

## CONSOLIDATED STATEMENTS OF INCOME (LOSS) (UNAUDITED)

	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2005	2004	2005	2004
<i>(millions of dollars except where noted)</i>				
<b>Revenue</b>				
Revenue before Market Power Mitigation Agreement and revenue limit rebates	1,514	1,349	3,284	3,140
Market Power Mitigation Agreement rebate (note 13)	-	(208)	(412)	(649)
Revenue limit rebate (note 14)	(141)	-	(141)	-
	<b>1,373</b>	1,141	<b>2,731</b>	2,491
Fuel expense	289	242	599	580
<b>Gross margin</b>	<b>1,084</b>	899	<b>2,132</b>	1,911
<b>Expenses</b>				
Operations, maintenance and administration	616	633	1,203	1,257
Depreciation and amortization (note 4)	192	194	385	386
Accretion on fixed asset removal and nuclear waste management liabilities	120	114	239	227
Earnings on nuclear fixed asset removal and nuclear waste management funds	(112)	(80)	(183)	(178)
Property and capital taxes	17	30	38	58
Restructuring	-	16	-	16
	<b>833</b>	907	<b>1,682</b>	1,766
<b>Operating income</b>	<b>251</b>	(8)	<b>450</b>	145
Impairment of long-lived assets (note 4)	63	-	265	-
<b>Income (loss) before interest, income taxes and extraordinary item</b>	<b>188</b>	(8)	<b>185</b>	145
Net interest expense	47	45	94	90
<b>Income (loss) before income taxes and extraordinary item</b>	<b>141</b>	(53)	<b>91</b>	55
Income tax (recoveries) expenses				
Current	7	(2)	14	6
Future (note 2)	(3)	(10)	(22)	26
	<b>4</b>	(12)	<b>(8)</b>	32
<b>Income (loss) before extraordinary item</b>	<b>137</b>	(41)	<b>99</b>	23
<b>Extraordinary item (note 2)</b>	<b>74</b>	-	<b>74</b>	-
<b>Net income (loss)</b>	<b>63</b>	(41)	<b>25</b>	23
<b>Basic and diluted income (loss) per common share (dollars)</b>	<b>0.25</b>	(0.16)	<b>0.10</b>	0.09
<b>Common shares outstanding (millions)</b>	<b>256.3</b>	256.3	256.3	256.3

See accompanying notes to the interim consolidated financial statements

## CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (UNAUDITED)

### Six Months Ended June 30

*(millions of dollars)*

	<u>2005</u>	<u>2004</u>
<b>(Deficit) retained earnings, beginning of period</b>	<b>(105)</b>	<b>(147)</b>
Net income (loss)	<u>25</u>	<u>23</u>
<b>(Deficit), end of period</b>	<b><u>(80)</u></b>	<b><u>(124)</u></b>

*See accompanying notes to the interim consolidated financial statements*

## CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

<i>(millions of dollars)</i>	Three Months Ended June 30		Six Months Ended June 30	
	2005	2004	2005	2004
<b>Operating activities</b>				
Net income (loss)	63	(41)	25	23
Adjust for non-cash items:				
Depreciation and amortization	192	194	385	386
Accretion on fixed asset removal and nuclear waste management liabilities	120	114	239	227
Earnings on nuclear fixed asset removal and nuclear waste management funds	(112)	(80)	(183)	(178)
Pension cost	28	23	56	46
OPEB and supplementary pension	46	41	91	81
Future income taxes	(3)	(10)	(22)	26
Transition rate option contracts	(9)	(9)	(18)	(26)
Provision for restructuring	-	16	-	16
Mark-to-market on energy contracts	2	4	4	5
Provision for used nuclear fuel	6	6	13	15
Impairment of long-lived assets	63	-	265	-
Extraordinary item	74	-	74	-
Other	1	2	-	6
	<b>471</b>	<b>260</b>	<b>929</b>	<b>627</b>
Contributions to nuclear fixed asset removal and nuclear waste management funds	(113)	(113)	(227)	(227)
Expenditures on fixed asset removal and nuclear waste management	(25)	(18)	(39)	(31)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management	4	8	10	8
Contributions to pension fund	(39)	(38)	(78)	(76)
Expenditures on OPEB and supplementary pension	(17)	(16)	(33)	(30)
Expenditures on restructuring <i>(note 11)</i>	(4)	(1)	(9)	(43)
Net changes to other long-term assets and liabilities	(20)	(19)	(29)	(19)
Changes in non-cash working capital balances <i>(note 16)</i>	(184)	(209)	(151)	(132)
<b>Cash flow provided by (used in) operating activities</b>	<b>73</b>	<b>(146)</b>	<b>373</b>	<b>77</b>
<b>Investing activities</b>				
Investment in regulatory assets <i>(note 2)</i>	(90)	-	(191)	-
Investment in fixed assets	(106)	(127)	(240)	(223)
<b>Cash flow (used in) investing activities</b>	<b>(196)</b>	<b>(127)</b>	<b>(431)</b>	<b>(223)</b>
<b>Financing activities</b>				
Issuance of long-term debt <i>(note 6)</i>	400	5	495	13
Repayment of long-term debt <i>(note 6)</i>	(1)	(2)	(2)	(4)
Net decrease in short-term notes <i>(note 5)</i>	-	-	(26)	-
<b>Cash flow provided by financing activities</b>	<b>399</b>	<b>3</b>	<b>467</b>	<b>9</b>
<b>Net increase (decrease) in cash and cash equivalents</b>	<b>276</b>	<b>(270)</b>	<b>409</b>	<b>(137)</b>
<b>Cash and cash equivalents, beginning of period</b>	<b>135</b>	<b>419</b>	<b>2</b>	<b>286</b>
<b>Cash and cash equivalents, end of period</b>	<b>411</b>	<b>149</b>	<b>411</b>	<b>149</b>

See accompanying notes to the interim consolidated financial statements

## CONSOLIDATED BALANCE SHEETS (UNAUDITED)

<i>(millions of dollars)</i>	<b>June 30 2005</b>	<b>December 31 2004</b>
<b>Assets</b>		
<b>Current assets</b>		
Cash and cash equivalents	411	2
Accounts receivable <i>(note 3)</i>	397	346
Future income taxes	44	44
Fuel inventory	496	569
Materials and supplies	118	92
	<b>1,466</b>	<b>1,053</b>
<b>Fixed assets <i>(note 4)</i></b>		
Property, plant and equipment	14,966	15,114
Less: accumulated depreciation	3,434	3,174
	<b>11,532</b>	<b>11,940</b>
<b>Other long-term assets</b>		
Deferred pension asset	546	524
Nuclear fixed asset removal and nuclear waste management funds <i>(note 7)</i>	6,376	5,976
Long-term materials and supplies	291	281
Regulatory assets <i>(note 2)</i>	191	-
Long-term accounts receivable and other assets	57	56
	<b>7,461</b>	<b>6,837</b>
	<b>20,459</b>	<b>19,830</b>

See accompanying notes to the interim consolidated financial statements

**CONSOLIDATED BALANCE SHEETS (UNAUDITED)**

<i>(millions of dollars)</i>	<b>June 30 2005</b>	<b>December 31 2004</b>
<b>Liabilities</b>		
<b>Current liabilities</b>		
Accounts payable and accrued charges <i>(notes 11 and 12)</i>	834	949
Market Power Mitigation Agreement rebate payable <i>(note 13)</i>	245	439
Revenue limit rebate payable <i>(note 14)</i>	141	-
Short-term notes payable <i>(note 5)</i>	-	26
Long-term debt due within one year <i>(note 6)</i>	305	5
Deferred revenue due within one year	12	12
Income and capital taxes payable	23	12
	<b>1,560</b>	<b>1,443</b>
<b>Long-term debt <i>(note 6)</i></b>	<b>3,592</b>	<b>3,399</b>
<b>Other long-term liabilities</b>		
Fixed asset removal and nuclear waste management <i>(note 7)</i>	8,555	8,339
OPEB and supplementary pension	1,163	1,105
Long-term accounts payable and accrued charges	186	212
Deferred revenue	150	156
Future income taxes	207	155
	<b>10,261</b>	<b>9,967</b>
<b>Shareholder's equity</b>		
Common shares	5,126	5,126
Deficit	(80)	(105)
	<b>5,046</b>	<b>5,021</b>
	<b>20,459</b>	<b>19,830</b>

Commitments and Contingencies *(notes 1, 4, 5, 9, and 10)*

See accompanying notes to the interim consolidated financial statements

## NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2005 AND 2004 (UNAUDITED)

### 1. BASIS OF PRESENTATION

These interim consolidated financial statements were prepared following the same accounting policies and methods as in the most recent annual consolidated financial statements, except as discussed in Note 2 to the interim consolidated financial statements. However, these interim 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, 2004.

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

Certain of the 2004 comparative amounts have been reclassified from financial statements previously presented to conform to the 2005 financial statement presentation.

The consolidated financial statements include the accounts of Ontario Power Generation Inc. and its subsidiaries. OPG accounts for its interests in jointly controlled entities using the proportionate consolidation method. All significant inter-company transactions have been eliminated on consolidation.

### 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

#### Changes in Accounting Policies

##### *Rate Regulated Accounting*

In December 2004, the *Electricity Restructuring Act, 2004* received Royal Assent. A regulation made pursuant to that statute prescribes that OPG's nuclear and baseload hydroelectric facilities will receive regulated prices for their output. Accounting standards recognize that rate regulation can create economic benefits and obligations, which are reported in the consolidated financial statements as regulatory assets and liabilities. If the regulation provides assurance that incurred costs will be recovered in the future, then a regulated entity may defer those costs and report them as a regulatory asset. If current recovery is provided for costs expected to be incurred in the future, then a regulated entity reports a regulatory liability.

Effective January 1, 2005, in accordance with regulations pursuant to the *Electricity Restructuring Act, 2004*, OPG is required to establish a deferral account in connection with non-capital costs that are associated with the return to service of units at the Pickering A nuclear generating station. Since this section of the regulation became effective January 1, 2005, the change in accounting was prospectively adopted on that date, with no retroactive adoption. As at June 30, 2005, the deferral account was \$191 million, consisting of non-capital costs of \$179 million relating to Unit 1 and \$10 million relating to Units 2 and 3, and interest, accreted at the average cost of debt of 6.0 per cent, of \$2 million. Upon OPG becoming regulated by the Ontario Energy Board ("OEB") in 2008, the OEB is directed by the regulation to ensure that OPG recovers any balance in the deferral account on a straight-line basis over a period not to exceed 15 years.

Effective April 1, 2005, in accordance with the regulations pursuant to the *Electricity Restructuring Act, 2004*, OPG was directed to establish a variance account for costs incurred on or after April 1, 2005 that are associated with differences in hydroelectric electricity production due to differences between forecast and actual water conditions, changes in nuclear electricity production due to unforeseen changes to the law or to unforeseen technological changes, changes to revenues assumed for ancillary revenues from the regulated facilities, acts of God (including severe weather events), and transmission outages and

transmission restrictions. OPG recorded a liability as at June 30, 2005 of \$4 million, reflecting water conditions that were favourable compared to those forecasted for the second quarter of 2005. Upon OPG becoming regulated by the Ontario Energy Board ("OEB") in 2008, the OEB is directed by the regulation to review the recovery and settlement of any balances established by OPG. Any balances approved by the OEB will be amortized on a straight-line basis over a period not to exceed three years.

### *Taxes*

Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes related to the rate regulated segments of the business using the taxes payable method, as permitted for rate regulated operations. OPG continues to use the liability method of accounting for income taxes for its unregulated business only.

Under the taxes payable method, OPG will not be recognizing future income taxes related to the rate regulated segments of the business to the extent that these income taxes are expected to be recovered in the regulated rates charged to future customers. As a result, on April 1, 2005, OPG reversed the future income tax asset balance of \$74 million relating to the rate regulated segments of the business, and recognized the amount as an extraordinary loss in determining net income. Had OPG continued to use the liability method for the regulated business, the future tax expense for the three months ended June 30, 2005 would have increased by \$53 million, with a corresponding increase in the future income tax liability. As at June 30, 2005, the future income tax liability would have been \$186 million.

Under the liability method, income taxes are recognized as a result of temporary differences arising from the difference between the tax basis of an asset or liability and its carrying value in the balance sheet, the carry-forward of unused tax losses and income tax reductions. Future income tax assets and liabilities are measured using income tax rates expected to apply in the years in which temporary differences are expected to reverse. The effect on future income tax assets and liabilities of a change in tax rates is included in income in the period the change is substantively enacted. Future income tax assets are evaluated and if realization is not considered more likely than not, a valuation allowance is established.

The extraordinary item reduced basic and diluted earnings per share for the three and six month periods ended June 30, 2005 by \$0.28.

### **New Accounting Recommendations**

#### *Consolidation of Variable Interest Entities*

In September 2004, the CICA amended Accounting Guideline 15, *Consolidation of Variable Interest Entities*, originally issued in June 2003, to harmonize with the revised Financial Accounting Standards Board ("FASB") Interpretation No. 46, *Consolidation of Variable Interest Entities* ("FIN 46R"). The new guideline requires the consolidation of variable interest entities ("VIEs") by the primary beneficiary. A VIE is an entity where (a) its equity investment at risk is insufficient to permit the entity to finance its activities without additional subordinated support from others and/or where certain essential characteristics of a controlling financial interest are not met, and (b) it does not meet specified exemption criteria. The primary beneficiary is the enterprise that will absorb or receive the majority of the VIEs' expected losses, expected residual returns, or both.

OPG is involved with various joint venture and other arrangements and has sold trade receivables under an asset securitization arrangement. The Company assessed these arrangements in advance of the guideline becoming effective January 1, 2005. OPG concluded that the joint venture arrangements with which it is involved are not VIEs, and that it is not the primary beneficiary of, nor does it have a significant variable interest in, the trust to which it sold trade receivables. OPG has completed the review of its other arrangements and determined that there is no impact on OPG's existing accounting for these arrangements.

### 3. SALE OF ACCOUNTS RECEIVABLE

On October 1, 2003, the Company signed an agreement to sell an undivided co-ownership interest in its current and future accounts receivable (the "receivables") to an independent trust. The Company also retains an undivided co-ownership interest in the receivables sold to the trust. Under the agreement, OPG continues to service the receivables. The transfer provides the trust with ownership of a share of the payments generated by the receivables, computed on a monthly basis. The trust's recourse to the Company is generally limited to its income earned on the receivables.

OPG reflected the initial transfer to the trust of the co-ownership interest, and subsequent transfers required by the revolving nature of the securitization, as sales in accordance with CICA Accounting Guideline 12, *Transfer of Receivables*. In accordance with this Guideline, the proceeds of each sale to the trust were deemed to be the cash received from the trust net of the undivided co-ownership interest retained by the Company. For the three months ended June 30, 2005, the Company has recognized pre-tax charges of \$2 million (three months ended June 30, 2004 – \$2 million) on such sales at an average cost of funds of 2.9 per cent (three months ended June 30, 2004 – 2.3 per cent). For the six months ended June 30, 2005, the Company has recognized pre-tax charges of \$4 million (six months ended June 30, 2004 – \$4 million) on such sales at an average cost of funds of 2.9 per cent (six months ended June 30, 2004 – 2.5 per cent). As at June 30, 2005, OPG had sold receivables of \$300 million from its total portfolio of \$567 million.

### 4. FIXED ASSETS

Depreciation and amortization expense for the three and six months ended June 30, 2005 and 2004 consists of the following:

<i>(millions of dollars)</i>	Three Months Ended June 30		Six Months Ended June 30	
	2005	2004	2005	2004
Depreciation and amortization	190	193	382	383
Nuclear waste management costs	2	1	3	3
	192	194	385	386

Interest capitalized to construction in progress at 6.0 per cent during the three and six months ended June 30, 2005 (three and six months ended June 30, 2004 – 6.0 per cent) was \$9 million and \$17 million respectively (three and six months ended June 30, 2004 – \$9 million and \$17 million).

#### Impairment of Long-Lived Assets

The accounting estimates related to asset impairment require significant management judgment to identify factors such as short and long-term forecasts for future sales prices, the supply of electricity in Ontario, the return to service dates of laid-up generating stations, inflation, fuel prices and station lives. The amount of the future cash flow that OPG will ultimately realize with respect to these assets could differ materially from the carrying values recorded in the consolidated financial statements.

#### *Pickering A Nuclear Generating Station Units 2 and 3*

OPG recently completed an assessment of the cost, schedule and risks related to the return to service of Units 2 and 3 at the Pickering A nuclear generating station. This included an assessment of the ability of these units to perform at an acceptable capability factor over the remaining 12 to 20 years of operations. This assessment incorporated recent findings from inspection programs with respect to feeder pipe and steam generator degradation mechanisms, and potential degradation of the calandria vault components, all of which could impact the future capability factor, operating costs and the life of the units. Upon consideration of the scope of the refurbishment work, the costs and the risks related to the return to service of these two units, and the Company's focus on improving the performance of its other nuclear units, OPG's Board of Directors decided that while technically feasible, the return to service of these units

was not justified on a commercial basis. Accordingly, OPG recorded an impairment loss in the second quarter of 2005 related to the carrying amount of these two units including construction in progress, which was \$63 million at June 30, 2005.

OPG expects to recover the amounts recorded in the deferral account relating to non-capital costs incurred after January 1, 2005 associated with the return to service of Units 2 and 3. As at June 30, 2005, the deferral account relating to Units 2 and 3 was \$10 million.

As a result of the decision not to proceed with the return to service of these two units, OPG will have to assess the need to provide for any additional costs, including the cost associated with preparing the units for safe storage, any impacts on cost estimates for asset retirement obligation, any excess inventory, and any other additional exit costs. These potential additional charges are not specifically determinable at this time, however a detailed assessment of these associated costs will be completed during the remainder of 2005. Such charges may have a significant impact on operating results in future periods.

#### *Lennox Generating Station*

As a result of the Government's "Request for Information/Request for Proposal for 2,500 MW of New Clean Generation and Demand Side Management Projects" released in September 2004 and the related contractual arrangements, future wholesale electricity market revenue is expected to be lower than previously anticipated. As a relatively high variable cost plant, the Lennox generating station will not be able to recover its fixed operating costs and its carrying value from the wholesale electricity market in the future. Given these factors, OPG had initiated discussions with the Province, with the expectation of entering into a contractual arrangement for the recovery of the annual fixed operating costs and the carrying value of the Lennox generating station. In March 2005, OPG was advised by the Province that it would continue to support OPG in negotiating an arrangement that would allow for the recovery of fixed operating costs, but that the Province would not support an arrangement that would allow for the recovery of the carrying value of the Lennox generating station. As a result of this change in circumstance, OPG recorded the impairment loss of \$202 million in the first quarter of 2005. OPG has since negotiated an arrangement with the Independent Electricity System Operator ("IESO") to recover its fixed operating costs for a one-year period ending July 31, 2006. The arrangement with the IESO is subject to approval by the OEB.

#### **5. SHORT-TERM CREDIT FACILITIES**

OPG's current 364-day term \$1,000 million revolving committed bank credit facility was renewed on May 24, 2005. The new facility is divided into two tranches – a \$500 million 364-day term tranche maturing May 23, 2006, and a \$500 million three-year term tranche maturing May 23, 2008. The total credit facility will continue to be used primarily as support for notes issued under OPG's commercial paper program. As at June 30, 2005, OPG had no borrowings outstanding under this commercial paper program (December 31, 2004 – \$26 million). As at June 30, 2005 and December 31, 2004, OPG had no other outstanding borrowing under this facility.

OPG also maintains \$26 million (December 31, 2004 – \$26 million) in short-term uncommitted overdraft facilities as well as \$213 million (December 31, 2004 – \$200 million) of short-term uncommitted credit facilities, which support the issuance of Letters of Credit. OPG uses Letters of Credit to support the supplementary pension plan, and is required to post the Letters of Credit as collateral with Local Distribution Companies ("LDCs") as prescribed by the Ontario Energy Board's ("OEB") Retail Settlement Code. At June 30, 2005, there were approximately \$158 million (December 31, 2004 – \$155 million) of Letters of Credit issued for the supplementary pension plan and collateral requirements to the LDCs.

## 6. LONG-TERM DEBT

Long-term debt consists of the following:

<i>(millions of dollars)</i>	<b>June 30 2005</b>	<b>December 31 2004</b>
Notes payable to the OEFC	<b>3,695</b>	3,200
Capital lease obligations	<b>1</b>	3
Share of non-recourse limited partnership debt	<b>201</b>	201
	<b>3,897</b>	3,404
Less: due within one year		
Notes payable to the OEFC	<b>300</b>	-
Capital lease obligations	<b>1</b>	3
Share of limited partnership debt	<b>4</b>	2
	<b>305</b>	5
Long-term debt	<b>3,592</b>	3,399

Holders of the senior debt are entitled to receive, in full, amounts owing in respect of the senior debt before holders of the subordinated debt are entitled to receive any payments. The Ontario Electricity Financial Corporation ("OEFC") currently holds all of OPG's outstanding senior and subordinated notes.

In December 2004, OPG reached an agreement with the OEFC to defer payment on \$500 million principal amount of senior notes maturing in March and September 2005 by extending the maturity dates by five years. The interest rates remain unchanged. In March 2005, the Company reached an agreement with the OEFC to obtain additional financing up to \$600 million, which can be drawn until March 31, 2006. In April 2005, \$400 million was drawn under this facility, with a seven year term.

The Company also reached an agreement with the OEFC to satisfy, through the issue of additional senior notes of \$95 million and \$98 million respectively, to mature in 2010, its \$95 million interest obligation due in March 2005 and the \$98 million interest obligation due in September 2005 related to the debt owing to the OEFC of \$3.2 billion.

Interest paid during the three months ended June 30, 2005 was \$16 million (three months ended June 30, 2004 – \$7 million), of which \$10 million relates to interest paid on long-term debt (three months ended June 30, 2004 – \$4 million). Interest paid during the six months ended June 30, 2005 was \$119 million (six months ended June 30, 2004 – \$111 million), of which \$110 million relates to interest paid on long-term debt (six months ended June 30, 2004 – \$105 million). Interest on the notes payable to the OEFC is paid in the first and third quarters of the year.

## 7. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT

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

<i>(millions of dollars)</i>	<b>June 30 2005</b>	<b>December 31 2004</b>
Liability for nuclear used fuel management	<b>4,821</b>	4,693
Liability for nuclear decommissioning and low and intermediate level waste management	<b>3,544</b>	3,457
Liability for non-nuclear fixed asset removal	<b>190</b>	189
Fixed asset removal and nuclear waste management liability	<b>8,555</b>	8,339

The change in the fixed asset removal and nuclear waste management liability for the six months ended June 30, 2005 and year ended December 31, 2004, is as follows:

<i>(millions of dollars)</i>	<b>June 30 2005</b>	<b>December 31 2004</b>
Liability, beginning of period	<b>8,339</b>	7,921
Increase in liability due to accretion	<b>239</b>	453
Increase in liability due to nuclear used fuel and nuclear waste management variable expenses	<b>16</b>	35
Fixed asset removal of partnership interests	-	1
Liabilities settled by expenditures on waste management	<b>(39)</b>	(71)
Liability, end of period	<b>8,555</b>	8,339

### Ontario Nuclear Funds Agreement

OPG sets aside funds to be used specifically for discharging its nuclear fixed asset removal and nuclear waste management liabilities. The nuclear fixed asset removal and nuclear waste management funds as at June 30, 2005 and December 31, 2004, consist of the following:

<i>(millions of dollars)</i>	<b>Amortized Cost Basis</b>		<b>Fair Value</b>	
	<b>June 30 2005</b>	<b>December 31 2004</b>	<b>June 30 2005</b>	<b>December 31 2004</b>
Decommissioning Fund	<b>3,973</b>	3,858	<b>4,313</b>	4,131
Used Fuel Fund <sup>1</sup>	<b>2,403</b>	2,118	<b>2,403</b>	2,118
	<b>6,376</b>	5,976	<b>6,716</b>	6,249

<sup>1</sup> The Ontario NFWA Trust represents \$924 million as at June 30, 2005 (December 31, 2004 – \$794 million) of the Used Fuel Fund on an amortized cost basis.

### 8. BENEFIT PLANS

The post employment benefit programs include pension, group life insurance, health care and long-term disability benefits. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, changes in assumptions and experience gains or losses. The 2005 costs are based on a measurement of the pension and OPEB obligations and the pension fund assets, at December 31, 2004.

Total benefit costs for the three and six months ended June 30, 2005 and 2004, are as follows:

<i>(millions of dollars)</i>	<b>Three Months Ended June 30</b>		<b>Six Months Ended June 30</b>	
	<b>2005</b>	<b>2004</b>	<b>2005</b>	<b>2004</b>
Registered pension plan	<b>28</b>	23	<b>56</b>	46
Supplementary pension plan	<b>5</b>	4	<b>9</b>	8
OPEB	<b>41</b>	37	<b>82</b>	73

## 9. FINANCIAL INSTRUMENTS

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

Trading activities and liquidity in the Ontario electricity market have been limited as companies are generally entering only into short-term contracts. As a result, forward pricing information for contracts may not accurately represent the cost to enter into these contracts. For Ontario-based contracts that are not entered into for hedging purposes, OPG established liquidity reserves against the fair market value of the assets and liabilities equal to the gain or loss on these contracts. These reserves increased trading revenue by \$7 million during the six months ended June 30, 2005 (six months ended June 30, 2004 – \$2 million). Contracts for transactions outside of Ontario continue to be carried on the consolidated balance sheets as assets or liabilities at fair value, with changes in fair value recorded in trading revenue as gains or losses.

### *Derivative Instruments Used for Hedging Purposes*

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

<i>(millions of dollars except where noted)</i>	<b>Notional Quantity</b>	<b>Terms</b>	<b>Fair Value</b>	<b>Notional Quantity</b>	<b>Terms</b>	<b>Fair Value</b>
	<b>June 30, 2005</b>			<b>December 31, 2004</b>		
(Loss)/gain						
Electricity derivative instruments	<b>6.0 TWh</b>	<b>1-3 yrs</b>	<b>(101)</b>	10.4 TWh	1-3 yrs	(71)
Foreign exchange derivative instruments	<b>US \$8</b>	<b>July/05</b>	-	US \$10	Jan/05	-

Foreign exchange derivative instruments are used to hedge the exposure to anticipated U.S. dollar denominated purchases. The weighted average fixed exchange rate for contracts outstanding at June 30, 2005 was US \$0.82 (December 31, 2004 – US \$0.81) for every Canadian dollar.

### *Derivative Instruments Not Used for Hedging Purposes*

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

<i>(millions of dollars except where noted)</i>	<b>Notional Quantity</b>	<b>Fair Value</b>	<b>Notional Quantity</b>	<b>Fair Value</b>
	<b>June 30, 2005</b>		<b>December 31, 2004</b>	
Commodity derivative instruments				
Assets	<b>5.9 TWh</b>	<b>6</b>	7.9 TWh	12
Liabilities	<b>1.7 TWh</b>	<b>(19)</b>	1.3 TWh	(12)
		<b>(13)</b>		-
Ontario market liquidity reserve		-		(7)
<b>Total</b>		<b>(13)</b>		(7)

## 10. COMMITMENTS AND CONTINGENCIES

### Litigation and Claims

Various lawsuits are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of its business activities. In July 2004, OPG was charged with criminal negligence causing death and criminal negligence causing bodily harm in relation to a 2002 accident at Barrett Chute. Also, certain First Nations have commenced actions for interference with reserve and traditional land rights. The claims by some of these First Nations total approximately \$50 million and claims by others are for unspecified amounts. Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably with respect to OPG. These contingencies are provided for when they are likely to occur and are reasonably estimable. Management believes that the ultimate resolution of these matters will not have a material effect on OPG's financial position.

OPG has become aware, very recently, of a class action suit that has been issued against it and 20 U.S.-based electricity generators relating to the use of coal as fuel at some of its facilities. The merits, if any, will be determined in a timely and appropriate manner.

### Guarantees

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

OPG has provided limited guarantees in connection with its share of the Brighton Beach financing, whereby it is responsible for contributing its share of equity related to cost overruns associated with the construction of the generating station. As at June 30, 2005, OPG met its obligations for contributing its share of equity related to cost overruns. As Brighton Beach commenced commercial operation in July 2004, any cost overruns are now primarily limited to settlement of construction liens registered by some contractors associated with the construction project. Brighton Beach arranged an independent third party review of the claims and is now actively negotiating final settlement of these liens.

## 11. RESTRUCTURING

The change in the restructuring liability for termination benefits for the six months ended June 30, 2005 and year ended December 31, 2004 is as follows:

<i>(millions of dollars)</i>	<b>June 30 2005</b>	<b>December 31 2004</b>
Liability, beginning of period	<b>20</b>	52
Restructuring charges	-	19
Payments	<b>(9)</b>	(51)
Liability, end of period	<b>11</b>	20

During 2004, OPG recorded restructuring charges of \$16 million, which consisted of \$15 million for termination benefits and \$1 million in related pension and OPEB expenses associated with its Lakeview generating station. OPG also recorded restructuring charges of \$4 million related to its Energy Marketing segment during 2004.

## 12. TRANSITION RATE OPTION CONTRACTS

Under regulation known as Transition – Generation Corporation Designated Rate Options (“TRO”), OPG has been required to provide transitional price relief since market opening to certain power customers for up to four years based on the consumption and average price paid by each customer during a reference period of July 1, 1999 to June 30, 2000. The TRO is treated as a hedge of generation revenue. The maximum anticipated volume subject to the transitional price relief was approximately 5.4 TWh in the first year after market opening and 3.6 TWh in the second year. The maximum anticipated volume in each of the third and fourth years is 1.8 TWh. The maximum length of the program is four years, which expires April 30, 2006.

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. The provision for the TRO contracts was established based on meeting decontrol targets within three years of market opening. An additional charge of \$30 million related to the fourth year of the TRO contracts was recorded in 2003, based on OPG’s expectation that the Company would not meet the decontrol targets necessary for TRO contracts to expire after three years.

The change in the TRO contracts provision for the six months ended June 30, 2005 and year ended December 31, 2004 is as follows:

<i>(millions of dollars)</i>	<b>June 30 2005</b>	<b>December 31 2004</b>
Provision, beginning of period	<b>48</b>	100
Decrease of provision during the period	<b>(18)</b>	(52)
Provision, end of period	<b>30</b>	48

## 13. MARKET POWER MITIGATION AGREEMENT REBATE

Until April 1, 2005, OPG was 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 included both a rebate mechanism and the requirement to decontrol generating capacity. Under the rebate mechanism, a majority of OPG’s expected energy sales in Ontario were subject to an average annual revenue cap of 3.8¢/kWh. During the term of the Market Power Mitigation Agreement, OPG was required to pay a rebate to the Independent Electricity System Operator equal to the excess, if any, of the average hourly spot energy price over 3.8¢/kWh for a 12-month settlement period, multiplied by the amount of energy subject to the rebate mechanism. The Market Power Mitigation Agreement was replaced effective April 1, 2005 by a regulated price for baseload hydroelectric and nuclear generation and a revenue limit that applies to OPG’s unregulated generation assets.

In accordance with the Market Power Mitigation Agreement, the rebate is calculated after taking into account the amount of energy sales subject to the rebate mechanism for only those generating stations that OPG continues to control. Since the average hourly spot price during the three months ended March 31, 2005, when the rebate mechanism ended, exceeded the 3.8¢/kWh revenue cap, OPG provided \$412 million (three months ended March 31, 2004 – \$441 million) as a Market Power Mitigation Agreement rebate. During the six months ended June 30, 2004, OPG provided \$649 million as a Market Power Mitigation Agreement rebate.

The change in the Market Power Mitigation Agreement rebate liability for the six months ended June 30, 2005 and year ended December 31, 2004 is as follows:

<i>(millions of dollars)</i>	<b>June 30 2005</b>	<b>December 31 2004</b>
Liability, beginning of period	439	409
Increase to provision during the period	412	1,154
Payments	<b>(606)</b>	(1,124)
Liability, end of period	<b>245</b>	439

#### **14. REVENUE LIMIT REBATE**

A regulation made pursuant to the *Electricity Restructuring Act, 2004* requires that 85 per cent of the generation output from OPG's unregulated generation assets, excluding the Lennox generating station, TRO volumes and forward sales as of January 1, 2005, are subject to a revenue limit based on an average price of \$47.00/MWh (4.7¢/kWh). This revenue limit is in place for a period of 13 months ending April 30, 2006. Revenues above this limit will be rebated at the end of the period.

The change in the revenue limit rebate liability for the six months ended June 30, 2005 is as follows:

<i>(millions of dollars)</i>	<b>June 30 2005</b>
Liability, beginning of period	-
Increase to provision during the year	141
Payments	-
Liability, end of period	141

#### **15. BUSINESS SEGMENTS**

A regulation made pursuant to the *Electricity Restructuring Act, 2004* provided that OPG would receive regulated prices for its baseload hydroelectric and nuclear facilities. These initial prices took effect April 1, 2005, and are expected to remain in effect until at least March 31, 2008, at which time it is anticipated that the Ontario Energy Board ("OEB") will have established new regulated prices. Given the effective date of these prices, and the OPG's management approach, OPG changed its definition of business segments on April 1, 2005 from Generation and Energy Marketing to Regulated – Nuclear, Regulated – Hydroelectric and Unregulated Generation. OPG will continue to report other activities, including the previously separately presented trading activities in the Other category. As a result of this change in definition, OPG has reclassified the comparative periods to be consistent with the current presentation of business segments.

<b>Segment Income for three months ended June 30, 2005</b>	<b>Regulated – Nuclear</b>	<b>Regulated – Hydroelectric</b>	<b>Unregulated Generation</b>	<b>Other</b>	<b>Total</b>
<i>(millions of dollars)</i>					
Revenues					
Revenue	540	202	744	28	1,514
Market Power Mitigation Agreement rebate	-	-	-	-	-
Revenue limit rebate	-	-	(141)	-	(141)
	540	202	603	28	1,373
Fuel expense	25	69	195	-	289
Gross margin	515	133	408	28	1,084
Operations, maintenance and administration	441	18	142	15	616
Depreciation and amortization	94	16	74	8	192
Accretion on fixed asset removal and nuclear waste management liabilities	117	-	3	-	120
Earnings on nuclear fixed asset removal and nuclear waste management funds	(112)	-	-	-	(112)
Property and capital taxes	11	5	8	(7)	17
Operating (loss) income	(36)	94	181	12	251
Impairment of long-lived assets	63	-	-	-	63
(Loss) income before interest, income taxes and extraordinary item	(99)	94	181	12	188

<b>Segment Income for three months ended June 30, 2004</b>	<b>Regulated – Nuclear</b>	<b>Regulated – Hydroelectric</b>	<b>Unregulated Generation</b>	<b>Other</b>	<b>Total</b>
<i>(millions of dollars)</i>					
Revenues					
Revenue	545	244	544	16	1,349
Market Power Mitigation Agreement rebate	(64)	(37)	(107)	-	(208)
	481	207	437	16	1,141
Fuel expense	24	64	154	-	242
Gross margin	457	143	283	16	899
Operations, maintenance and administration excluding Pickering A return to service	397	18	140	13	568
Pickering A return to service	65	-	-	-	65
Depreciation and amortization	93	18	76	7	194
Accretion on fixed asset removal and nuclear waste management liabilities	112	-	2	-	114
Earnings on nuclear fixed asset removal and nuclear waste management funds	(80)	-	-	-	(80)
Property and capital taxes	4	6	13	7	30
Restructuring	-	-	16	-	16
(Loss) income before interest, income taxes and extraordinary item	(134)	101	36	(11)	(8)

<b>Segment Income for six months ended June 30, 2005</b>	<b>Regulated – Nuclear</b>	<b>Regulated – Hydroelectric</b>	<b>Unregulated Generation</b>	<b>Other</b>	<b>Total</b>
<i>(millions of dollars)</i>					
Revenues					
Revenue	1,280	472	1,485	47	3,284
Market Power Mitigation Agreement rebate	(160)	(65)	(187)	-	(412)
Revenue limit rebate	-	-	(141)	-	(141)
	1,120	407	1,157	47	2,731
Fuel expense	54	122	423	-	599
Gross margin	1,066	285	734	47	2,132
Operations, maintenance and administration	859	36	279	29	1,203
Depreciation and amortization	186	34	148	17	385
Accretion on fixed asset removal and nuclear waste management liabilities	234	-	5	-	239
Earnings on nuclear fixed asset removal and nuclear waste management funds	(183)	-	-	-	(183)
Property and capital taxes	22	9	16	(9)	38
Operating (loss) income	(52)	206	286	10	450
Impairment of long-lived assets	63	-	202	-	265
(Loss) income before interest, income taxes and extraordinary item	(115)	206	84	10	185

<b>Segment Income for six months ended June 30, 2004</b>	<b>Regulated – Nuclear</b>	<b>Regulated – Hydroelectric</b>	<b>Unregulated Generation</b>	<b>Other</b>	<b>Total</b>
<i>(millions of dollars)</i>					
Revenues					
Revenue	1,197	527	1,377	39	3,140
Market Power Mitigation Agreement rebate	(206)	(106)	(337)	-	(649)
Revenue limit rebate	-	-	-	-	-
	991	421	1,040	39	2,491
Fuel expense	54	115	411	-	580
Gross margin	937	306	629	39	1,911
Operations, maintenance and administration excluding Pickering A return to service	796	35	277	25	1,133
Pickering A return to service	124	-	-	-	124
Depreciation and amortization	186	33	154	13	386
Accretion on fixed asset removal and nuclear waste management liabilities	223	-	4	-	227
Earnings on nuclear fixed asset removal and nuclear waste management funds	(178)	-	-	-	(178)
Property and capital taxes	12	11	23	12	58
Restructuring	-	-	16	-	16
(Loss) income before interest, income taxes and extraordinary item	(226)	227	155	(11)	145

<b>Selected Balance Sheet Information</b> <i>(millions of dollars)</i>	<b>Regulated – Nuclear</b>	<b>Regulated – Hydroelectric</b>	<b>Unregulated Generation</b>	<b>Other</b>	<b>Total</b>
June 30, 2005					
Segment property, plant and equipment, net	3,228	4,018	3,675	611	11,532
December 31, 2004					
Segment property, plant and equipment, net	3,305	4,016	3,985	634	11,940
<b>Selected Cash Flow Information</b> <i>(millions of dollars)</i>					
Three months ended June 30, 2005					
Capital expenditures	66	21	19	-	106
Three months ended June 30, 2004					
Capital expenditures	76	6	16	29	127
Six months ended June 30, 2005					
Capital expenditures	160	37	36	7	240
Six months ended June 30, 2004					
Capital expenditures	132	12	29	50	223

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

<i>(millions of dollars)</i>	<b>Three Months Ended June 30</b>		<b>Six Months Ended June 30</b>	
	<b>2005</b>	<b>2004</b>	<b>2005</b>	<b>2004</b>
Accounts receivable	38	16	(51)	36
Income taxes recoverable	-	4	-	16
Fuel inventory	(26)	(127)	73	(11)
Materials and supplies	(12)	(1)	(26)	(17)
Market Power Mitigation Agreement rebate payable	(386)	(130)	(194)	(3)
Revenue limit rebate payable	141	-	141	-
Accounts payable and accrued charges	58	22	(105)	(160)
Income and capital taxes payable	3	7	11	7
	<b>(184)</b>	<b>(209)</b>	<b>(151)</b>	<b>(132)</b>

The amount of cash income taxes paid in the three and six months ended June 30, 2005 was \$5 million and \$9 million (three and six months ended June 30, 2004 – \$2 million and \$5 million).

#### 17. SEASONAL OPERATIONS

OPG's quarterly results are impacted by changes in demand resulting from variations in seasonal weather conditions. Historically, OPG's revenues are higher in the first and third quarters of a fiscal year as a result of winter heating demands in the first quarter and air conditioning/cooling demands in the third quarter. The Market Power Mitigation Agreement rebate and OPG's hedging strategies significantly reduced the impact of seasonal price fluctuations on the results of operations. Commencing April 1, 2005, regulated prices for the baseload hydroelectric and nuclear facilities and the revenue limit related to the generation from OPG's other generating assets will further reduce the impact of seasonal price fluctuations on operating results.