCUSSION OF SEGMENTED RESULTS

Generation Segment

(millions of dollars)	Three Months Ended September 30 2002	2001	Nine Months Ended September 30 2002	2001
Revenue	**1,504**	1,553	**4,160**	4,521
Fuel	**412**	393	**1,147**	1,099
Power purchased	**-**	374	**290**	649
Gross margin	**1,092**	786	**2,723**	2,773
Operation, maintenance and administration	**569**	579	**1,747**	1,818
Depreciation and amortization	**153**	179	**486**	566
Property and capital taxes	**26**	-	**79**	43
Operating income	**344**	28	**411**	346

Gross Margin

The gross margin from electricity sales in the Generation segment was $1,092 million for the third quarter of 2002 compared to $786 million for the same period in 2001, an increase of $306 million. The increase in margin was primarily due to higher electricity prices in the third quarter of 2002, a favourable generation mix related to higher production from OPG's nuclear and hydroelectric generating stations, and the impact on margin, in 2001, of high cost power purchases and other resources that were required to meet peak demand. Under the fixed price regime in 2001, OPG had an obligation to serve customer demand and was not always able to fully recover these higher costs. The impact of these factors on gross margin was partially offset by higher coal costs in 2002.

The gross margin for the nine months ended September 30, 2002 was $2,723 million compared to $2,773 million for the same period last year, a decrease of $50 million. The most significant factor contributing to the decrease in gross margin was the impact of the decontrol of the Bruce Nuclear Generating Stations. On May 11, 2001, OPG completed the agreement to lease its Bruce Nuclear Generating Stations to Bruce Power. Higher coal costs also contributed to a decrease in the margin in 2002 compared to last year. The impact of decontrol and higher coal costs were partially offset by higher electricity prices in 2002, a favourable generation mix related to higher production from OPG's nuclear and hydroelectric generating stations, and a decrease in high cost power purchases which were required in 2001 to meet market demand.

Revenue

(millions of dollars)	Three Months Ended September 30 2002	2001	Nine Months Ended September 30 2002	2001
Spot market sales net of market power mitigation agreement rebate	**1,540**	-	**2,178**	-
Electricity sales (prior to market opening)	**-**	1,527	**1,939**	4,444
Financial transactions (sales contracts)	**(55)**	-	**(25)**	-
Other	**19**	26	**68**	77
Total generation revenue	**1,504**	1,553	**4,160**	4,521

Generation revenue was $1,504 million for the three months ended September 30, 2002 compared to $1,553 million for the same period in 2001, a decrease of $49 million. For the nine months ended September 30, 2002, generation revenue was $4,160 million compared to $4,521 million for the same period last year, a decrease of $361 million. The decrease in generation revenue was primarily due to lower volumes resulting from the decontrol of the Bruce Nuclear Generating Stations and the elimination, subsequent to market opening, of OPG's obligation to serve Ontario market demand, partially offset by higher electricity prices.

Spot market prices in Ontario were impacted significantly by much warmer summer temperatures in 2002. There were 504 cooling degree days[1] through the end of September compared to 385 cooling degree days in 2001 and weather normal degree days of 266. While the unusually warm weather during 2002 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 a market power mitigation agreement rebate mechanism. OPG's average spot market sales price for the three months ended September 30, 2002, after taking into account the market power mitigation agreement rebate, was 5.2¢/kWh compared to an average revenue rate of 4.0¢/kWh during the same period last year. The 5.2¢/kWh average price in the third quarter includes an increase of 0.2¢/kWh as a result of prices lower than the revenue cap of 3.8¢/kWh in May and June 2002. Since market opening on May 1, 2002, the average spot market price net of the market power mitigation agreement rebate was 4.5¢/kWh compared to an average revenue rate of 4.0¢/kWh during the same period in 2001.

Market Power Mitigation Agreement Rebate

OPG is required under its generating licence to comply with prescribed market power mitigation measures, including a rebate mechanism, to address the potential for OPG to exercise market power in Ontario. Under the rebate mechanism, for the first four years after market opening, a significant majority of OPG's expected energy sales in Ontario are subject to an average annual revenue cap of 3.8¢/kWh. OPG is required to pay a rebate to the IMO, for ultimate distribution to customers, 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 generating 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 eliminate a portion of the market power mitigation agreement rebate obligation ("Decontrol Mitigation"). In order for a transaction to qualify for decontrol, OPG must meet the following three tests:

- The transaction must transfer control over timing, quantity, and bidding of output into the Ontario market to a third party.
- There must not be on-going arrangements which facilitate interdependent behaviour.
- The transferee may not control more than 25 per cent of Ontario capacity.

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 of its hydroelectric stations located on the Mississagi River to Great Lakes Hydro Income Fund. OPG has filed an application with the OEB seeking a reduction in the amount of energy subject to the rebate mechanism as a result of the decontrol of the Bruce Nuclear Generating Stations and is in the process of preparing an application related to the sale of the Mississagi River stations. The Company believes that it has met all of the requirements for the transfer of effective control and therefore should receive a reduction in energy sales subject to the market power mitigation agreement rebate. OEB approval of the applications would result in a reduction in volumes subject to the market power mitigation agreement rebate for the twelve-month settlement period ending April 30, 2003 from 101.8 TWh to 81.4 TWh.

[1] *Cooling Degree Days represent the aggregate of the excess of average daily temperatures over 18^{0}C.*

Since the average hourly spot price since May 1, 2002 has exceeded the 3.8¢/kWh revenue cap, OPG has recorded a market power mitigation agreement rebate liability at September 30, 2002 equal to the excess of the average hourly spot energy price over 3.8¢/kWh, multiplied by the amount of energy subject to the rebate mechanism. As at September 30, 2002, the Company had deferred 1.779¢/kWh on a volume of 31.7 TWh. The rebate liability was 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.

OPG expects to receive a decision from the OEB regarding the Decontrol Mitigation during the first quarter of 2003. If OPG's application is not approved, revenue in the period in which the determination is made would be decreased by the amount of the Decontrol Mitigation, which totalled approximately $110 million at September 30, 2002.

Volume

Electricity sales volumes for the third quarter ended September 30, 2002 were 28.9 TWh, compared to 35.8 TWh for the same period last year. For the nine months ended September 30, 2002, electricity sales were 95.2 TWh compared to 106.6 TWh last year. The decrease in volumes was primarily due to lower sales resulting from the decontrol of generation from the Bruce Nuclear Generating Stations. Upon the closing of the operating lease agreement with Bruce Power, OPG was obligated to purchase and resell all of Bruce Power's electricity generation up to the date of market opening. Upon market opening, Bruce Power began selling electricity directly into the IMO-administered real-time energy market, thereby lowering OPG's sales revenue and volumes. Electricity sales volumes also decreased since OPG is no longer required to purchase electricity to meet market demand through an obligation to serve.

Fuel and Power Purchases

Total Energy Available (TWh) for Generation Segment	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2002	**2001**	**2002**	**2001**
Production				
Nuclear:				
Darlington & Pickering	**10.9**	10.1	**32.2**	30.1
Bruce (1)	**-**	-	**-**	8.6
Total Nuclear	**10.9**	10.1	**32.2**	38.7
Fossil	**10.6**	10.9	**28.7**	30.9
Hydroelectric	**7.4**	6.8	**26.8**	24.0
Total Production	**28.9**	27.8	**87.7**	93.6
Power Purchased (2)	**-**	7.9	**7.4**	13.7
Other (3)	**-**	0.1	**0.1**	(0.7)
Total Energy Available	**28.9**	35.8	**95.2**	106.6

(1) Represents generation from Bruce Nuclear Generating Stations prior to decontrol.
(2) OPG had a commitment to purchase all of Bruce Power's electricity generation up to May 1, 2002, the date of market opening, as part of the lease agreement for the Bruce Nuclear Generating Stations.
(3) Represents deposits and withdrawals of electricity with utilities in neighbouring jurisdictions under energy banking arrangements.

Fuel expense for the third quarter of 2002 was $412 million compared to a fuel expense of $393 million for the same period in 2001. The increase of $19 million was primarily due to higher coal costs, partially offset by the impact of lower production at OPG's fossil-fuelled generating stations.

Fuel expense for the first nine months of 2002 was $1,147 million compared to $1,099 million in 2001, an increase of $48 million. The increase was primarily due to higher coal costs and an increase in the Gross Revenue Charge ("GRC") as a result of higher hydroelectric production, partially offset by the impact of lower production at the fossil-fuelled generating stations and a reduction in nuclear fuel related to the decontrol of the Bruce generating stations. 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.

Power purchased during the third quarter 2002 was nil compared with $374 million for the same period in 2001. The decrease was primarily due to the elimination of purchases from Bruce Power, since purchases from Bruce Power ended upon market opening, and the fact that OPG is no longer required to purchase electricity to meet Ontario market demand through an obligation to serve. Power purchased from Bruce Power during the third quarter of 2001 was 6.5 TWh.

Power purchased during the first nine months of 2002 was $290 million compared with $649 million for the same period in 2001, based on purchases of 7.4 TWh in 2002 and 13.7 TWh in 2001. The decrease was primarily due to lower purchases of electricity from Bruce Power, and the elimination of OPG's requirement to purchase electricity to meet Ontario market demand. OPG purchased 6.8 TWh of electricity from Bruce Power during the period from January 1 to April 30, 2002, compared to 10.2 TWh from May 11 to September 30, 2001.

Operating Expenses

Operation, maintenance and administration ("OM&A") expenses were $569 million for the third quarter of 2002 compared with $579 million for the same period in 2001, a decrease of $10 million. The decrease was primarily due to lower pension and other post employment benefit ("OPEB") expenses of $17 million and a one-time reduction of $24 million 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. These decreases were partially offset by higher expenditures related to the return to service of the Pickering A nuclear generating station of $13 million and increases in other expenses of $18 million.

OM&A expenses were $1,747 million for the nine months ended September 30, 2002 compared with $1,818 million for the same period in 2001, a decrease of $71 million. The decrease in OM&A expenses for the nine-month period was primarily due to reduced operating expenses from the decontrol of the Bruce Nuclear Generating Stations of $112 million, lower pension and OPEB expenses of $42 million, the WSIB settlement of $24 million, and a decrease in other expenses of $25 million primarily due to lower nuclear outage costs and completion of nuclear recovery programs. These decreases were partially offset by higher expenditures related to the return to service of the Pickering A nuclear generating station of $108 million and increases in other expenses of $24 million.

Property and Capital Taxes

The property and capital taxes for the nine months ended September 30, 2002 were $79 million compared to $43 million for the same period last year. The increase in property and capital taxes was primarily due to the effect of a property tax refund received during 2001.

Energy Marketing Segment

Since 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 related primarily to physical energy that is purchased and sold at the Ontario border, but also included financial products to manage the financial risk of the physical transactions. Previously, OPG's energy marketing activity was not a reportable business segment. Accordingly, there are no comparative amounts for 2001.

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2002	**2001**	**2002**	**2001**
Revenue	**67**	-	**86**	-
Power purchased	**36**	-	**54**	-
Gross margin	**31**	-	**32**	-
Operation, maintenance and administration	**1**	-	**3**	-
Operating income	**30**	-	**29**	-

OPG has implemented comprehensive trade capture and risk management systems and processes to identify and measure risk related to energy marketing activities. Appropriate position and risk limits have been established for performance and risk management purposes. The value at risk ("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% confidence interval, ranged between $1.1 million to $1.5 million during the third quarter of 2002.

Non-Energy and Other

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2002	**2001**	**2002**	**2001**
Revenue	**77**	82	**240**	160
Operation, maintenance and administration	**11**	24	**43**	43
Depreciation and amortization	**35**	23	**80**	40
Property and capital taxes	**3**	2	**9**	3
Restructuring costs	**12**	-	**222**	-
Loss on transition rate option contracts	**-**	-	**210**	-
Operating income	**16**	33	**(324)**	74
Other income	**11**	-	**117**	-
Net interest expense	**36**	31	**114**	102
Income (loss) before income taxes	**(9)**	2	**(321)**	(28)

Revenue

Non-energy revenue was $77 million for the third quarter of 2002 compared to $82 million for the same period last year. Non-energy revenue for the nine months ended September 30, 2002 was $240 million compared to $160 million for the same period in 2001, an increase of $80 million. The increase in non-energy revenue for the nine months ended September 30, 2002 was primarily due to an increase in lease and ancillary revenue earned under the agreements with Bruce Power.

Restructuring Costs

In 2001, OPG approved a restructuring plan designed to improve OPG's future cost competitiveness. Completion of significant decontrol activities and completion of other major initiatives over the next two years requires the restructuring of areas within OPG that support these operations. Restructuring charges are related to an anticipated reduction in the workforce of approximately 2,000 employees over a two to three year period. As at September 30, 2002, OPG has accepted applications for voluntary severance packages from approximately 1,400 employees.

Restructuring charges include severance costs and related pension and other post employment benefit expenses. A restructuring charge of $67 million was recorded in the fourth quarter of 2001. The provision was increased by $210 million in the first quarter of 2002 and by $12 million in the third quarter of 2002, for a total increase of $222 million during the nine months ended September 30, 2002. The $12 million increase in the third quarter relates to additional severance costs for terminated employees. The restructuring liability at September 30, 2002 reflected employee departures over a period not exceeding twelve months.

The total cost of the restructuring plan is expected to be approximately $400 million. During the third quarter of 2002, there were severance payments of $23 million related to restructuring. For the nine months ended September 30, 2002, $95 million was paid.

Loss on Transition Rate Options

Under a regulation known as Transition – Generation Corporation Rate Options (“TRO”), OPG is required to provide transitional price relief upon market opening to certain large 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 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 related to the future loss on these contracts. The provision was determined 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. These estimates are subject to measurement uncertainty. For the three months ended September 30, 2002, $25 million has been charged to the provision and included in generation revenue. Since the market opened on May 1, 2002, $43 million has been charged against the provision and included in generation revenue.

Other Income

Other income includes the gain on sale from decontrol activities and other initiatives. Other income was $11 million for the third quarter of 2002 and $117 million for the nine months ended September 30, 2002.

In May 2002, OPG completed the sale of four hydroelectric generating stations located on the Mississagi River to Great Lakes Hydro Income Fund. OPG received cash proceeds of $342 million from the sale and recorded a pretax gain of $99 million. In addition, OPG recorded gains totalling $18 million comprised of the third quarter sale of OPG’s Nuclear Safety Assessment Division and the first quarter sales of OPG’s investments in New Horizon Systems Solutions and Kinectrics Inc.

INCOME TAX

For the nine-month period ended September 30, 2002, the effective income tax rate increased to 49% in 2002 from 37% in 2001. The 2001 tax rate was lower primarily due to the one-time impact of the reduction in future taxes resulting from the decrease in the future income tax rates announced last year. The 2001 third quarter results reflected a reduction in the effective income tax rate as a result of favourable income tax treatment for certain other revenues that arose in 2001.

RESTATEMENT OF THIRD QUARTER 2001 FOR PENSIONS AND OTHER POST EMPLOYMENT BENEFITS (OPEB)

At year-end 2001, OPG changed its policy of accounting for changes in the net actuarial gain or loss for pension and OPEB. This change in accounting policy results in amortization of the net cumulative unamortized gain or loss in excess of 10% of the greater of the benefit obligation and the market-related value of the plan assets. Previously, the entire change in the net actuarial gain or loss was amortized over the employee average remaining service life and plan assets were valued at market for purposes of determining actuarial gains and losses. The change in accounting policy for pensions and OPEB was applied retroactively to April 1, 1999. As a result of this change, the operating results for the nine months ended September 30, 2001 have been restated to reflect an increase in employee benefit expense of $25 million and a decrease in net income of $28 million.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the third quarter ended September 30, 2002 was $446 million compared to cash flow used in operating activities of $24 million in the same period in 2001, an increase in cash flow of $470 million. The increase in cash flow was primarily due to higher energy prices which reflected higher summer demand and warmer than normal temperatures. Under the market power mitigation agreement, a rebate will be paid to the IMO for ultimate distribution to customers.

Cash flow provided from operating activities for the nine months ended September 30, 2002 was $534 million compared to $177 million for the same period in 2001, an increase of $357 million. The increase in cash flow was mainly due to higher energy prices contributing to the market power mitigation agreement rebate, partially offset by other changes in non-cash working capital.

With market opening, electricity prices are expected to have 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 operations.

During the nine months ended September 30, 2002, the fixed asset removal and nuclear waste management funds increased by a total of $288 million compared to $322 million for the same period in 2001. OPG made lower contributions in 2002 in order to adjust for overcontributions in previous years. The balance in the fund at September 30, 2002 was $1,496 million.

Capital expenditures for the third quarter were $209 million compared to $181 million for the same period in 2001. For the nine-month period ended September 30, 2002, capital expenditures were $575 million compared to $450 million for the same period last year. The increase in capital expenditures was primarily due to higher activity related to the return to service of the Pickering A nuclear generating station and expenditures related to the installation of selective catalytic reduction equipment associated with emissions reductions at OPG’s Lambton and Nanticoke fossil generating stations. OPG is presently conducting a review of its inventory at Pickering to identify any obsolete spare parts and materials resulting from the significant design changes and refurbishment of the Pickering A nuclear generating station.

In March 2002, OPG renewed its revolving short-term committed credit facility. The amount of the credit facility was increased from $600 million to $1,000 million. The credit facility 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, 2002, OPG had no amounts outstanding under the CP program. The Company plans to access the capital markets with a debt offering over the next six to nine months.

In May 2002, Dominion Bond Rating Service lowered OPG's senior unsecured long-term debt rating to A (low) from A and confirmed the Commercial Paper rating of R-1 (low). The trend on both ratings remains stable. In July 2002, Standard and Poor's reaffirmed OPG's long-term debt rating of BBB+ while changing the outlook to negative and lowering the short-term debt rating to A-2 from A-1(low).

The Company paid dividends of $134 million during the nine months ended September 30, 2002 compared with $238 million for the same period in 2001. The decrease in dividends reflected a dividend in 2001 related to proceeds received from the decontrol of the Bruce Nuclear Generating Stations and other dividends to achieve a 35 per cent pay out of actual 2001 earnings.

Under the market power mitigation agreement rebate mechanism, the Company will be required to pay a rebate to the IMO equal to the excess of the average hourly spot energy price over 3.8¢/kWh for a twelve month settlement period, multiplied by the amount of energy subject to the rebate mechanism. The first settlement period ends April 30, 2003. OPG expects to pay the rebate to the IMO in June 2003, however, the timing of payment is subject to change. The amount of the rebate payable to the IMO in 2003 for the twelve-month settlement period ending April 30, 2003 will be dependent on average spot prices over the settlement period.

During the third quarter of 2002, Brighton Beach Power L.P., a limited partnership between ATCO Power Ltd. and OPG, completed a $403 million private bond and term debt financing for its 580 megawatt power project under construction at Brighton Beach in Windsor, Ontario. As of September 30, 2002, $276 million was outstanding under the financing agreement. OPG proportionately consolidates its 50% interest in the partnership and accordingly $138 million is included in OPG's long-term debt. Brighton Beach is scheduled to be in-service by the end of the first quarter in 2004.

PICKERING A RETURN TO SERVICE

OPG is continuing to progress with the safety and environmental upgrades and other refurbishment work which is required prior to the return to service of the four units at the Pickering A nuclear generating station. Expenditures on the return to service initiative through the end of September 2002, which include the cost of common operating systems for all four units, total approximately $1,025 million, approximately two-thirds of which have been expensed. Progress on the first unit to return to service has been somewhat slower than expected as a result of construction challenges encountered in the refurbishment of certain systems. Commissioning of the first unit is estimated to begin in the latter part of the first quarter of 2003. The additional cost to complete the first unit is estimated at approximately $230 million. The cost and schedule to return the remaining units to service will be reassessed based on OPG's experience with the first unit returning to service, in order to determine the appropriateness of the $300 to $400 million estimate per unit, as previously reported. Pickering A will add 2,060 MW of reliable, low cost electricity and will make a significant contribution towards improving environmental performance within the Ontario electricity sector.

RISK MANAGEMENT

Ontario's electricity market opened to competition on May 1, 2002. With market opening, OPG is subject to increased risk, including market and credit risk inherent in a deregulated market. The Board of Directors has approved governance policies, structures and limits to facilitate the management of the increased risk. A Risk Oversight Committee, which consists of senior officers of OPG, has been established to approve markets, products, monitor policies and compliance issues, and ensure the continuing effectiveness of overall corporate governance under the direction of the Board of Directors and within limits approved by the Board.

In anticipation of increased levels of risk and complexity of market activities, OPG implemented a comprehensive trade capture and risk management system with related processes and controls. OPG's commercial activities are separated into portfolios to capture the risks inherent in each transaction for each portfolio. This process facilitates the effective identification and measurement of risks, and the application of appropriate position and risk limits for performance and risk management purposes. The methodology used to measure these risks includes the use of consistent and recognized risk measures for monitoring trading activities and the generation portfolio. Open trading positions are subject to measurement against value at risk 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% confidence interval. OPG's approved VaR limit is $5 million.

Electricity Price Risk

Electricity price risk is the risk that changes in the market price of electricity will adversely impact OPG's earnings and cash flow from operations. OPG faces price risk directly related both to the demand and supply of generation in the open market and transmission constraints. OPG's production is exposed to spot market prices. However, derivative instruments and related risk management products may be used to mitigate OPG's exposure to volatile electricity prices.

Credit Risk

Credit risk is the financial risk of non-performance by contractual counterparties. 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 actively manages its exposures through the enforcement of an established counterparty credit policy. OPG manages counterparty credit risk through dealing with investment grade counterparties, monitoring and limiting its exposure to counterparties with lower credit ratings, active collateral management, and by avoiding excessive concentration to any one counterparty or category of counterparties. Credit exposures include both settlement and market-based components. OPG's credit exposure is concentrated in the physical market with the IMO.

Since the Ontario market opened on May 1, the monthly credit exposures to the IMO have fluctuated between $425 million and $1.1 billion. OPG's management believes that the IMO is an acceptable 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 in the financial instrument market. 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:

(millions of dollars) Credit Rating [1]	Potential Exposure [2]	Number of Counterparties	Net Exposure for 10 Largest Counterparty Exposures
AAA to AA	16	5	-
A+ to A-	219	33	171
BBB+ to BBB-	147	40	57
BB+ to BB-	26	17	-
B- to B+	20	11	15
Total	428	106	243
IMO	687	1	687
	1,115	107	930

[1] Credit rating classifications are based on external rating agency analysis where available, or based on OPG's own analysis.
[2] Potential exposure represents OPG's assessment of the maximum exposure over the life of each transaction.

Bruce Power is obligated to pay OPG certain amounts as specified under the lease agreement for the Bruce Nuclear Generating Stations as well as various ancillary service agreements. Bruce Power's parent Company, British Energy PLC, is experiencing financial difficulties which could have an impact on Bruce Power's liquidity and operations. OPG is closely monitoring the situation. To date, Bruce Power has made all payments in a timely manner. At September 30, 2002, OPG had a note receivable from Bruce Power of $225 million, accounts receivable of approximately $61 million and long-term liabilities and other payables due to Bruce Power of approximately $136 million and $38 million respectively, resulting in a net credit exposure of $112 million. Management believes that its security interest and the rights under the lease arrangements, including repossession rights, minimize OPG's potential financial exposure to a default by Bruce Power or British Energy. After taking into account OPG's security interest in the lease, deferred revenue related to the Bruce transaction of $189 million and capital improvements made by Bruce Power, OPG is satisfied that an event of default by Bruce Power would not have a material impact on the Company.

Generation Risk

OPG is exposed to the market impacts of uncertain output from its generating units or generation risk. The amount of electricity generated by OPG is affected by such risks as fuel supply, equipment malfunction, maintenance requirements, and regulatory and environmental constraints. To mitigate earnings volatility due to generation risk, OPG enters into multiple short-term and long-term fuel supply agreements and long-term water use agreements, manages fuel supply inventories, and follows industry practices for maintenance and outage scheduling. In addition, OPG ensures regulatory requirements are met, particularly with respect to licencing of its nuclear facilities, and manages environmental constraints utilizing programs such as emission reduction credits to manage the supply of generation.

Liquidity Risk

OPG operates in a capital-intensive business. Significant financial resources are required to return the Pickering A station to service and to fund other improvement projects and potential expenditures necessary to comply with air emission or other regulatory requirements. As well, funds are required for payments under the restructuring initiative, the market power mitigation agreement rebate, contributions to the Used Fuel Fund under the Ontario Nuclear Funds Agreement, and other obligations including expected funding of OPG's pension fund commencing in 2003.

The Company's liquidity is highly dependent on its debt rating. A change in the rating could result in additional collateral requirements with counterparties depending on the mark to market value of the contracts. In particular, where counterparties are in a positive mark to market position and OPG is in a negative position, a downgrade to OPG could trigger increased collateral requirements based on the provisions of the contract. At September 30, 2002, the majority of energy contracts have a net positive mark to market position. As a result, a downgrade would not significantly affect the Company's collateral requirements based on current market prices.

OPG's ability to arrange debt financing and the costs of new borrowings are dependent on a number of factors including: general economic and capital market conditions; credit availability from banks and other financial institutions; maintenance of acceptable credit ratings; and the status of electricity market restructuring in Ontario. OPG believes cash flows from operations, the short-term committed credit facility and the successful issue of debt in the capital markets should provide adequate liquidity for OPG's requirements.

Foreign Exchange and Interest Rate Risk

OPG's foreign exchange risk exposure is attributable primarily to U.S. dollar-denominated transactions such as the purchase of fossil fuel and the purchase and sale of electricity in U.S. markets. OPG currently manages its net exposure by periodically hedging portions of its net anticipated U.S. dollar cash flows according to approved risk management policies.

Interest rate exposure for OPG is limited by the fixed rates on its long-term debt. Interest rate risk arises with the need to undertake new financing and with the potential addition of variable rate debt. Interest rate risk may be hedged using derivative instruments. The management of these risks is undertaken by selectively hedging in accordance with corporate risk management policies.

COMPARATIVE INFORMATION

In 2001, the Province of Ontario introduced a Gross Revenue Charge ("GRC") derived from the annual generation of electricity from hydroelectric generating stations. Beginning in the second quarter of 2002, OPG classified all of the GRC payments as fuel expense. Previously, GRC payments were charged to fuel expense and property tax expense. As a result of this change, $53 million has been reclassified for comparative purposes as fuel expense from property tax expense for the third quarter of 2001. For the nine months ended September 30, 2001, $144 million has been reclassified for comparative purposes to fuel expense from property tax expense.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this quarterly report are forward-looking and reflect the Company's views with respect to future events. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Forward-looking statements are not guarantees of the Company's future performance or results and are subject to various factors, including, but not limited to, assumptions regarding the nuclear recovery plan, nuclear waste management and decommissioning, fuel procurement, fuel costs, Ontario electricity industry restructuring, market power mitigation, environmental regulations, spot market electricity prices, and effects of weather. Although the Company believes that assumptions inherent in forward-looking statements are reasonable, undue reliance should not be placed on these statements, which apply only as of their dates. The Company is not obligated to update or revise any forward-looking statements, 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**		**Nine Months Ended September 30**	
		Restated *(note 5)*		**Restated *(note 5)***
	2002	**2001**	**2002**	**2001**
Revenues	**1,648**	1,635	**4,486**	4,681
Fuel	**412**	393	**1,147**	1,099
Power purchased	**36**	374	**344**	649
Gross Margin	**1,200**	868	**2,995**	2,933
Operating expenses				
Operation, maintenance and administration	**581**	603	**1,793**	1,861
Depreciation and amortization	**188**	202	**566**	606
Property and capital taxes	**29**	2	**88**	46
Restructuring costs *(note 6)*	**12**	-	**222**	-
Loss on transition rate option contracts *(note 4)*	**-**	-	**210**	-
	810	807	**2,879**	2,513
Operating income	**390**	61	**116**	420
Other income *(note 11)*	**11**	-	**117**	-
Net interest expense	**36**	31	**114**	102
Income before income taxes	**365**	30	**119**	318
Income taxes (recoveries) *(note 13)*				
Current	**131**	(175)	**86**	97
Future	**19**	124	**(28)**	21
	150	(51)	**58**	118
Net income	**215**	81	**61**	200
Basic and diluted earnings per common share (dollars)	**0.84**	0.32	**0.24**	0.78
Common shares outstanding (millions)	**256.3**	256.3	**256.3**	256.3

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (UNAUDITED)

(millions of dollars)	**Nine Months Ended September 30**	
		Restated *(note 5)*
	2002	**2001**
Retained earnings, beginning of period as previously reported	**344**	691
Adjustment *(note 5)*	**-**	(124)
Retained earnings, **beginning of period as restated**	**344**	567
Net income	**61**	200
Dividends	**(134)**	(238)
Retained earnings, end of period	**271**	529

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(millions of dollars)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
		Restated *(note 5)*		**Restated *(note 5)***
	2002	**2001**	**2002**	**2001**
Operating activities				
Net income	**215**	81	**61**	200
Adjust for non-cash items:				
Depreciation and amortization	**188**	202	**566**	606
Deferred pension asset	**(1)**	4	**3**	40
Other post employment benefits	**7**	23	**59**	80
Future income taxes	**19**	124	**(28)**	21
Provision for restructuring	**12**	-	**222**	-
Transition rate option contracts *(note 4)*	**(25)**	-	**167**	-
Gain on sale of investments	**(11)**	-	**(18)**	-
Gain on sale of decontrol fixed assets	**-**	-	**(99)**	-
Mark to market on energy contracts *(note 9)*	**6**	-	**4**	-
Other	**33**	23	**99**	46
	443	457	**1,036**	993
Contributions to fixed asset removal and nuclear waste management fund	**(128)**	(105)	**(288)**	(322)
Expenditures on nuclear waste management	**(17)**	(15)	**(69)**	(38)
Expenditures on restructuring	**(23)**	-	**(95)**	-
Net changes to other long-term assets and liabilities	**(56)**	(49)	**(129)**	(87)
Deferred revenue	**(22)**	(8)	**(29)**	(10)
Changes in non-cash working capital balances*(note 14)*	**249**	(304)	**108**	(359)
Cash flow provided by (used in) operating activities	**446**	(24)	**534**	177
Investing activities				
Proceeds from Bruce decontrol *(note 10)*	**-**	-	**-**	370
Net proceeds from short-term investments	**-**	(12)	**39**	214
Proceeds on sale of decontrol fixed assets *(note 10)*	**-**	2	**342**	12
Cash proceeds from sale of investments *(note 11)*	**15**	-	**29**	-
Purchases of fixed assets	**(209)**	(181)	**(575)**	(450)
Cash flow provided by (used in) investing activities	**(194)**	(191)	**(165)**	146
Financing activities				
Issuance of long-term debt (note 7)	**138**	-	**138**	-
Repayment of long-term debt	**(1)**	(100)	**(1)**	(200)
Dividends paid	**-**	(138)	**(134)**	(238)
Short-term notes issued	**35**	-	**235**	-
Short-term notes repaid	**(35)**	-	**(235)**	(50)
Cash flow provided by (used in) financing activities	**137**	(238)	**3**	(488)
Net increase (decrease) in cash and cash equivalents	**389**	(453)	**372**	(165)
Cash and cash equivalents, beginning of period	**(17)**	853	**-**	565
Cash and cash equivalents, end of period	**372**	400	**372**	400
Supplementary disclosures				
Interest paid	**95**	98	**191**	199
Income taxes paid	**-**	61	**50**	132

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED*)*

(millions of dollars)	**September 30 2002**	**December 31 2001**
Assets		
Current assets		
Cash and cash equivalents	**372**	-
Short-term investments	**-**	39
Accounts receivable	**811**	1,010
Income taxes recoverable	**11**	77
Fuel inventory	**577**	537
Materials and supplies	**54**	35
	1,825	1,698
Fixed assets		
Property, plant and equipment	**14,735**	14,460
Less: accumulated depreciation	**1,888**	1,479
	12,847	12,981
Other assets		
Deferred pension asset	**303**	330
Fixed asset removal and nuclear waste management fund *(note 8*)	**1,496**	1,208
Long-term note receivable *(note 10)*	**225**	225
Materials and supplies	**210**	179
Long-term accounts receivable and other assets	**102**	65
	2,336	2,007
	17,008	16,686
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(notes 3, 4)*	**1,660**	1,505
Deferred revenue due within one year	**13**	13
Long-term debt due within one year *(note 7)*	**205**	205
	1,878	1,723
Long-term debt *(note 7)*	**3,152**	3,015
Other liabilities		
Fixed asset removal and nuclear waste management *(note 8)*	**4,872**	4,724
Other post employment benefits	**947**	924
Long-term accounts payable and accrued charges *(notes 4, 10)*	**335**	336
Deferred revenue	**176**	215
Future income taxes *(note 13)*	**251**	279
	6,581	6,478
Shareholder's equity		
Common shares	**5,126**	5,126
Retained earnings	**271**	344
	5,397	5,470
	17,008	16,686

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2002 (UNAUDITED)
(Tabular amounts in million of dollars except as otherwise noted)

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, 2001. Certain comparative amounts have been reclassified to conform with the 2002 financial statement presentation.

2. Accounting Policies

Market Power Mitigation Agreement Rebate

OPG is required under its generating licence to comply with prescribed market power mitigation measures to address the potential for OPG to exercise market power in Ontario. The market power mitigation measures are a rebate mechanism and the requirement to decontrol generating capacity. Under the rebate mechanism, for the first four years after market opening, a significant majority of OPG's expected energy sales in Ontario are 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 a twelve month settlement period, multiplied by the amount of energy subject to the rebate mechanism. The first settlement period ends April 30, 2003. The quantities of energy subject to the rebate, as well as the hourly weights used to compute the annual average spot price for rebate purposes, have been fixed in advance but may be reduced for decontrol transactions. 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.

Energy Contracts for Open Market

OPG is exposed to changes in electricity prices associated with an open spot market for electricity in Ontario. To hedge the commodity price risk exposure associated with changes in the price of electricity, OPG has entered into various energy and related sales contracts. These contracts are expected to be effective as hedges of the commodity price exposure on OPG's generation portfolio**.** Gains or losses on hedging instruments are recognized over the term of the contract when the underlying hedged transactions occur and are included in generation revenue. All contracts that are not designated as hedges are valued at market value with changes in fair value recorded in energy marketing revenue as gains or losses.

Derivative financial instruments and related risk management products are utilized by the Company in accordance with its Risk Policy and within defined corporate risk tolerances. Transactions may only be initiated with approved counterparties within assigned credit limits and subject to approvals. As a result of these procedures, the Company does not believe the failure of any counter-parties to these derivatives would have a material impact on its operations.

Emission Reduction Credits

OPG utilizes emission reduction credits ("ERCs") to manage acid gas emissions (Nitrogen Oxide, Sulphur Dioxide and Carbon Dioxide) within the prescribed regulatory limits and voluntary limits. ERCs are purchased from trading partners in Canada and the United States. The cost of ERCs are held in inventory and charged to OPG's operations as part of fuel as required. Options to purchase ERC's are accounted for as derivatives and are valued at estimated market value.

Transmission Rights

Transmission rights ("TRs") are option contracts issued by the IMO that provide protection for importers and exporters against differences between the Ontario market clearing price for energy and the intertie clearing price. Price differences can occur due to limits on transmission capacity between Ontario and the interconnected markets at a specific intertie. OPG purchases TRs in the Ontario market. TRs are accounted for as derivatives used for energy marketing purposes and valued at estimated market value. Changes in fair value are recorded as energy marketing gains or losses.

Taxes

Under the *Electricity Act, 1998,* OPG is responsible for making payments in lieu of corporate income and capital taxes to the Ontario Electricity Financial Corporation ("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.*

The Company is also required to pay property taxes. OPG makes payments in lieu of property tax on its nuclear and fossil generating assets to the OEFC, and also pays property taxes to municipalities.

OPG pays charges on gross revenue derived from the annual generation of electricity from its hydroelectric generating assets. The Gross Revenue Charge ("GRC") includes a fixed percentage charge applied to the annual hydroelectric generation derived from stations located on provincial crown lands, in addition to graduated rate charges applicable to all hydroelectric stations. GRC costs are included in fuel expense.

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 eliminate a portion of the market power mitigation agreement rebate obligation ("Decontrol Mitigation").

In May 2001, OPG completed the agreement to lease its Bruce Nuclear Generating Stations to Bruce Power L.P. and in May 2002, completed the sale of four of its hydroelectric stations located on the Mississagi River to Great Lakes Hydro Income Fund. OPG has filed an application with the OEB seeking a reduction in the amount of energy sales subject to the rebate mechanism as a result of the decontrol of the Bruce Nuclear Generating Stations and is in the process of preparing an application related to the sale of the Mississagi River stations. The Company believes that it has met all of the requirements for the transfer of effective control and therefore will receive a reduction in energy sales subject to the market power mitigation agreement rebate. OEB approval of the applications would result in a reduction in volumes subject to the market power mitigation agreement rebate for the twelve month settlement period ending April 30, 2003 from 101.8 TWh to 81.4 TWh.

Since the average hourly spot price since May 1, 2002 has exceeded the 3.8¢/kWh revenue cap, OPG has recorded a liability at September 30, 2002 equal to the excess of the average hourly spot energy price over 3.8¢/kWh, multiplied by the amount of energy subject to the rebate mechanism. As at September 30, 2002, the Company had deferred 1.779¢/kWh on a volume of 31.7 TWh. The rebate liability was 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.

OPG expects to receive a decision from the OEB regarding the Decontrol Mitigation during the first quarter of 2003. If OPG's application is not approved, revenue in the period in which the determination is made would be decreased by the amount of the Decontrol Mitigation which totalled approximately $110 million at September 30, 2002.

4. Transition Rate Options

Under a regulation known as Transition – Generation Corporation Rate Options ("TRO"), OPG is required to provide transitional price relief upon market opening to certain large 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 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 related to the future loss on these contracts. The provision was determined 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. These estimates are subject to measurement uncertainty. As a result, 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 September 30, 2002, $25 million was charged to the provision. Since market opening on May 1, 2002, the provision has been reduced by $43 million. At September 30, 2002, the current portion of the provision for loss on these contracts was $110 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 $57 million.

5. Restatement of 2001 Quarterly Results for Pension and Other Post Employment Benefits

In 2001, OPG changed its policy of accounting for changes in the net actuarial gain or loss for pension and OPEB. This change in accounting policy results in the amortization of the net cumulative unamortized gain or loss in excess of 10 per cent of the greater of the benefit obligation and the market-related value of the plan assets. Previously, the entire change in the net actuarial gain or loss was amortized over employee average remaining service life and plan assets were valued at market for purposes of determining actuarial gains and losses. The change in accounting policy for pensions and OPEB was applied retroactively to April 1, 1999. As a result of this change, the operating results for the nine months ended September 30, 2001 have been restated to reflect an increase in employee benefit expenses of $25 million and a decrease in net income of $28 million.

Opening retained earnings at January 1, 2001 were reduced by $124 million due to the change in accounting policy for pension and OPEB ($104 million), as well as a revision to OPEB resulting from an assessment of OPG's claims history for 2000 ($20 million).

6. Restructuring Costs

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 of approximately 2,000 employees over a two to three year period. Restructuring charges of $67 million and $210 million were recorded in the fourth quarter of 2001 and the first quarter of 2002, respectively. The restructuring charges included severance costs of $242 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 provision for severance was increased by $12 million in the third quarter to record additional severance costs for terminated employees, resulting in total restructuring charges of $222 million for 2002. The total cost of the restructuring plan is expected to be approximately $400 million.

The following table provides a summary of the transactions pertaining to the restructuring liability for severance:

	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2002
Balance, beginning of period	**170**	40
Restructuring charges	**12**	214
Payments	**(23)**	(95)
Balance, end of period	**159**	159

7. Long-term Debt

In March 2002, the Company reached an agreement with the OEFC to defer to December 2004, $200 million principal amount of senior notes maturing in 2002. In connection with this deferral, the coupon rate on $100 million principal amount of these notes was increased, based on commercial terms, by 0.50 per cent; the interest rate for the remaining $100 million principal amount of these notes was unchanged.

During the third quarter of 2002, Brighton Beach Power L.P., a limited partnership between ATCO Power Ltd. and OPG, completed a $403 million private bond and term debt financing for its 580 megawatt power project under construction in Windsor, Ontario. As of September 30, 2002, $276 million was outstanding under the loan and accordingly $138 million is shown on OPG's books. OPG proportionately consolidates its 50 per cent interest in the Brighton Beach Power partnership. If the partnership does not complete the project by September 30, 2006, OPG is required to repurchase its proportionate share of the outstanding debt up to a total of $201.5 million. OPG is also responsible for contributing its share of equity (up to 10 per cent of project costs) and up to $12.5 million of cost overruns as necessary.

8. Fixed Asset Removal and Nuclear Waste Management Liabilities

Nuclear Funds Agreements

In March 2002, the Province of Ontario (the "Province") and OPG signed the Ontario Nuclear Funds Agreement (the "Agreement"). The Agreement establishes criteria for the management of segregated funds and limits OPG's financial exposure to the risk of cost increases for certain used fuel liabilities, subject to graduated liability thresholds. Under the terms of the Agreement, OPG will establish two custodial funds that will be held separate from OPG's operations. The Used Fuel Fund will be used to fund future costs of nuclear used fuel waste management. The Decommissioning Fund will be established to fund the future cost of nuclear fixed asset removal and low and intermediate level waste management. The Agreement will become effective when the two custodial funds are established, expected some time during the fourth quarter of 2002 .

Since April 1, 1999, OPG has contributed $1,496 million including interest earned of $161 million to the nuclear fixed asset removal and nuclear waste management fund. The Decommissioning Fund will be funded through a receivable due from the Ontario Electricity Financial Corporation ("OEFC"), with the balance funded through OPG's existing segregated funds. The remaining segregated funds will be applied to the Used Fuel Fund. OPG will make annual contributions to the Used Fuel Fund of approximately $450 million to 2008, and a reduced amount over the remaining life of the nuclear generating stations.

OPG will continue to bear the risk and liability for cost increases and fund earnings with respect to nuclear fixed asset removal and low and intermediate level waste management. OPG will also continue to be responsible for the risk and liability for cost increases for used fuel waste management, subject, however, to graduated liability thresholds specified in the agreement which limit OPG's total financial exposure.

As required by the *Nuclear Safety and Control Act* (Canada), and under the terms of the Agreement, the Province will provide to the Canadian Nuclear Safety Commission ("CNSC"), a guarantee that there will be funds available to discharge the nuclear decommissioning and waste liabilities. This guarantee is expected to relate to the portion of the nuclear liabilities not funded by the Decommissioning and Used Fuel funds, or by the OEFC receivable, and will be determined based on CNSC requirements. The terms and conditions of the guarantee are subject to the approval of the Minister of Finance.

In June 2002, the *Nuclear Fuel Waste Act* (Canada) received Royal Assent. Under the Act, owners of nuclear fuel waste are required to form a waste management organization to address and provide recommendations on long-term management of nuclear fuel waste. In addition, under the Act, OPG will be required to make an initial deposit of $500 million into a trust fund within ten days of the Act coming into force and $100 million for each of the three years thereafter. The Company will provide such funds by way of transfer from existing segregated funds and from its annual contributions to segregated funds. The Act will come into effect when proclaimed into force, which is expected in the fourth quarter of 2002.

Cost Estimate Changes Made in 2002

OPG reviewed the significant assumptions that underlie the calculation of the accrued liabilities for fixed asset removal and nuclear waste management liabilities. As a result of this review, a number of assumptions were revised to reflect changes in the timing of certain programs and in the evolving technology used to handle the nuclear waste. These changes included a delay in the in-service date for used nuclear fuel disposal facilities from 2025 to 2035, the recognition of certain costs associated with dry storage of used nuclear fuel during station operating life, and recognition of additional costs related to nuclear waste management programs. In aggregate, these cost estimate changes would result in a net reduction to the nuclear waste management and decommissioning liability of $215 million. In accordance with Canadian generally accepted accounting principles, the change in liability is being amortized over the average remaining service life of the nuclear generating stations. As a result of this change, for the nine months ended September 30, 2002, $12 million was recorded as a decrease to the liability and a reduction to expenses.

9. Derivative Financial Instruments

The tables below provide a summary of the fair value of OPG's derivative instruments. The first table relates to derivative instruments that are not hedges. These derivatives are carried on the balance sheet as assets or liabilities at fair value, with changes in fair value recognized in energy marketing revenue.

The second table relates to derivative instruments designated as hedges. The Company uses financial commodity derivatives primarily to fix the price for electricity sales. Gains or losses on these derivative hedging instruments are recognized in income over the term of the contract when the underlying transactions occur and are not recorded on the balance sheet.

The Company uses foreign exchange derivative instruments primarily to hedge its net exposure to anticipated US dollar denominated purchases. Foreign exchange translation gains and losses on these foreign currency denominated financial instruments are recognized as an adjustment to the purchase price of the commodity or goods received.

Fair values have been estimated by reference to quoted market prices for actual or similar instruments where available. Where quoted market prices are not available, OPG develops internal models for prices, based on available market data. 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.

	September 30, 2002		**December 31, 2001**
	Notional Quantity	**Fair Value**	**Fair Value**
Carrying amount (fair value) of contracts not used for hedging purposes			
Commodity derivative instruments			
Assets	**10.8 TWh**	**3**	**-**
Liabilities	**2.9 TWh**	**(15)**	**-**
Total		**(12)**	**-**

At September 30, 2002, the fair value of commodity derivative instruments not used for hedging purposes consists of a $12 million liability related to legacy contracts from the previous market structure, and transmission rights and other short-term contracts with a fair value of nil. The income statement impact of these transactions was reduced by the reversal, upon market opening, of a contract loss provision recorded as at December 31, 2001.

	September 30, 2002			December 31, 2001		
	Notional quantity	**Terms**	**Fair Value**	**Notional quantity**	**Terms**	**Fair Value**
Fair value of derivative contracts designated as hedges						
Commodity derivative instruments						
Electricity	44 TWh	**1-5 yrs**	**86**	14 TWh	1-5 yrs	-
Foreign exchange derivative instruments	$229 US	**Apr/03**	**6**	$147 US	Mar/02	3
Option to purchase emission reduction credits	2,000,000 tonnes	**2003-2004**	**-**	-	-	-

10. Decontrol Initiatives

Bruce Nuclear Generating Stations

In May 2001, the Company completed the close of the operating lease agreement to lease its Bruce A and Bruce B nuclear generating stations to Bruce Power until 2018, with an option to renew for 25 years. As part of the initial payment, OPG received $370 million in cash proceeds and a $225 million note receivable. The receivable of $225 million is payable to OPG in two installments of $112.5 million no later than four and six years from the date the transaction was completed. Interest is currently charged on the initial payment at a rate of 10.5 per cent, escalating over time to 18 per cent annually. The interest is recorded as non-energy revenue.

Under the terms of the lease, OPG agreed to transfer certain fuel and material inventory to Bruce Power, in addition to certain fixed assets. OPG also agreed to transfer pension assets and liabilities related to the approximately 3,000 employees who transferred from OPG to Bruce Power. Bruce Power assumed the liability for other post employment benefits for these employees. OPG will pay Bruce Power, in respect of other post employment benefits, payments of approximately $2.3 million per month over a 72-month period ending in 2008.

As part of the closing, OPG recorded $230 million of deferred revenue to reflect the initial payment less net assets transferred to Bruce under the lease agreement. The deferred revenue is being amortized over the initial lease term of approximately 18 years and is recorded as non-energy revenue.

During the third quarter ended September 30, 2002, OPG and Bruce Power settled certain remaining outstanding matters related to the lease of the Bruce Nuclear Generating Stations totalling $22 million. For the nine months ended September 30, 2002, total post closing adjustments with respect to this transaction were $29 million.

As part of the lease agreement, OPG receives annual lease payments from Bruce Power. The lease payments consist of monthly fixed payments and supplemental payments based on the number of operating units. The supplemental lease payment structure has been modified, with effect from May 2001, to replace the original net revenue-sharing arrangement. The lease payments are made semi-annually and are recorded in non-energy revenue.

Bruce Power's parent Company, British Energy PLC, is experiencing financial difficulties which could impact on Bruce Power's liquidity and operations. OPG is closely monitoring the situation. At September 30, 2002, OPG had a note receivable from Bruce Power of $225 million, accounts receivable of approximately $61 million and long-term liabilities and other payables due to Bruce Power of approximately $136 million and $38 million respectively. Management believes that its security interest and the rights under the lease arrangements, including repossession rights, minimize OPG's potential financial exposure to a default by Bruce Power or British Energy.

Decontrol of Mississagi River Stations

In March 2002, OPG announced the sale of four hydroelectric generating stations located on the Mississagi River, to Great Lakes Hydro Income Fund. The sale closed on May 17, 2002. OPG received cash proceeds of $342 million from the sale and recorded a pretax gain of $99 million.

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 the current market conditions in the 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 financial statements.

11. 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**	
	2002	2001	**2002**	2001
Mississagi River generating stations	**-**	-	**99**	-
Investment in Kinectrics Inc.	**-**	-	**3**	-
Investment in New Horizon Systems Solutions Inc.	**-**	-	**4**	-
Nuclear Safety Assessment Division	**11**	-	**11**	-
	11	-	**117**	-

Sale of Investment in Kinectrics Inc.

In February 2002, OPG sold its remaining ownership interest in Kinectrics Inc. to AEA Technology plc for approximately $12 million in cash proceeds. The Company recorded a gain on the sale of Kinectrics of $3 million.

Sale of Investment in New Horizon Systems Solutions Inc.

In March 2002, OPG divested its 49 per cent joint venture interest in New Horizon System Solutions Inc. ("New Horizon") to Business Transformation Services Inc., a wholly owned subsidiary of Cap Gemini Ernst & Young. OPG entered into a nine-year information technology outsourcing agreement with New Horizon in order to continue to gain access to a broad spectrum of IT services in infrastructure and operations management. The Company recorded a gain on sale of $4 million.

Sale of Nuclear Safety Assessment Division

During the third quarter 2002, the Company completed the sale of its Nuclear Safety Analysis Division to Nuclear Safety Systems, a subsidiary of National Nuclear Corporation. Total proceeds from the sale were approximately $20 million consisting of cash proceeds of approximately $15 million and assumption of other liabilities of approximately $5 million. The Company recorded a gain of approximately $11 million.

12. Other Items

WSIB Settlement

For purposes of the Worker's Safety and Insurance Board of Ontario ("WSIB"), OPG was reclassified from a schedule 2 self-insured employer to a schedule 1 premium-paying employer. During the third quarter, the WSIB assumed the liability with respect to OPG's existing and future worker's compensation claims in exchange for a cash payment of $54.5 million. Accordingly a settlement of the entire obligation has occurred and the Company recorded a one-time reduction in OM&A expenses of $24 million.

13. Income Taxes

For the nine-month period ended September 30, 2002, the effective income tax rate increased to 49 per cent in 2002 from 37 per cent in 2001. The 2001 tax rate was lower primarily due to the one-time impact of the reduction in future taxes resulting from the decrease in the future income tax rates announced last year. The 2001 third quarter results reflected a reduction in the effective income tax rate as a result of favourable income tax treatment for certain other revenues that arose in 2001.

14. Changes in Non-Cash Working Capital Balances

	Three Months Ended September 30		**Nine Months Ended September 30**	
	2002	**2001**	**2002**	**2001**
Accounts receivable	**(388)**	23	201	155
Income tax recoverable	**143**	-	66	-
Fuel inventory	**8**	(79)	(40)	(77)
Materials and supplies	**-**	2	(19)	(57)
Accounts payable and accrued charges	**486**	(250)	(100)	(380)
	249	(304)	108	(359)

15. Segment Disclosures

Description of Reportable Segments

With the opening of Ontario's electricity market to competition on May 1, 2002, OPG began operating a second reportable business segment referred to as the Energy Marketing segment. OPG now has two reportable segments: Generation and Energy Marketing. OPG also derives non-energy revenue under the terms of the lease arrangement with Bruce Power, including lease revenue, interest income and revenue from engineering analysis and design, technical and ancillary services. Non-energy revenue also includes isotope sales and gains and losses from decontrol activities.

Generation Segment

OPG's principal business segment operates in Ontario generating and selling electricity. Commencing 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, black start capability 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.

Energy Marketing Segment

The Energy Marketing segment derives revenues 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 spot market sales and trading, the sale of bilateral risk management products and sales of energy-related products and services to meet customers' needs for energy solutions. The results of transactions in derivatives not designated as hedges of energy prices are included in the Energy Marketing segment. OPG also markets and sells electricity into the interconnected markets of other provinces and the U.S. northeast and midwest. Previously, OPG's energy marketing activity was not a reportable business segment. Accordingly, there are no comparative values for 2001.

Reported Segment Income

3 months ended September 30, 2002	**Generation**	**Energy Marketing**	**Non-Energy & Other**	**Total**
Revenue	1,504	67	77	1,648
Fuel	412	-	-	412
Power purchased	-	36	-	36
Gross margin	1,092	31	77	1,200
Operation, maintenance and administration	569	1	11	581
Depreciation and amortization	153	-	35	188
Property and capital taxes	26	-	3	29
Restructuring costs	-	-	12	12
Operating income (loss)	344	30	16	390
Other income	-	-	11	11
Net interest expense		-	36	36
Income before income taxes	344	30	(9)	365

3 months ended September 30, 2001	**Generation**	**Energy Marketing**	**Non-Energy & Other**	**Total**
Revenue	1,553	-	82	1,635
Fuel	393	-	-	393
Power purchased	374	-	-	374
Gross margin	786	-	82	868
Operation, maintenance and administration	579	-	24	603
Depreciation and amortization	179	-	23	202
Property and capital taxes	-	-	2	2
Operating income (loss)	28	-	33	61
Net interest expense	-	-	31	31
Income before income taxes	28	-	2	30

9 months ended September 30, 2002	Generation	Energy Marketing	Non-Energy & Other	Total
Revenue	4,160	86	240	4,486
Fuel	1,147	-	-	1,147
Power purchased	290	54	-	344
Gross margin	2,723	32	240	2,995
Operation, maintenance and administration	1,747	3	43	1,793
Depreciation and amortization	486	-	80	566
Property and capital taxes	79	-	9	88
Restructuring costs	-	-	222	222
Loss on transition rate option contracts	-	-	210	210
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

9 months ended September 30, 2001	Generation	Energy Marketing	Non-Energy & Other	Total
Revenue	4,521	-	160	4,681
Fuel	1,099	-	-	1,099
Power purchased	649	-	-	649
Gross margin	2,773	-	160	2,933
Operation, maintenance and administration	1,818	-	43	1,861
Depreciation and amortization	566	-	40	606
Property and capital taxes	43	-	3	46
Operating income (loss)	346	-	74	420
Net interest expense	-	-	102	102
Income before income taxes	346	-	(28)	318

Selected Balance Sheet Information

September 30, 2002				
Segment property, plant & equipment	11,909	-	938	12,847
December 31, 2001				
Segment property, plant & equipment	12,026	-	955	12,981

Selected Cash Flow Information

3 months ended September 30, 2002				
Capital expenditures	209	-	-	209
3 months ended September 30, 2001				
Capital expenditures	180	-	1	181
9 months ended September 30, 2002				
Capital expenditures	575	-	-	575
9 months ended September 30, 2001				
Capital expenditures	447	-	3	450

16. Seasonal Operations

The Company's quarterly results are impacted by changes in demand resulting from variations in seasonal weather conditions. Historically, the Company's revenues are higher in the first and third quarters of a fiscal year as a result of winter heating demands in the first quarter and air conditioning/cooling demands in the third quarter. The market power mitigation agreement rebate and the Company's hedging strategies significantly reduce the impact of seasonal price fluctuations on the Company's operations.

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