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ONTARIO POWER GENERATION REPORTS 2011 THIRD QUARTER FINANCIAL RESULTS

[Toronto]: Ontario Power Generation Inc. ("OPG" or the "Company") today reported its financial and operating results for the three and nine months ended September 30, 2011. Net loss for the third quarter of 2011 was $96 million compared to net income of $333 million for the same period in 2010. Net income for the nine months ended September 30, 2011 was $169 million compared to $447 million for the same period in 2010.

Tom Mitchell, President and Chief Executive Officer, said, "The decline in our net income during the first nine months of 2011 should not overshadow the fact that OPG had very good production performance from our generating stations."

"Over the first nine months of 2011, our nuclear units and our hydroelectric units increased their output by about 10 percent over production in the first nine months of last year. The higher production during the period was achieved with reduced OM&A expenses and without any increase in electricity prices."

"Unfortunately our bottom line was hit by the global decline in markets over the past few months, which negatively impacted the value of the funds set aside to pay for the decommissioning of nuclear plants and nuclear waste management."

The decrease in earnings of $429 million during the third quarter of 2011 compared to the same period in 2010 was primarily a result of a decline in the valuation levels in the global financial markets, which resulted in losses from the nuclear fixed asset removal and nuclear waste management funds ("Nuclear Funds"). The Nuclear Funds are designed to achieve the required return over a long-term horizon. While short-term fluctuations in market value will occur, managing the long-term return of these funds continues to be the primary goal. The net income impact related to the losses in the Nuclear Funds was partially mitigated by lower operations, maintenance and administration ("OM&A") expenses.

For the nine months ended September 30, 2011, net income decreased by $278 million compared to the same period in 2010, primarily as a result of lower earnings from the Nuclear Funds, the impact of lower Ontario spot electricity market prices on the Unregulated – Hydroelectric business segment, and certain other decreases in revenue. These reductions in net income were partially offset by higher nuclear and hydroelectric electricity production, and lower OM&A expenses. In addition, there was an increase in income tax expense for the nine months ended September 30, 2011 compared to the same period in 2010 due to higher income before earnings from the Nuclear Funds.

Generating and Operating Performance

Total electricity generated during the three months ended September 30, 2011 was 21.4 terawatt hours ("TWh") compared to 22.7 TWh for the same period in 2010. Total electricity generation for the nine months ended September 30, 2011 was 64.3 TWh compared to 66.9 TWh for the same period in 2010. The decrease in generation was primarily due to lower thermal generation, partially offset by an increase in nuclear and hydroelectric generation.

The capability factors for the Darlington nuclear station for the three and nine month periods ended September 30, 2011 increased compared to the same periods in 2010 due to a decrease in the number of both planned and unplanned outage days.

The capability factor at the Pickering A nuclear station increased during the third quarter of 2011 compared to the same quarter in 2010 largely due to the timing of planned outages. The lower capability factor at the Pickering B nuclear station during the third quarter of 2011 was primarily the result of an extension to a planned outage.

The higher capability factors at the Pickering A and B nuclear generating stations during the nine months ended September 30, 2011 primarily reflected a decrease in planned outage days compared to the same period in 2010 when all six units were shutdown during the Vacuum Building Outage in the second quarter of 2010.

The high availability factors for OPG's regulated and unregulated hydroelectric stations continued during the three and nine months ended September 30, 2011.

Equivalent forced outage rates ("EFOR") at the thermal stations were higher for the three and nine months ended September 30, 2011 compared to the same periods in 2010 primarily due to a higher number of unplanned outage days at the Nanticoke and Lambton stations. The higher number of unplanned outage days is consistent with the implementation of a management strategy, which entails carefully managing outage expenditures while ensuring the units are available as required during a period of reduced production.

The 2011 EFOR reflects management's strategy to ensure that units are available when required while optimizing outage duration and scope, and the cost to return units to service. Consistent with Ontario's Long-Term Energy Plan, OPG placed two units at the Nanticoke coal-fired station on standby on October 1, 2011. The units will be placed in safe shutdown mode on December 31, 2011.

Generation Development

OPG is undertaking a number of generation development projects aimed at significantly contributing to Ontario's long-term electricity supply requirements. The status of these capacity expansion or life extension projects is as follows:

Nuclear

- In August 2011, the Joint Review Panel ("JRP") overseeing the Environmental Assessment ("EA") of the Darlington New Nuclear Project submitted its report to the federal Minister of the Environment. The JRP concluded that the project is not likely to cause significant adverse environmental impacts. The federal government will now prepare its response for approval by the Governor in Council, with a final determination of whether or not the EA should be accepted.

- The EA for the Darlington Refurbishment Project is on track for submission to the Canadian Nuclear Safety Commission ("CNSC") in late 2011. A third party report on the Integrated Safety Review ("ISR") was provided to OPG in the third quarter of 2011 and its recommendations were addressed. The stakeholder review of the final ISR was completed and the final report was submitted to the CNSC.

- OPG is undertaking a coordinated set of initiatives to evaluate the opportunity to continue safe and reliable operations of Pickering B for an additional four to six years beyond the station's nominal end of life. In the third quarter of 2011, OPG began execution of the second of several major planned outages on Unit 6 targeted at improving the reliability of the generating station and collecting necessary inspection results to support continued operation.

Hydroelectric

- The tunnel boring machine mining activity has been completed, and the disassembly of the tunnel boring machine is in progress. Lining installation activities at the Niagara Tunnel continue. Installation of the lower one-third of the permanent concrete lining had reached 7,625 metres by July 2, 2011 when this work was temporarily interrupted to do reinforcement repair work in the 6,050 metre area of the tunnel. This lining work is expected to resume in January 2012. All other tunnel lining activities are continuing. As at September 30, 2011, the life-to-date capital expenditures were $1.1 billion. The project is expected to be completed within the approved budget of $1.6 billion and the approved project completion date of December 2013.

- The Lower Mattagami River project will increase the capacity of the four generating stations on the Lower Mattagami River by 438 MW. During the third quarter of 2011, additional rock consolidation work was undertaken at the Smoky Falls site to remediate unanticipated geological conditions while concrete operations continued. At the Little Long site, concrete operations commenced and the draft tube formwork was installed. The cofferdam installation commenced at the Kipling site and the Harmon site cofferdam installation was completed. As at September 30, 2011, the life-to-date capital expenditures were $619 million. The project is expected to be completed within the approved budget of $2.6 billion and the approved completion date of June 2015.

Thermal

- Conversion of the Atikokan generating station to biomass is currently in the definition phase. OPG and the Ontario Power Authority ("OPA") are continuing to negotiate an energy supply agreement.

- On August 17, 2011, the Minister of Energy issued a directive to the OPA to negotiate a long-term energy supply contract with OPG for the conversion of two coal-fired units at the Thunder Bay generating station to natural gas. OPG began discussions with the OPA in October 2011.

- As outlined in Ontario's Long-Term Energy Plan and Supply Mix Directive to the OPA, OPG continues to explore the possible conversion of some units at the Lambton and Nanticoke generating stations to natural gas, if required for system reliability.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	Three Months Ended September 30		Nine Months Ended September 30	
	2011	**2010**	**2011**	**2010**
Earnings				
Revenue	**1,275**	1,391	**3,809**	4,044
Fuel expense	**217**	259	**566**	716
Gross margin	**1,058**	1,132	**3,243**	3,328
Operations, maintenance and administration	**628**	677	**2,026**	2,185
Depreciation and amortization	**197**	175	**550**	515
Accretion on fixed asset removal and nuclear waste management liabilities	**177**	165	**526**	495
Losses (earnings) on nuclear fixed asset removal and nuclear waste management funds	**16**	(287)	**(286)**	(468)
Restructuring	**19**	-	**19**	25
Property and capital taxes	**15**	20	**38**	63
Other (gains) losses	**(2)**	1	**(5)**	(1)
Income before interest and income taxes	**8**	381	**375**	514
Net interest expense	**39**	41	**121**	130
Income tax expense (recovery)	**65**	7	**85**	(63)
Net (loss) income	**(96)**	333	**169**	447
Income (loss) before interest and income taxes				
Generating segments	**161**	240	**536**	484
Nuclear Waste Management segment	**(192)**	122	**(240)**	(27)
Other segment	**39**	19	**79**	57
Total income before interest and income taxes	**8**	381	**375**	514
Cash flow				
Cash flow provided by operating activities	**431**	359	**993**	687
Electricity Generation (TWh)				
Regulated – Nuclear	**12.6**	11.8	**36.6**	33.4
Regulated – Hydroelectric	**4.9**	4.8	**14.5**	14.2
Unregulated – Hydroelectric	**2.0**	1.9	**10.1**	8.1
Unregulated – Thermal	**1.9**	4.2	**3.1**	11.2
Total electricity generation	**21.4**	22.7	**64.3**	66.9
Average electricity sales price (¢/kWh)				
Regulated – Nuclear	**5.6**	5.5	**5.5**	5.5
Regulated – Hydroelectric	**3.5**	3.8	**3.5**	3.7
Unregulated – Hydroelectric	**3.7**	4.5	**3.3**	3.9
Unregulated – Thermal	**3.9**	5.4	**3.5**	4.5
OPG average sales price [1]	**5.1**	5.2	**5.1**	5.1
Nuclear unit capability factor (percent)				
Darlington	**97.5**	86.3	**93.9**	87.4
Pickering A	**79.3**	65.9	**73.9**	54.5
Pickering B	**77.5**	86.9	**77.3**	75.3
Availability (percent)				
Regulated – Hydroelectric	**93.4**	93.0	**91.0**	92.8
Unregulated– Hydroelectric	**87.5**	87.5	**91.9**	91.6
Equivalent forced outage rate (percent)				
Unregulated – Thermal	**13.1**	10.7	**9.5**	7.0

[1] Includes other energy revenues primarily from cost recovery agreements for the Nanticoke, Lambton, and Lennox generating stations.

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our focus is on the efficient production and sale of electricity from our generation assets, while operating in a safe, open and environmentally responsible manner.

Ontario Power Generation Inc.'s unaudited consolidated financial statements and Management's Discussion and Analysis as at and for the three and nine months ended September 30, 2011, can be accessed on OPG's Web site (www.opg.com), the Canadian Securities Administrators' Web site (www.sedar.com), or can be requested from the Company.

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ONTARIOPOWER GENERATION

2011 THIRD QUARTER REPORT

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MANAGEMENT'S DISCUSSION AND ANALYSIS

UNAUDITED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. ("OPG" or the "Company") as at and for the three and nine month periods ended September 30, 2011. For a complete description of OPG's corporate strategies, risk management, corporate governance, related parties transactions and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, and the MD&A as at and for the year ended December 31, 2010. Certain of the 2010 comparative amounts have been reclassified to conform to the 2011 presentation. OPG's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and are presented in Canadian dollars. This MD&A is dated November 16, 2011.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could" and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks and uncertainties, including those set out under the heading *Risk Management,* and therefore, could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's fuel costs and availability, asset performance, nuclear decommissioning and waste management, closure or conversion of coal-fired generating stations, refurbishment of existing facilities, development and construction of new facilities, pension and other post employment benefit ("OPEB") obligations, income taxes, spot electricity market prices, the on-going evolution of the Ontario electricity industry, proposed new legislation, conversion to International Financial Reporting Standards ("IFRS"), environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, and the impact of regulatory decisions by the Ontario Energy Board ("OEB"). Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG's focus is on the efficient generation and sale of electricity from its generating assets, while operating in a safe, open and environmentally responsible manner. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario.

As at September 30, 2011, OPG's electricity generating portfolio had an in-service capacity of 19,791 megawatts ("MW"), representing 57 percent of Ontario's installed electricity generating capacity. OPG operates three nuclear generating stations, five thermal generating stations, 65 hydroelectric generating stations, and two wind power turbines. In addition, OPG and TransCanada Energy Ltd. co-own the Portlands Energy Centre ("PEC") gas-fired combined cycle generating station. OPG and ATCO Power Canada Ltd. co-own the Brighton Beach gas-fired combined cycle generating station. OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P. ("Bruce Power"). These co-owned facilities and leased stations are incorporated into OPG's financial results, but are not included in the generation portfolio statistics set out in this report. A description of OPG's segments is provided in OPG's 2010 annual MD&A under the heading, *Business Segments*.

The in-service generating capacity by business segment as of September 30, 2011 is as follows:

(MW)	**September 30, 2011**
Regulated – Nuclear Generation	**6,606**
Regulated – Hydroelectric	**3,312**
Unregulated – Hydroelectric	**3,684**
Unregulated – Thermal	**6,187**
Other	**2**
Total	**19,791**

Effective October 1, 2011, OPG placed two coal-fired units at the Nanticoke generating station on stand-by. Details on the units and the associated restructuring costs are discussed under the heading, *Vision, Core Business and Strategy*.

REVENUE MECHANISMS FOR REGULATED AND UNREGULATED GENERATION

OPG receives regulated prices for electricity generated from the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and Pickering A and B and Darlington nuclear facilities (collectively the "Prescribed Facilities"). In March 2011, the OEB issued its decision on OPG's application for new regulated prices. Following its decision, in its April 2011 order, the OEB established a new regulated price for production from OPG's regulated hydroelectric facilities at $34.13/MWh, and a new regulated price for production from OPG's nuclear facilities at $55.85/MWh, effective March 1, 2011. The new regulated prices include rate riders reflecting the OEB's approval for recovery or repayment of variance and deferral account balances as at December 31, 2010. The regulated hydroelectric price is net of a negative rate rider of -$1.65/MWh. The nuclear regulated price includes a rate rider of $4.33/MWh. The rate riders will remain in effect until December 31, 2012.

The following reflects the new regulated prices effective March 1, 2011 compared to those in effect prior to March 1, 2011:

($/MWh)	**Effective March 1, 2011**	**Prior to March 1, 2011[1]**
Nuclear without rate rider	**51.52**	52.98
Nuclear rate rider	**4.33**	2.00
Nuclear regulated price	**55.85**	54.98
Hydroelectric without rate rider	**35.78**	36.66
Hydroelectric rate rider	**(1.65)**	-
Hydroelectric regulated price	**34.13**	36.66

[1] Regulated prices were effective for the period April 1, 2008 to February 28, 2011.

Electricity generated from OPG's other generating assets remains unregulated and continues to receive the Ontario electricity spot market price, except where an energy supply or cost recovery agreement is in place.

HIGHLIGHTS

Overview of Results

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

(millions of dollars – except where noted)	**Three Months Ended September 30 2011**	**Three Months Ended September 30 2010**	**Nine Months Ended September 30 2011**	**Nine Months Ended September 30 2010**
Revenue	**1,275**	1,391	**3,809**	4,044
Fuel expense	**217**	259	**566**	716
Gross margin	**1,058**	1,132	**3,243**	3,328
Expenses				
Operations, maintenance and administration	**628**	677	**2,026**	2,185
Depreciation and amortization	**197**	175	**550**	515
Accretion on fixed asset removal and nuclear waste management liabilities	**177**	165	**526**	495
Losses (Earnings) on nuclear fixed asset removal and nuclear waste management funds	**16**	(287)	**(286)**	(468)
Restructuring	**19**	-	**19**	25
Property and capital taxes	**15**	20	**38**	63
Other (gains) losses	**(2)**	1	**(5)**	(1)
	1,050	751	**2,868**	2,814
Income before interest and income taxes	**8**	381	**375**	514
Net interest expense	**39**	41	**121**	130
Income tax expense (recovery)	**65**	7	**85**	(63)
Net (loss) income	**(96)**	333	**169**	447
Electricity production (TWh)	**21.4**	22.7	**64.3**	66.9
Cash flow				
Cash flow provided by operating activities	**431**	359	**993**	687

Net loss for the three months ended September 30, 2011 was $96 million compared to net income of $333 million for the three months ended September 30, 2010. Loss before income taxes for the three months ended September 30, 2011 was $31 million compared to income before income taxes of $340 million for the same period in 2010.

Net income for the nine months ended September 30, 2011 was $169 million compared to $447 million for the nine months ended September 30, 2010. Income before income taxes for the nine months ended September 30, 2011 was $254 million compared to $384 million for the same period in 2010.

Earnings before Income Taxes for the Three Months Ended September 30, 2011

The following is a summary of the factors impacting OPG's results before income taxes for the three months ended September 30, 2011 compared to the same period in 2010, on a before-tax basis:

(millions of dollars)	Electricity Generation Segments[1]	Regulated Nuclear Waste Management Segment	Other[2]	Total
Income (loss) before income taxes for the three months ended September 30, 2010	**240**	**122**	**(22)**	**340**
Changes in gross margin:				
Change in electricity sales price:				
Regulated generation segments	(4)	-	-	(4)
Unregulated – Hydroelectric	(18)	-	-	(18)
Change in electricity generation by segment:				
Regulated – Nuclear Generation	37	-	-	37
Regulated – Hydroelectric	7	-	-	7
Unregulated – Hydroelectric	1	-	-	1
Decrease in thermal generation revenue partially offset by a decrease in fuel costs primarily due to lower generation, and higher revenue related to the contingency support agreement for the Nanticoke and Lambton generating stations	(34)	-	-	(34)
Decrease in gross margin due to the cessation of additions to the Tax Loss Variance Account based on the OEB's March 2011 decision on new regulated prices	(48)	-	-	(48)
Increase (decrease) in non-electricity generation revenue, net of the impact of the regulatory variance account associated with stations on lease to Bruce Power	6	6	(12)	-
Other changes in gross margin	(20)	-	5	(15)
	(73)	6	(7)	(74)
Changes in operations, maintenance and administration ("OM&A") expenses:				
Lower expenditures related to a decrease in nuclear outage and project costs	39	-	-	39
Lower expenditures at OPG's thermal generating stations primarily due to the continuation of vacancy and overtime management programs and reduced scope of work associated with changing operating profiles	14	-	-	14
Reduction in expenditures related to new nuclear generation development and capacity refurbishment, net of the impact of related regulatory variance accounts	9	-	-	9
Increase in pension and OPEB costs largely as a result of lower discount rates in 2011, net of the impact of the regulatory variance account	(25)	-	-	(25)
Other changes in OM&A expenses	12	(5)	5	12
	49	(5)	5	49
Decrease in earnings from the Nuclear Funds	-	(596)	-	(596)
Impact of the regulatory variance account associated with stations on lease to Bruce Power on earnings from the Nuclear Funds	-	293	-	293
Increase in amortization expense due to the amortization of regulatory balances as a result of the OEB's decision effective March 1, 2011	(35)	-	-	(35)
Increase in restructuring costs related to coal-fired units	(19)	-	-	(19)
(Loss) gain recognized as a result of changes to the asset retirement obligation ("ARO") related to certain thermal generating stations	(18)	-	20	2
Other changes	17	(12)	4	9
Income (loss) before income taxes for the three months ended September 30, 2011	**161**	**(192)**	**-**	**(31)**

[1] Electricity generation segments include results of the Regulated – Nuclear Generation, Regulated – Hydroelectric, Unregulated – Hydroelectric, and Unregulated – Thermal segments.

[2] Other includes results of the Other category in OPG's segmented statement of income, inter-segment eliminations, and net interest expense.

Earnings before Income Taxes for the Nine Months Ended September 30, 2011

The following is a summary of the factors impacting OPG's results before income taxes for the nine months ended September 30, 2011 compared the same period in 2010, on a before-tax basis:

(millions of dollars)	**Electricity Generation Segments**[1]	**Regulated Nuclear Waste Management Segment**	**Other**[2]	**Total**
Income (loss) before income taxes for the nine months ended September 30, 2010	**484**	**(27)**	**(73)**	**384**
Changes in gross margin:				
Change in electricity sales price:				
Regulated generation segments	4	-	-	4
Unregulated – Hydroelectric	(72)	-	-	(72)
Change in electricity generation by segment:				
Regulated – Nuclear Generation	160	-	-	160
Regulated – Hydroelectric	8	-	-	8
Unregulated – Hydroelectric	69	-	-	69
Decrease in thermal generation revenue and higher fuel-related costs, partially offset by a decrease in fuel costs primarily due to lower generation, and higher revenue related to the contingency support agreement for the Nanticoke and Lambton generating stations	(89)	-	-	(89)
Lower revenue recognized related to an energy supply contract for the Lennox generating station	(18)	-	-	(18)
Decrease in gross margin due to the cessation of additions to the Tax Loss Variance Account based on the OEB's March 2011 decision on new regulated prices	(112)	-	-	(112)
(Decrease) increase in non-electricity generation revenue, net of the impact of the regulatory variance account associated with stations on lease to Bruce Power	(19)	9	(10)	(20)
Other changes in gross margin	(14)	-	(1)	(15)
	(83)	9	(11)	(85)
Changes in OM&A expenses:				
Lower expenditures related to a decrease in nuclear outage and project costs, partially offset by an increase in maintenance activities at OPG's nuclear generating stations	142	-	-	142
Lower expenditures at OPG's thermal generating stations primarily due to the continuation of vacancy and overtime management programs and reduced scope of work associated with changing operating profiles	46	-	-	46
Reduction in expenditures related to new nuclear generation development and capacity refurbishment, net of the impact of related regulatory variance accounts	28	-	-	28
(Increase) decrease in pension and OPEB costs largely as a result of lower discount rates in 2011, net of the impact of the regulatory variance account	(88)	1	-	(87)
Other changes in OM&A expenses	37	(10)	3	30
	165	(9)	3	159
Decrease in earnings from the Nuclear Funds	-	(395)	-	(395)
Impact of the regulatory variance account associated with stations on lease to Bruce Power on earnings from the Nuclear Funds	-	213	-	213
Increase in depreciation and amortization expense, primarily due to the amortization of regulatory balances as a result of the OEB's decision effective March 1, 2011, partially offset by lower depreciation expense for OPG's thermal generating stations	(42)	-	7	(35)
Increase in accretion expense primarily due to an increase in the present value of the liabilities for nuclear fixed asset removal and nuclear waste management ("Nuclear Liabilities") due to the passage of time	-	(31)	-	(31)
Decrease in restructuring costs related to coal-fired units	6	-	-	6
(Loss) gain recognized as a result of changes to the ARO related to certain thermal generating stations	(18)	-	20	2
Other changes	24	-	12	36
Income (loss) before income taxes for the nine months ended September 30, 2011	**536**	**(240)**	**(42)**	**254**

[1] Electricity generation segments include results of the Regulated – Nuclear Generation, Regulated – Hydroelectric, Unregulated – Hydroelectric, and Unregulated – Thermal segments.
[2] Other includes results of the Other category in OPG's segmented statement of income, inter-segment eliminations, and net interest expense.

Income Tax Expense

For the three months ended September 30, 2011, income tax expense was $65 million compared to $7 million for the same period in 2010. The increase in income tax expense was primarily due to the additions recorded in the Bruce Lease Net Revenues Variance Account related to taxes in the third quarter of 2011.

For the nine months ended September 30, 2011, income tax expense was $85 million compared to income tax recovery of $63 million for the same period in 2010. The increase in income tax expense was largely due to higher income before earnings from the Decommissioning Segregated Fund ("Decommissioning Fund") and the Used Fuel Segregated Fund ("Used Fuel Fund") (together "Nuclear Funds") in 2011. Earnings in the Nuclear Funds are not taxable until withdrawn. In addition, during the nine months ended September 2010, OPG resolved a number of tax uncertainties related to prior taxation years, which resulted in a reduction to the income tax liabilities and a decrease in income tax expense.

Electricity Generation

OPG's electricity generation for the three and nine month periods ended September 30, 2011 and 2010, was as follows:

	Three Months Ended September 30		**Nine Months Ended September 30**	
(TWh)	**2011**	**2010**	**2011**	**2010**
Regulated – Nuclear Generation	**12.6**	11.8	**36.6**	33.4
Regulated – Hydroelectric	**4.9**	4.8	**14.5**	14.2
Unregulated – Hydroelectric	**2.0**	1.9	**10.1**	8.1
Unregulated – Thermal	**1.9**	4.2	**3.1**	11.2
Total electricity generation	**21.4**	22.7	**64.3**	66.9

Total electricity generation during the three months ended September 30, 2011 was 21.4 TWh compared to 22.7 TWh for the same period in 2010. The decrease in electricity generation was largely due to a decrease in thermal generation, partially offset by higher nuclear and hydroelectric generation. The decrease in thermal generation of 2.3 TWh during the third quarter of 2011 compared to the third quarter of 2010 was primarily due to an increase in baseload generation from nuclear and hydroelectric generating stations. During the third quarter of 2011, electricity generation from the Regulated – Nuclear Generation segment increased by 0.8 TWh compared to the third quarter of 2010. The increase was primarily due to lower unplanned and planned outage days at the Darlington generating station, and lower planned outage days at the Pickering A generating station.

Ontario primary electricity demand for the three months ended September 30, 2011 was 37.0 TWh compared to 37.3 TWh for the same period in 2010. The decrease in demand was primarily due to a weaker economy, partially offset by warmer weather conditions during the third quarter of 2011 compared to the same quarter in 2010.

Total electricity generation during the nine months ended September 30, 2011 was 64.3 TWh compared to 66.9 TWh for the same period in 2010. The decrease in electricity generation was largely due to lower thermal generation, partially offset by higher nuclear and hydroelectric generation. Electricity generation from the Unregulated – Thermal segment decreased by 8.1 TWh during the nine months ended September 30, 2011 compared to the same period in 2010. The decrease was primarily due to higher electricity generation from other generators in Ontario and increased generation from OPG's nuclear and hydroelectric generating stations. The increase in electricity generation from other generators in Ontario was primarily due to lower natural gas prices relative to coal prices. Electricity generation from the Regulated – Nuclear Generation segment increased by 3.2 TWh during the nine months ended September 30, 2011 compared to the same period in 2010. The higher nuclear generation was primarily due to a decrease in planned outage days at the Pickering and Darlington generating stations. The decrease in outage days at the Pickering generating stations was primarily a result of the Pickering

Vacuum Building outage in the second quarter of 2010. The increase in nuclear generation was partially offset by the impact of higher unplanned outage days at the Pickering A nuclear generating station for the nine months ended September 30, 2011 compared to the same period in 2010.

Electricity generation from the Unregulated – Hydroelectric segment increased by 2.0 TWh during the nine months ended September 30, 2011 compared to same period in 2010. The increase was primarily due to higher water flows compared to the same period in 2010.

Ontario primary electricity demand for the nine months ended September 30, 2011 and 2010 was 107.2 TWh.

Average Sales Prices

The weighted average Ontario spot electricity market price and OPG's average sales prices, by reportable electricity segment for the three and nine month periods ended September 30, 2011 and 2010, were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(¢/kWh)	**2011**	**2010**	**2011**	**2010**
Weighted average hourly Ontario spot electricity market price	**3.5**	4.5	**3.2**	4.0
Regulated – Nuclear Generation	**5.6**	5.5	**5.5**	5.5
Regulated – Hydroelectric	**3.5**	3.8	**3.5**	3.7
Unregulated – Hydroelectric	**3.7**	4.5	**3.3**	3.9
Unregulated – Thermal	**3.9**	5.4	**3.5**	4.5
OPG's average sales price [1]	**5.1**	5.2	**5.1**	5.1

[1] Includes other energy revenues primarily from cost recovery agreements for the Nanticoke, Lambton, and Lennox generating stations. Had the cost recovery agreements for Nanticoke, Lambton, and Lennox generating stations been excluded, OPG's average sales price would have been 4.8¢/kWh and 4.6¢/kWh for the three and nine month periods ended September 30, 2011, and 5.0¢/kWh and 4.7¢/kWh, respectively, during the same periods in 2010.

The changes in average sales prices for the regulated segments for the three and nine month periods ended September 30, 2011 reflect the OEB's March 2011 decision establishing new regulated prices effective March 1, 2011, as discussed under the heading, *Revenue Mechanisms for Regulated and Unregulated Generation*.

The decrease in average sales prices for the Unregulated – Hydroelectric and the Unregulated – Thermal segments for the three and nine month periods ended September 30, 2011 compared to the same periods in 2010 was primarily due to the impact of lower average hourly Ontario spot electricity market prices. The decrease in the average hourly Ontario spot electricity market price for the three and nine month periods ended September 30, 2011 compared to the same periods in 2010 was primarily due to higher nuclear and hydroelectric baseload generation in Ontario, and lower natural gas prices.

Cash Flow from Operations

Cash flow provided by operating activities for the three months ended September 30, 2011 was $431 million compared to $359 million for the three months ended September 30, 2010. The increase in cash flow was primarily due to lower OM&A expenditures and lower fuel purchases. This increase was partially offset by lower cash receipts as a result of lower generation revenue in the third quarter of 2011 compared to the same period in 2010.

Cash flow provided by operating activities for the nine months ended September 30, 2011 was $993 million compared to $687 million for the same period in 2010. The increase in cash flow was primarily due to lower OM&A expenditures, lower fuel purchases, and lower tax instalments, compared to the same period in 2010. The increase in operating cash flows for the nine months ended September 30, 2011 compared to the same period in 2010 was partially offset by lower cash receipts as a result of lower generation revenue.

VISION, CORE BUSINESS AND STRATEGY

OPG's mandate is to reliably and cost-effectively produce electricity from its diversified portfolio of generating assets, while operating in a safe, open, and environmentally responsible manner. OPG's vision is to be a leader in clean energy generation and to have a major role in leading Ontario's transition to a more sustainable energy future. OPG is focused on three corporate strategies: performance excellence; generation development; and developing and acquiring talent.

Performance Excellence

This section provides an update to OPG's performance excellence disclosure and should be read in conjunction with OPG's 2010 annual MD&A. A detailed discussion of OPG's commitment to performance excellence in the areas of generation, safety, the environment, and fiscal performance is included in the 2010 annual MD&A under the heading, *Performance Excellence*.

Nuclear

<u>Nuclear Generating Assets</u>

OPG has commenced the operational amalgamation of the Pickering A and B generating stations. The stations share many safety and operational systems. In the third quarter of 2011, organizational decisions were made to combine the two stations at the senior plant management level. For the balance of 2011, reporting will continue on a separate station basis. OPG continues the integration of the operations and reporting of the two stations and plans to report the stations as a six unit integrated site in 2012.

As part of the continuous improvement efforts to increase safety margins for its nuclear stations, OPG began the process of acquiring items such as portable standby electrical supplies and has made improvements to emergency response procedures.

<u>Deep Geologic Repository for Low and Intermediate Level Waste</u>

In 2010, OPG approved the commencement of the detailed design phase of the Deep Geologic Repository ("DGR") project for the long-term management of low and intermediate level waste from OPG-owned nuclear generating stations. The Environmental Impact Statement ("EIS") was submitted to the CNSC in April 2011. The next step of the environmental assessment is the selection of the Joint Review Panel.

Hydroelectric Generating Assets

OPG plans to increase the capacity of certain existing stations by a total of 34 MW over the next five years, through the replacement of existing turbine runners, generators, transformers, and other control components, with more efficient equipment. OPG is also planning to repair, rehabilitate, or replace aging civil structures.

In the third quarter of 2011, OPG completed major equipment overhauls and rehabilitation work at several stations. This included the protection and control upgrades of Units 5 to 8 at the R.H. Saunders generating station.

Thermal Generating Assets

Consistent with Ontario's Long-Term Energy Plan (the "Energy Plan") released in November 2010 and the Supply Mix Directive issued to the Ontario Power Authority ("OPA") in February 2011, OPG has placed two coal-fired generating units at the Nanticoke generating station on stand-by effective October 1, 2011. The units will be placed in safe shutdown mode on December 31, 2011. The early closure of these coal-fired units, in advance of the December 31, 2014 target deadline, will result in lower OM&A expense over the next three years. During 2011, OPG managed the change in the workforce associated with the planned safe shutdown of the two units through the provisions of existing collective agreements and on-going involvement and discussions with union representatives.

During the three and nine month periods ended September 30, 2011, OPG recognized $19 million of restructuring charges due to severance costs related to the safe shutdown of the two coal-fired units. Additional restructuring costs associated with the unit closure are estimated to be $3 million and are expected to be recorded in 2012. Additional costs of approximately $10 million are expected to be incurred in 2012 as a result of changes to equipment and power systems at the Nanticoke coal-fired station necessitated by the safe shutdown of the two additional units.

Environmental Performance

On August 27, 2011, Environment Canada issued its proposed greenhouse gas ("GHG") emissions regulation for a 60-day comment period. The *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* will restrict CO_2 emissions from coal-fired stations based on the unit's age, starting in July 2015. Coal-fired units will be permitted to operate up until 45 years from their commissioning date. After 45 years, units must meet a CO_2 emission intensity limit of 375 Mg CO_2/GWh, which is expected to prevent continued coal-fired operation without significant modifications such as carbon capture and storage or very high rates of biomass co-firing. The regulation will not apply to coal units converted to biomass or natural gas. Since OPG will no longer use coal to produce electricity after 2014, the regulation is not expected to affect OPG, including units to be converted to biomass or natural gas.

For the nine months ended September 30, 2011, CO_2 emissions from coal-fired stations were 3.4 million tonnes compared to 11.3 million tonnes for the same period in 2010. Acid gas emissions from coal-fired stations were 13.9 gigagrams and 49.2 gigagrams for the nine months ended September 30, 2011 and 2010, respectively. Emissions were significantly reduced during the nine months ended September 30, 2011 compared to the same period in 2010 as a result of lower generation from OPG's coal-fired generating stations.

Safety

OPG is committed to achieve its goal of zero injuries through further development of a strong safety culture and continuous improvement in safety management systems and risk control programs. To address two health and safety risk areas, OPG's 2011 objectives include a focus on falling object prevention and in the application of work protection processes. Key elements of the program consist of focused senior and site management oversight, design and process improvements, and increased employee awareness of expectations. During the third quarter of 2011, communications from senior leadership continued to reinforce expectations and to maintain employee awareness. Progress was made in developing design controls and work process improvements for both of these risk areas.

OPG believes that partnership with its unions is an important element of its strong safety culture and has embarked on a number of safety initiatives in 2011 including joint initiatives to improve falling object prevention and work protection processes. In October 2011, Joint Health and Safety Committee members from across the province met in a joint forum to discuss their role regarding new regulatory requirements and to share lessons learned for common health and safety risks to implement at their respective sites.

Generation Development

Generation development opportunities pursued by OPG include capacity expansion, life extension opportunities, and the construction of new generating stations. Pursuing opportunities to leverage existing sites and assets allows OPG to maximize benefits from these assets, and to reduce the environmental impact of meeting Ontario's electricity demands. OPG's major projects include nuclear station refurbishment, new nuclear generation, new hydroelectric generation and plant upgrades, and the conversion of selected coal-fired generating units to alternate fuels. OPG's strategy and initiatives to finance these generation development projects are discussed under the heading, *Liquidity and Capital Resources*.

New Nuclear Units

In August 2011, the Joint Review Panel overseeing the Darlington New Nuclear Project Environmental Assessment submitted its report to the federal Minister of Environment. The Joint Review Panel concluded that the project is not likely to cause significant adverse environmental effects, given mitigation. The federal government will now prepare its response for approval by the Governor in Council, with a final determination of whether or not the Environmental Assessment ("EA") should be accepted. The EA has been challenged by way of judicial review in the Federal Court of Canada on the grounds that the Joint Review Panel report failed to comply with requirements of the *Canadian Environmental Assessment Act,* and that the hearing deprived the applicants of certain procedural rights.

Darlington Refurbishment Project

The EA for the Darlington Refurbishment project, which forms the basis of the regulatory scope, is on track for submission to the CNSC in late 2011. A third party report on the Integrated Safety Review ("ISR") was provided to OPG in the third quarter of 2011 and its recommendations were addressed. A stakeholder review of the final ISR was completed and the final report was submitted to the CNSC.

As part of the EA process, OPG has completed field and technical studies, and is finalizing the EIS and the associated Technical Support Documents. The preliminary assessment results have undergone external peer review by local municipalities and have also been shared with key stakeholders.

Negotiations with two proponents of the Retube and Feeder Replacement contract are continuing. Construction on the Darlington Energy Complex continues and remains on track for occupancy in the fall of 2013. Additional infrastructure related work, including upgrades to the water and sewer system, has commenced.

Pickering B Continued Operations

OPG is undertaking a coordinated set of initiatives to evaluate the opportunity to continue safe and reliable operations of Pickering B for an additional four to six years beyond its nominal end of life. Work is progressing by incorporating incremental life cycle management inspections and maintenance into the scope, cost, and duration of the outage programs along with other plant equipment improvements. In the third quarter of 2011, OPG began execution of the second of several major planned outages on Unit 6 at the Pickering B generating station targeted at improving the reliability of the generating station and collecting necessary inspection results to support continued operation.

Niagara Tunnel

The tunnel boring machine ("TBM") mining activity has been completed and the TBM disassembly is in progress. Lining installation activities at the Niagara Tunnel continue. Installation of the lower one-third of the permanent concrete lining had reached 7,625 metres by July 2, 2011 when this work was temporarily interrupted to do reinforcement repair work in the 6,050 metre area of the tunnel. This lining work is expected to resume in January 2012. All other tunnel lining activities are continuing. At September 30, 2011, restoration of the circular cross-section of the tunnel before installation of the upper two-thirds of the concrete lining was behind schedule at 5,170 metres, but is not expected to delay tunnel completion. Installation of the upper two-thirds of the concrete lining has progressed 4,200 metres and is on schedule. Contact grouting to fill the space between the concrete lining and impermeable membrane has progressed 1,450 metres. Pre-stress grouting to complete the attachment of the concrete liner with the surrounding rock commenced in August 2011 and at September 30, 2011 has progressed 400 metres.

Some uncertainty with respect to the cost and schedule for the liner installation will continue. Notwithstanding the uncertainty, the Niagara Tunnel is expected to be completed within the approved budget of $1.6 billion and the approved project completion date of December 2013. Upon completion of the project, the average annual generation from the Sir Adam Beck generating stations will increase by approximately 1.6 TWh.

The capital project expenditures for the three and nine month periods ended September 30, 2011 were $57 million and $209 million, respectively. As at September 30, 2011, the life-to-date capital expenditures were $1,089 million.

Lower Mattagami

The Lower Mattagami River project will increase the capacity of the four generating stations on the Lower Mattagami River by 438 MW. During the third quarter of 2011, additional rock consolidation work was undertaken at the Smoky Falls site to remediate unanticipated geological conditions while concrete operations continued. At the Little Long site, concrete operations commenced and the draft tube formwork was installed. The cofferdam installation commenced at the Kipling site and the Harmon site cofferdam installation was completed. As at September 30, 2011, the life-to-date capital expenditures were $619 million. The project is expected to be completed within the approved budget of $2.6 billion and the approved completion date of June 2015. In September 2011, the Lower Mattagami Limited Partnership agreement was amended and restated to include the Moose Cree First Nation ("MCFN"), and their wholly owned Amisk-oo-Skow Finance Corporation, as limited partners and to enable MCFN to acquire up to a 25 percent limited partnership interest, as contemplated in the existing comprehensive agreement.

Conversion of Coal-Fired Units

The strategy to convert coal-fired units to alternative fuels continues to advance and is reflective of the changing operating environment in Ontario. This includes the phase-out of coal-fired generation and conversion of units to alternative fuels such as biomass, natural gas and gas-biomass dual-fuelled. Before OPG can proceed with unit conversions, a mechanism is required for recovery of capital and on-going costs. OPG is seeking opportunities to establish a cost recovery contract for the coal-fired units at the Atikokan and Thunder Bay generating stations for the period leading up to their potential future conversions to alternative fuels, as proposed in the Energy Plan and the Supply Mix Directive.

The conversion of the Atikokan generating station to biomass is currently in the definition phase. OPG and the OPA are continuing to negotiate the Atikokan Biomass Energy Supply Agreement. OPG is proceeding with detailed engineering, and the negotiation of the engineering, procurement, and construction contract for the conversion of the Atikokan generating station to biomass fuel. The formal negotiation of fuel supply contracts began in October 2011 consistent with the progress on the energy supply agreement negotiation with the OPA.

The conversion of two units at the Thunder Bay generating station to natural gas is currently in the definition phase and OPG continues to proceed with detailed engineering. On August 17, 2011, the Minister of Energy issued a directive to the OPA to negotiate a long-term energy supply contract with OPG, for the conversion of two coal-fired units at the Thunder Bay generating station to natural gas. Discussions for a long-term supply contract with the OPA began in October 2011. While an energy supply agreement is still required for the conversion, OPG has been requested by the Shareholder to continue the work associated with the required gas infrastructure consistent with the Energy Plan. Union Gas has announced the start of their public process for pipeline routing to the generating station.

As outlined in the Energy Plan and Supply Mix Directive, OPG is also exploring the possible conversion of some units at the Lambton and Nanticoke generating stations to natural gas, if required for system reliability. Due to the long lead-time required for a Nanticoke gas pipeline, Union Gas has begun conducting technical and environmental studies and public consultation leading to the identification of the pipeline route to Nanticoke. Similar pipeline routing studies are also being undertaken at Lambton.

Developing and Acquiring Talent

Skilled Workforce

As of September 30, 2011, OPG had approximately 90 percent of its regular labour force represented by a union. The current collective agreement between OPG and the Power Workers' Union (the "PWU") has a three-year term (April 1, 2009 – March 31, 2012). OPG is currently preparing for collective bargaining with the PWU. An agenda exchange is scheduled for December 2011 followed by formal negotiations commencing in January 2012. The current collective agreement with the Society of Energy Professionals has a two-year term (January 1, 2011 to December 31, 2012).

In addition to the regular workforce, construction work is performed through 22 craft unions with established bargaining rights on OPG facilities. These bargaining rights are either through the Electrical Power Systems Construction Association ("EPSCA") or directly with OPG. OPG, in conjunction with EPSCA, was actively involved in all aspects of negotiations. All of the construction agreements expired on April 30, 2010 and have been re-negotiated.

KEY GENERATION AND FINANCIAL PERFORMANCE INDICATORS

Key performance indicators that directly pertain to OPG's mandate and corporate strategies are measures of production efficiency, cost effectiveness, and environmental performance. OPG evaluates the performance of its generating stations using a number of key performance indicators, which vary depending on the generating technology. These indicators are defined in the 2010 annual MD&A and are discussed in the *Discussion of Operating Results by Business Segment* section.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

This section summarizes OPG's key results by segment for the three and nine month periods ended September 30, 2011 and 2010. The following table provides a summary of revenue, income (loss) before interest and income taxes, and generation by business segment:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars – except where noted)	**2011**	**2010**	**2011**	**2010**
Revenue				
Regulated – Nuclear Generation	**794**	784	**2,295**	2,234
Regulated – Nuclear Waste Management	**18**	12	**42**	33
Regulated – Hydroelectric	**176**	180	**550**	548
Unregulated – Hydroelectric	**94**	107	**392**	359
Unregulated – Thermal	**171**	279	**451**	780
Other	**39**	41	**119**	122
Elimination	**(17)**	(12)	**(40)**	(32)
	1,275	1,391	**3,809**	4,044
Income (loss) before interest and income taxes				
Regulated – Nuclear Generation	**146**	155	**275**	178
Regulated – Nuclear Waste Management	**(192)**	122	**(240)**	(27)
Regulated – Hydroelectric	**73**	75	**256**	246
Unregulated – Hydroelectric	**(2)**	15	**113**	100
Unregulated – Thermal	**(56)**	(5)	**(108)**	(40)
Other	**39**	19	**79**	57
	8	381	**375**	514
Electricity generation (TWh)				
Regulated – Nuclear Generation	**12.6**	11.8	**36.6**	33.4
Regulated – Hydroelectric	**4.9**	4.8	**14.5**	14.2
Unregulated – Hydroelectric	**2.0**	1.9	**10.1**	8.1
Unregulated – Thermal	**1.9**	4.2	**3.1**	11.2
	21.4	22.7	**64.3**	66.9

Regulated – Nuclear Generation Segment

(millions of dollars)	Three Months Ended September 30 2011	2010	Nine Months Ended September 30 2011	2010
Regulated generation sales	**698**	647	**2,024**	1,824
Variance accounts	**(6)**	69	**23**	211
Other	**102**	68	**248**	199
Total revenue	**794**	784	**2,295**	2,234
Fuel expense	**70**	57	**189**	157
Variance accounts	**(4)**	(14)	**(10)**	(22)
Total fuel expense	**66**	43	**179**	135
Gross margin	**728**	741	**2,116**	2,099
Operations, maintenance and administration	**441**	478	**1,461**	1,598
Depreciation and amortization	**135**	98	**363**	291
Property and capital taxes	**6**	10	**20**	32
Income before other gains, interest and income taxes	**146**	155	**272**	178
Other gains	**-**	-	**(3)**	-
Income before interest and income taxes	**146**	155	**275**	178

Income before interest and income taxes from the Regulated – Nuclear generation segment was $146 million for the third quarter of 2011 compared to $155 million for the third quarter of 2010. The decrease in income before interest and income taxes for the third quarter of 2011 compared to the same period in 2010 was primarily due to lower revenue related to the regulatory variance accounts, higher depreciation and amortization expense, and an increase in fuel expense. This decrease was partially offset by higher generation revenue and lower OM&A expenses.

The increase in generation revenue during the three months ended September 30, 2011 compared to the same period in 2010 was primarily due to a higher generation volume of 0.8 TWh.

The decrease in revenue related to the regulatory variance accounts during the third quarter of 2011 compared to the same quarter of 2010 was primarily related to the cessation of additions to the Tax Loss Variance Account based on the OEB's decision effective March 1, 2011. The decrease in revenue related to the regulatory variance accounts was also due to the Bruce Lease Net Revenues Variance Account. During the three months ended September 30, 2011 and 2010, OPG recognized a decrease in the fair value of the derivative liability embedded in the Bruce lease of $13 million and an increase of $9 million, respectively, as a result of changes in the expected future annual arithmetic average of the Hourly Ontario Electricity Price. Since the changes in the fair value of this derivative are recorded in non-electricity generation revenue with a corresponding change in the regulatory asset related to the Bruce Lease Net Revenues Variance Account, there is no income impact of the change in the fair value of the derivative liability.

The increase in depreciation and amortization expense of $37 million during the third quarter of 2011 compared to the same quarter in 2010 was primarily due to higher amortization expense related to the recovery of regulatory balances as a result of the OEB's March 2011 decision on the new regulated prices.

The increase in fuel expense during the third quarter of 2011 compared to the same quarter in 2010 was primarily due to higher nuclear fuel prices and the cessation of the Nuclear Fuel Cost Variance Account as a result of the OEB's March 2011 decision. The increase in fuel expense was also due to higher generation volumes.

The decrease in OM&A expenses of $37 million during the third quarter of 2011 compared to the same period in 2010 was primarily due to lower planned outage and project activities, and a decrease in expenditures for new nuclear generation development and capacity refurbishment activities, net of the impact of related regulatory variance accounts. The decrease in OM&A expenses was partially offset by higher pension and OPEB costs net of the impact of the Pension and OPEB Cost Variance Account. The increase in pension and OPEB costs was largely as a result of lower discount rates in 2011.

Income before interest and income taxes was $275 million for the nine months ended September 30, 2011 compared to $178 million during the same period in 2010. The increase in income was primarily due to higher generation revenue and lower OM&A expenses.

The increase in generation revenue for the nine months ended September 30, 2011 compared to the same period in 2010 was primarily due to a higher generation volume of 3.2 TWh.

The decrease in OM&A expenses during the nine months ended September 30, 2011 compared to the same period in 2010 was primarily due to lower planned outage and project activities, and a decrease in expenditures for new nuclear generation development and capacity refurbishment activities, net of the impact of related regulatory variance accounts. The decrease was partially offset by higher pension and OPEB costs net of the impact of the Pension and OPEB Cost Variance Account and higher maintenance costs.

The increase in income before interest and income taxes for the nine months ended September 30, 2011 compared to the same period in 2010 was partially offset by lower revenue related to the cessation of additions to the Tax Loss Variance Account effective March 1, 2011, and higher amortization expense related to the recovery of regulatory balances.

The unit capability factors for each of the nuclear stations and the Production Unit Energy Cost ("PUEC") for the three and nine month periods ended September 30, 2011 and 2010 are as follows:

	Three Months Ended September 30		**Nine Months Ended September 30**	
	2011	**2010**	**2011**	**2010**
Unit Capability Factor *(%)*				
Darlington	**97.5**	86.3	**93.9**	87.4
Pickering A	**79.3**	65.9	**73.9**	54.5
Pickering B	**77.5**	86.9	**77.3**	75.3
Nuclear PUEC *($/MWh)*	**39.16**	41.99	**43.20**	48.67

For the three months ended September 30, 2011, the capability factor for the Darlington generating station increased compared to the same period in 2010. The improvement was due to a decrease in the number of planned and unplanned outage days. The higher capability factor at the Pickering A generating station during the third quarter of 2011 compared to the same quarter in 2010 was primarily due to the timing of planned outages. The lower capability factor at the Pickering B generating station during the third quarter of 2011 was primarily the result of an extension to a planned outage on Unit 5.

The decrease in Nuclear PUEC for the three months ended September 30, 2011 compared to the same period in 2010 was primarily due to higher generation and lower OM&A expenses, partially offset by higher fuel expense.

For the nine months ended September 30, 2011, the higher capability factor at the Darlington generating station compared to the same period in 2010 was primarily due to a decrease in the planned and unplanned outage days. The higher capability factors at the Pickering A and B generating stations during the nine months ended September 30, 2011 compared to the same period in 2010 primarily reflected the lower planned outage days at these stations, as all six units were shutdown during the Pickering Vacuum Building Outage in the second quarter of 2010. The increase in the capability factor at the Pickering A generating station for the nine months ended September 30, 2011 compared to the same period in 2010 was partially offset by higher unplanned outage days.

The decrease in Nuclear PUEC for the nine months ended September 30, 2011 compared to the same period in 2010 was primarily due to higher generation and lower OM&A expenses, partially offset by higher fuel expense.

Regulated – Nuclear Waste Management Segment

(millions of dollars)	Three Months Ended September 30 2011	2010	Nine Months Ended September 30 2011	2010
Revenue	**18**	12	**42**	33
Operations, maintenance and administration	**19**	14	**47**	38
Accretion on fixed asset removal and nuclear waste management liabilities	**175**	163	**521**	490
Losses (earnings) on nuclear fixed asset removal and nuclear waste management funds	**16**	(287)	**(286)**	(468)
(Loss) income before interest and income taxes	**(192)**	122	**(240)**	(27)

Loss before interest and income taxes for the Regulated – Nuclear Waste Management Segment was $192 million for the three months ended September 30, 2011 compared to income before interest and income taxes of $122 million for the same period in 2010. Loss before interest and income taxes for the nine months ended September 30, 2011 was $240 million compared to $27 million for the nine months ended September 30, 2010. The higher losses before interest and incomes taxes for the three and nine month periods ended September 30, 2011 compared to the same periods in 2010 were primarily due to lower earnings from the Nuclear Funds and higher accretion expense.

The lower earnings from the Nuclear Funds for the three and nine month periods ended September 30, 2011 compared to the same periods in 2010 were primarily due to lower income from the Decommissioning Fund resulting from a decline in the valuation levels of global financial markets during the third quarter of 2011.

The increase in accretion expense for the three and nine month periods ended September 30, 2011 compared to the same periods in 2010 was primarily due to an increase in the present value of the Nuclear Liabilities due to the passage of time.

Regulated – Hydroelectric Segment

(millions of dollars)	Three Months Ended September 30 2011	2010	Nine Months Ended September 30 2011	2010
Regulated generation sales	**174**	178	**514**	524
Variance accounts	**(4)**	(5)	**10**	-
Other	**6**	7	**26**	24
Total revenue	**176**	180	**550**	548
Fuel expense	**74**	68	**191**	183
Variance accounts	**(3)**	(5)	**(1)**	(7)
Total fuel expense	**71**	63	**190**	176
Gross margin	**105**	117	**360**	372
Operations, maintenance and administration	**25**	23	**76**	70
Depreciation and amortization	**8**	16	**30**	48
Property and capital taxes (recovery) expense	**(1)**	3	**(2)**	8
Income before interest and income taxes	**73**	75	**256**	246

For the three months ended September 30, 2011, income before interest and income taxes for the Regulated – Hydroelectric segment was $73 million compared to $75 million for the same period in 2010. The decrease in income was primarily due to lower generation revenue as a result of lower sales prices related to the OEB's March 2011 decision on the new regulated prices, partially offset by higher generation volume, and lower depreciation and amortization expense. The decrease in depreciation and amortization expense was primarily due to lower amortization expense related to regulatory balances as a result of the OEB's March 2011 decision.

For the nine months ended September 30, 2011, income before interest and income taxes for the Regulated – Hydroelectric segment was $256 million compared to $246 million for the same period in 2010. The increase in income was primarily due to lower depreciation and amortization expense, and a lower property and capital taxes expense primarily as a result of the elimination of capital tax as of July 2010. The increase was partially offset by lower generation revenue as a result of lower sales prices due to the OEB's March 2011 decision on the new regulated prices.

The availability, Equivalent Forced Outage Rate ("EFOR") and OM&A expense per MWh for the Regulated – Hydroelectric segment for the three and nine month periods ended September 30, 2011 and 2010 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	**2010**	**2011**	**2010**
Availability *(%)*	**93.4**	93.0	**91.0**	92.8
EFOR *(%)*	**0.7**	0.4	**0.9**	0.3
Regulated – Hydroelectric OM&A expense per MWh *($/MWh)*	**5.10**	4.79	**5.24**	4.93

The increase in availability during the three months ended September 30, 2011 compared to the same period in 2010 was primarily due to a decrease in planned outages. The decrease in availability during the nine months ended September 30, 2011 compared to the same period in 2010 was primarily due to an increase in planned maintenance and project outages in 2011. The continuing high availability and low EFOR reflected the strong performance of these hydroelectric stations.

The increase in OM&A expense per MWh for the three and nine month periods ended September 30, 2011 compared to the same periods in 2010 was due to higher OM&A expenses, partially offset by higher generation.

Unregulated – Hydroelectric Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**
Spot market sales, net of hedging instruments	**74**	91	**333**	325
Other	**20**	16	**59**	34
Total revenue	**94**	107	**392**	359
Fuel expense	**13**	10	**55**	42
Gross margin	**81**	97	**337**	317
Operations, maintenance and administration	**60**	64	**168**	165
Depreciation and amortization	**20**	18	**56**	49
Property and capital taxes	**3**	-	**-**	3
(Loss) income before interest and income taxes	**(2)**	15	**113**	100

Loss before interest and income taxes for the three months ended September 30, 2011 was $2 million compared to income before interest and income taxes of $15 million for the same period in 2010. The decrease in income before interest and income taxes for the three months ended September 30, 2011 compared to the same period in 2010 was primarily due to lower generation revenue as a result of the impact of lower electricity prices primarily due to a decrease in Ontario spot market prices.

Income before interest and income taxes for the nine months ended September 30, 2011 was $113 million compared to $100 million for the same period in 2010. The increase in income was primarily due to higher revenue, partially offset by an increase in fuel expense. The increase in revenue for the nine months ended September 30, 2011 compared to the same period in 2010 was primarily due to an increase in generation volume due to higher water flows in 2011, and revenue from an energy supply agreement related to the Upper Mattagami generating stations. These stations were placed in service during the fourth quarter of 2010. The increase in revenue was partially offset by the impact of lower average sales prices.

The increase in fuel expense for the three and nine month periods ended September 30, 2011 compared to the same periods in 2010 was primarily due to higher generation volume.

The availability, EFOR and OM&A expense per MWh for Unregulated – Hydroelectric segment for the three and nine month periods ended September 30, 2011 and 2010 are as follows:

	Three Months Ended September 30		**Nine Months Ended September 30**	
	2011	**2010**	**2011**	**2010**
Availability *(%)*	**87.5**	87.5	**91.9**	91.6
EFOR *(%)*	**3.4**	4.3	**1.5**	2.4
Unregulated – Hydroelectric OM&A expense per MWh *($/MWh)*	**30.00**	28.95	**16.63**	19.26

Availability for the three months ended September 30, 2011 and September 30, 2010 was 87.5 percent. Availability for the nine months ended September 30, 2011 and September 30, 2010 was 91.9 percent and 91.6 percent, respectively. EFOR decreased for the three and nine month periods ended September 30, 2011 compared to the same periods in 2010 as a result of a decrease in unplanned outages at the Northeast and Ottawa St. Lawrence Plant Groups. The high availability and low EFOR reflected the continuing strong performance of these hydroelectric stations.

The increase in OM&A expense per MWh in the third quarter of 2011 compared to the same quarter in 2010 was primarily due to higher OM&A expenses excluding expenses related to past grievances by First Nations, partially offset by the impact of higher generation. The decrease in OM&A expense per MWh for the nine months ended September 30, 2011 compared to the same period in 2010 was primarily due to the impact of higher generation.

Unregulated – Thermal Segment

(millions of dollars)	Three Months Ended September 30 2011	2010	Nine Months Ended September 30 2011	2010
Spot market sales, net of hedging instruments	**73**	224	**108**	498
Contingency support agreement	**64**	18	**259**	167
Other	**34**	37	**84**	115
Total revenue	**171**	279	**451**	780
Fuel expense	**67**	143	**142**	363
Gross margin	**104**	136	**309**	417
Operations, maintenance and administration	**96**	106	**298**	335
Depreciation and amortization	**21**	29	**64**	83
Accretion on fixed asset removal liabilities	**2**	2	**5**	5
Property and capital taxes	**4**	4	**12**	9
Restructuring	**19**	-	**19**	25
Loss before other losses, interest and income taxes	**(38)**	(5)	**(89)**	(40)
Other losses	**18**	-	**19**	-
Loss before interest and income taxes	**(56)**	(5)	**(108)**	(40)

Loss before interest and income taxes for the three months ended September 30, 2011 was $56 million compared to $5 million for the same period in 2010. Loss before interest and income taxes for the nine months ended September 30, 2011 was $108 million compared to $40 million for the same period in 2010.

Gross margin decreased for the three and nine month periods ended September 30, 2011 compared to the same periods in 2010 primarily due to a significant reduction in generation volume and lower electricity sales prices. Electricity generation for the three and nine month periods ended September 30, 2011 decreased compared to the same periods in 2010 by 2.3 TWh and 8.1 TWh, respectively. The gross margin for the nine months ended September 30, 2011 was also unfavourably impacted by higher fuel-related costs pertaining to favourable adjustments in thermal inventory during the second quarter of 2010, and adjustments to coal supply contracts during the second quarter of 2011. These decreases in gross margin were partially offset by higher revenue related to the contingency support agreement for the Nanticoke and Lambton generating stations.

The reduction in OM&A expenses for the three and nine month periods ended September 30, 2011 compared to the same periods in 2010 was primarily due to the continuation of the vacancy and overtime management program, and reduced scope of work associated with changing operating profiles and unit closures at Nanticoke in 2011.

Depreciation and amortization expense decreased for the three and nine month periods ended September 30, 2011 compared to the same periods in 2010 due to the recognition of accelerated depreciation related to four unit closures in 2010 compared to accelerated depreciation for two units in 2011.

Restructuring charges of $19 million were recorded during the three and nine month periods ended September 30, 2011 due to the recognition of severance costs related to the planned safe shutdown of two coal-fired units at the Nanticoke generating station in 2011. During the nine months ended September 30, 2010, restructuring charges of $25 million were recognized related to the closure of four coal-fired units in 2010.

In September, OPG completed a review of the ARO for most of its thermal stations. As a result of this review, the ARO estimate has increased, resulting in a loss of $18 million being recorded in the Thermal business segment for the three and nine month periods ended September 30, 2011. A gain related to the decommissioned R.L. Hearn generating station is included in the Other segment. The net impact of the review is discussed in the *Changes in Accounting Policies and Estimates* section.

The EFOR and OM&A expense per MW for Unregulated – Thermal segment for the three and nine month periods ended September 30, 2011 and 2010 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	**2010**	**2011**	**2010**
EFOR *(%)*	**13.1**	10.7	**9.5**	7.0
Unregulated – Thermal OM&A expense per MW *($000/MW)*	**62.1**	52.6	**63.5**	54.9

The higher EFOR for the three and nine month periods ended September 30, 2011 compared to the same periods in 2010 was primarily due to a higher number of unplanned outage days at the Nanticoke and Lambton generating stations. The higher number of unplanned outage days is consistent with the implementation of a management strategy, which entails carefully managing outage expenditures while ensuring the units are available as required during a period of reduced production.

The increase in OM&A expense per MW during the three and nine month periods ended September 30, 2011 compared to the same periods in 2010 reflected the reduction in OPG's thermal generating capacity in late 2010 resulting from the unit closures and the reduction in capacity at the Nanticoke generating station during the third quarter of 2011, partially offset by lower OM&A expenses for the three and nine month periods ended September 30, 2011.

Other

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**
Revenue	**39**	41	**119**	122
Operations, maintenance and administration	**4**	4	**16**	11
Depreciation and amortization	**13**	14	**37**	44
Property and capital taxes	**3**	3	**8**	11
Income before other (gains) losses, interest and income taxes	**19**	20	**58**	56
Other (gains) losses	**(20)**	1	**(21)**	(1)
Income before interest and income taxes	**39**	19	**79**	57

Income before interest and income taxes for the Other segment during the three months ended September 30, 2011 and 2010 was $39 million and $19 million, respectively. Income before interest and income taxes for the nine months ended September 30, 2011 and 2010 was $79 million and $57 million, respectively. The increase in income before interest and income taxes for the three and nine month periods ended September 30, 2011 compared to the same periods in 2010 was primarily due to a gain recognized as a result of the ARO review conducted for most of its thermal stations. The ARO associated with the decommissioned R.L. Hearn generating station was reduced resulting in a gain of $20 million being recorded in the Other segment.

Interconnected purchases and sales, including those to be physically settled, and unrealized mark-to-market gains and losses on energy trading contracts, are disclosed on a net basis in the consolidated statements of income. For the three months ended September 30, 2011, if disclosed on a gross basis, revenue and power purchases would have increased by $21 million (three months ended September 30, 2010 – $19 million). For the nine months ended September 30, 2011, if disclosed on a gross basis, revenue and power purchases would have increased by $59 million (nine months ended September 30, 2010 – $52 million).

With the exception of the derivative embedded in the Bruce lease, which is reflected in the Regulated – Nuclear Generation segment, the changes in the fair value of derivative instruments not qualifying for hedge accounting are recorded in revenue, and the fair value of derivative instruments are carried on the consolidated balance sheets as assets or liabilities at fair value. The carrying amounts and notional quantities of the derivative instruments are disclosed in Note 11 of OPG's unaudited interim consolidated financial statements for the third quarter of 2011.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation ("OEFC"), and capital market financing. These sources are utilized for multiple purposes including: investments in plants and technologies; funding obligations such as contributions to the pension funds and the Nuclear Funds; and to service and repay long-term debt.

Changes in cash and cash equivalents for the three and nine month periods ended September 30, 2011, and 2010 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**
Cash and cash equivalents, beginning of period	**654**	103	**280**	71
Cash flow provided by operating activities	**431**	359	**993**	687
Cash flow used in investing activities	**(266)**	(261)	**(804)**	(665)
Cash flow (used in) provided by financing activities	**(4)**	141	**346**	249
Net increase	**161**	239	**535**	271
Cash and cash equivalents, end of period	**815**	342	**815**	342

Operating Activities

Cash flow provided by operating activities for the three months ended September 30, 2011 was $431 million compared to $359 million for the same period in 2010. The increase in cash flow was primarily due to lower OM&A expenditures and lower fuel purchases. This increase was partially offset by lower cash receipts as a result of lower generation revenue in the third quarter of 2011 compared to the same period in 2010.

Cash flow provided by operating activities for the nine months ended September 30, 2011 was $993 million compared to $687 million for the same period in 2010. The increase in cash flow was primarily due to lower OM&A expenditures, lower fuel purchases and lower tax instalments. This increase was partially offset by lower cash receipts as a result of lower generation revenue for the nine months ended September 30, 2011 compared to the same period in 2010.

An actuarial valuation of the OPG registered pension plan was completed as of January 1, 2011. Based on the actuarial valuation, OPG will increase its annual contribution to the plan from $270 million in 2010 to $300 million in 2011. The annual contributions for 2012 and 2013 will be adjusted for changes in current service costs in each year. OPG will continue to assess the requirements for contributions to the pension plan. The next actuarial valuation for funding purposes must have an effective date no later than January 1, 2014.

Investing Activities

Cash flow used in investing activities during the third quarter of 2011 was $266 million compared to $261 million for same quarter in 2010. Cash flow used in investing activities during the nine months ended September 30, 2011 was $804 million compared to $665 million for same period in 2010.

The increase in cash flow used in investing activities for the three months ended September 30, 2011 compared to the same period in 2010 was primarily due to higher capital expenditures for the Darlington Refurbishment project and the Lower Mattagami River project. This increase was largely offset by lower capital expenditures for the Upper Mattagami and Hound Chute project, which was placed in service in the fourth quarter of 2010.

The increase in cash flow used in investing activities for the nine months ended September 30, 2011 compared to the same period in 2010 was primarily due to higher capital expenditures for the Lower Mattagami River project, the Niagara Tunnel project, and the Darlington Refurbishment project. This increase was partially offset by lower capital expenditures for the Upper Mattagami and Hound Chute project, and other nuclear capital initiatives.

OPG's forecast capital expenditures for 2011 are approximately $1.2 billion, which includes amounts for hydroelectric development and nuclear refurbishment.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year tranches. In May 2011, OPG renewed and extended one $500 million tranche to May 18, 2015. The other $500 million tranche has a maturity date of May 20, 2013. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. As at September 30, 2011, no commercial paper was outstanding (December 31, 2010 – nil). OPG had no other outstanding borrowings under the bank credit facility as at September 30, 2011 and December 31, 2010.

During 2010, the Lower Mattagami Energy Limited Partnership ("LME") established a $700 million bank credit facility to support the initial construction phase for the Lower Mattagami project and launched a commercial paper program. In July 2011, OPG extended the maturity date of this credit facility to August 17, 2015. As at September 30, 2011, no commercial paper was outstanding under this program (December 31, 2010 – $155 million). In March 2011, OPG executed a $700 million credit facility with the OEFC in support of the Lower Mattagami project. As at September 30, 2011, there were no outstanding borrowings under this credit facility.

On May 17, 2011, senior notes totalling $475 million were issued by the LME. The senior notes have interest rates of 4.3 percent for notes of $225 million maturing in 2021 and 5.1 percent for notes of $250 million maturing in 2041. On October 25, 2011, senior notes totalling $96 million were issued by the LME. These senior notes have an interest rate of 2.6 percent and mature in 2015. The notes are secured by the assets of the Lower Mattagami project, including existing operating facilities and facilities being constructed.

As at September 30, 2011, OPG maintained $25 million (December 31, 2010 – $25 million) of short-term, uncommitted overdraft facilities, and $319 million (December 31, 2010 – $319 million) of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans, and for other purposes. At September 30, 2011, there was a total of $279 million of Letters of Credit issued (December 31, 2010 – $281 million), which included $254 million for the supplementary pension plans (December 31, 2010 – $254 million), $18 million for general corporate purposes (December 31, 2010 – $20 million) and $7 million related to the operation of the PEC (December 31, 2010 – $7 million).

During 2010, OPG executed an amended Niagara Tunnel project credit facility for an amount up to $1.6 billion. As at September 30, 2011, advances under this facility were $815 million (December 31, 2010 – $690 million), which included $50 million of new borrowing during the third quarter of 2011.

As at September 30, 2011, OPG's long-term debt outstanding with the OEFC was $3.9 billion, of which $400 million must be repaid or refinanced within the next three years. To ensure that adequate financing resources were available beyond its $1 billion commercial paper program backed by the revolving committed bank credit facility, OPG reached an agreement with the OEFC in March 2011 for a $375 million credit facility to refinance notes as they mature over the period from January 2011 to December 2011. Refinancing under this agreement totalled $300 million as at September 30, 2011.

During the third quarter of 2011, OPG settled a claim and arbitration with a certain First Nation in one settlement agreement. OPG was directed by its shareholder to pay a part of the shareholder's portion of the settlement liability on its behalf. As a result, OPG recorded a distribution of $14 million to the First Nation, which was recorded as a reduction to retained earnings in the third quarter of 2011. This settlement did not have a material impact on the Company's financial position.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

(millions of dollars)	As At September 30 2011	 December 31 2010	Explanation of change
Accounts receivable	**168**	270	The decrease was primarily due to lower receivables from the IESO as a result of lower electricity generation volumes in September 2011 compared to December 2010.
Nuclear fixed asset removal and nuclear waste management funds	**11,562**	11,246	The increase was primarily due to earnings on, and contributions to, the Used Fuel Fund. This increase was partially offset by losses on the Decommissioning Fund and the reimbursement of program expenditures from the Nuclear Funds.
Regulatory assets	**1,468**	1,559	The decrease was primarily due to the amortization of regulatory asset balances as a result of the OEB's March 2011 decision and the reduction in the regulatory asset for future income taxes. This impact was partially offset by the additions to the Bruce Lease Net Revenues Variance Account, primarily related to earnings on the Nuclear Funds being lower than those reflected in the current regulated prices established by the OEB, and the recognition of a regulatory asset related to the Pension and OPEB Cost Variance Account pursuant to the OEB's June 2011 decision.
Fixed asset removal and nuclear waste management liabilities	**13,135**	12,704	The increase was primarily a result of accretion expense due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under Canadian GAAP, are either not recorded in the Company's consolidated financial statements or are recorded in the Company's consolidated financial statements using amounts that differ from the full contract amounts.

Principal off-balance sheet activities that OPG undertakes include securitization of certain accounts receivable agreements, guarantees, which provide financial or performance assurance to third parties on behalf of certain subsidiaries, and long-term fixed price contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies, including the impact of future accounting pronouncements, are outlined in Note 3 to the audited annual consolidated financial statements as at and for the year ended December 31, 2010. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required concerning matters that are inherently uncertain, and could result in materially different amounts being reported under different conditions or assumptions.

Business Combinations, Consolidated Financial Statements, and Non-controlling Interests

Effective January 1, 2011, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 1582 *Business Combinations* ("Section 1582"), Section 1601 *Consolidated Financial Statements* ("Section 1601"), and Section 1602 *Non-controlling Interests* ("Section 1602"). Section 1582 specifies a number of changes, including an expanded definition of a business, a requirement to measure all business acquisitions at fair value, and a requirement to recognize acquisition-related costs as expenses. Section 1601 establishes the standards for preparing consolidated financial statements. Section 1602 specifies that non-controlling interests be treated as a separate component of equity, not as a liability or other item outside of equity. These standards shall be applied prospectively to business combinations whose acquisition date is on or after the date of adoption. As a result of adopting Section 1602, the Company has reclassified its non-controlling interests as a separate component of equity. The adoption of Section 1582 and Section 1601 did not have a material impact on the Company's unaudited interim consolidated financial statements for the three and nine month periods ended September 30, 2011.

Thermal Asset Retirement Obligation

In September 2011, OPG completed a review of the ARO for most of its thermal generating stations. As a result of the review, the ARO estimate has been reduced by $4 million. The reduction reflected an increase in the expected cost recovery for station equipment and materials, partially offset by an increase in the demolition estimate. As a result of the ARO adjustment, OPG recorded a corresponding reduction to Property, Plant and Equipment ("PP&E") in the Unregulated – Thermal segment of $2 million and a net gain of $2 million as at and during the three months ended September 30, 2011, respectively. The gain has been recorded in the Thermal and Other segments consistent with the segment classification of the stations as other (gains) losses.

CONVERSION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS

Introduction to Conversion Project

OPG's IFRS conversion project progressed during the third quarter of 2011, including regular communications to executive management, finance employees and other stakeholders, and the Audit and Finance Committee of the Board of Directors. This section provides an update with respect to the disclosure included in the 2010 annual MD&A and the MD&A for the first and second quarters of 2011 under the heading, *Conversion to International Financial Reporting Standards*.

Accounting Policy Decisions and Anticipated Impacts

During the third quarter of 2011, OPG continued to evaluate its accounting policy options under IFRS and to collect data, which will be used to report 2011 comparative information in its 2012 IFRS interim and annual consolidated financial statements. OPG continues to expect the following areas to be most impacted by its conversion to IFRS: Property, Plant and Equipment; Fixed Asset Removal and Nuclear

Waste Management Liabilities; Accounts Receivable; Short-term Payables; Employee Benefits; and assets and liabilities related to rate regulated activities. The anticipated impacts on significant areas of OPG's opening balance sheet as of January 1, 2011 are described below.

During the third quarter of 2011, OPG finalized the anticipated impact of IFRS on Fixed Asset Removal and Nuclear Waste Management Liabilities. OPG expects a reduction to Fixed Asset Removal and Nuclear Waste Management Liabilities of approximately $750 million on January 1, 2011. This decrease primarily relates to certain costs that are recognized as part of the estimate for nuclear fixed asset removal and nuclear waste management liabilities under Canadian GAAP that cannot be recognized upon transition to IFRS. In addition, in accordance with International Accounting Standard ("IAS") 37, *Provisions, Contingent Liabilities and Contingent Assets*, a current discount rate is applied to all estimated future cash flows in deriving the liabilities under IFRS, unlike under Canadian GAAP where different discount rates are typically applied to different tranches of future cash flows. OPG is currently assessing the impacts of these adjustments on PP&E for the nuclear operations and opening retained earnings, in light of accounting policy decisions under IFRS 1 for PP&E of operations subject to rate regulation. It is anticipated that these impacts will be finalized prior to the issuance of OPG's 2011 year end consolidated financial statements.

During the third quarter, OPG also determined that it does not anticipate impacts to PP&E at January 1, 2011 as a result of the adoption of IFRS, other than those related to adjustments to Fixed Asset Removal and Nuclear Waste Management Liabilities.

Variance and deferral accounts established by the OEB, including those authorized pursuant to *Ontario Regulation 53/05,* under the *Ontario Energy Board Act, 1998,* meet the definition of a financial asset and financial liability, as defined in IAS 32, *Financial Instruments: Presentation*. The remaining regulatory assets and liabilities currently recognized by OPG under Canadian GAAP will not be recognized upon OPG's adoption of IFRS. As at January 1, 2011, the amount of approximately $700 million in regulatory assets related to future income tax liabilities is expected to be de-recognized.

OPG expects to reduce its deferred pension asset and increase its liability for OPEB upon adoption of IFRS, with a corresponding reduction to opening retained earnings. Under Canadian GAAP, OPG values pension fund assets using market-related values for purposes of determining actuarial gains or losses and the expected return on plan assets. OPG also currently amortizes past service costs over the expected average remaining service life to full eligibility of the employees covered by the plan. IAS 19, *Employee Benefits* ("IAS 19") does not permit the use of market-related values to value pension fund assets, and requires vested past service costs to be expensed immediately. Unvested past service costs must be expensed on a straight-line basis until the benefits become vested. Further, actuarial gains or losses for long-term disability benefits cannot be amortized under IAS 19. It is anticipated that these impacts will be finalized prior to the issuance of OPG's 2011 year end consolidated financial statements. OPG is assessing the impact of the amendment to IAS 19, issued by the International Accounting Standards Board ("IASB") in June 2011, on its consolidated financial statements and accounting policy decisions on transition to IFRS, including whether the amended standard will be early adopted.

OPG has an agreement to sell an undivided co-ownership interest of up to $250 million in its current and future accounts receivable to an independent trust. Under Canadian GAAP, OPG de-recognizes the amount of receivable sold of $250 million from the accounts receivable balance. OPG has determined that the agreement does not meet the de-recognition criteria under IFRS. The estimated amount of $250 million is expected to be recognized in the accounts receivable balance, with a corresponding recognition of a short-term payable, upon adoption of IFRS.

At this time, OPG has not concluded on all of its accounting policy choices upon transition to IFRS. OPG's final accounting policy decisions will be determined once all applicable standards are known upon the January 1, 2012 conversion date.

On-going Monitoring of IASB Projects

The IASB has a number of on-going projects on its agenda including Revenue Recognition, Leases, Financial Instruments, Impairment, and Hedge Accounting. OPG continues to monitor these projects and the impact that any resulting IFRS changes may have on its anticipated accounting policies, financial position or results of operations. OPG will be required to prepare its consolidated financial statements in compliance with each adopted IFRS effective at the end of its first reporting period, which is March 31, 2012. Should there be IFRS changes between March 31, 2012 and December 31, 2012, OPG will be required to reflect such changes in its December 31, 2012 consolidated financial statements and all comparative information.

The following table provides certain elements of the changeover plan and an assessment of the progress OPG has achieved as at September 30, 2011. This information reflects OPG's most recent assumptions and expectations. Circumstances may arise, such as changes in IFRS, regulations or economic conditions, which could change these assumptions or expectations.

Selected Key Activities	Milestones/Deadlines	Progress to Date
Financial statement preparations		
Identify relevant differences between IFRS and current accounting policies and practices and design and implement solutions Evaluate and select one-time and on-going accounting policy alternatives Benchmark findings with peer companies Prepare illustrative financial statements, including note disclosures, to comply with IFRS Quantify the effects of changeover to IFRS	Assessment and quantification of the significant effects of the changeover completed by approximately the fourth quarter of 2011 OPG has elected to defer its adoption of IFRS by one year and expects to assess and quantify the significant effects of the changeover by the fourth quarter of 2011 Final selection of accounting policy alternatives by the changeover date	OPG has progressed on assessing the impact on the following: • The 2011 transitional opening balance sheet; • Accounting policy decisions given on-going work by the IASB; • IFRS 1, *First-time adoption of IFRS* elections; and • Preparation of its consolidated financial statements, including note disclosures.
Training and communications		
Provide training to affected employees of operating units, management and the Board of Directors and relevant committees thereof, including the Audit and Finance Committee Engage subject matter experts to assist in the transition Communicate progress of changeover plan to internal and external stakeholders	Provide timely training in line with changeover milestones. Target to complete training by the end of 2011. Communicate effects of changeover by the fourth quarter of 2011	In 2010, OPG completed detailed training for employees directly engaged in the changeover, and general awareness training to a broader group of finance employees Completed specific and relevant training to 150 finance employees Continued on-going, periodic internal and external communications about OPG's progress Prepared training materials for on-going internal purposes OPG has met with key stakeholders to discuss the impact of converting to IFRS Continued use of third-party subject matter experts to assist in the transition
IT systems		
Identify and address IFRS differences that require changes to financial systems Evaluate and select methods in 2011 to address need for dual record-keeping (i.e., IFRS and Canadian GAAP) for comparatives in 2011	Changes to significant systems and dual record-keeping process completed for the first quarter of 2010 Remaining changes to systems post-dual record-keeping year by the fourth quarter of 2011	System changes are complete to the extent possible. Further changes to information systems would be largely dependent upon future changes to the IFRS standards. Processes and systems are in place to accumulate IFRS data to enable reporting of 2011 comparative information in 2012

Selected Key Activities	Milestones/Deadlines	Progress to Date
Contractual arrangements and compensation		
Identify impact of changeover on contractual arrangements, including financial covenants and employee compensation plans Make any required changes to arrangements and plans	Initial changes and assessments completed by the third quarter of 2010 The assessment of the impact of new standards issued by the IASB on existing and new contractual arrangements is on-going	IFRS differences with potential impacts on financial covenants and compensation plans were identified and discussed with both internal and external parties as required
Internal controls: Internal controls over financial reporting ("ICOFR"), disclosure controls and procedures ("DC&P") and related communications		
Revise existing internal control processes and procedures to address significant changes to existing accounting policies and practices, including the need for dual record-keeping during 2011, and changes to financial systems Design and implement internal controls with respect to one-time changeover adjustments and related communications. For changes to accounting policies and practices identified, assess the DC&P and ICOFR design and effectiveness implications	Conduct management evaluation of new or revised controls throughout 2010 and 2011 Changes will be mapped and tested to ensure that no material deficiencies exist as a result of OPG's conversion to the IFRS accounting standards	An evaluation of OPG's readiness to transition to and report under IFRS positively concluded that the project controls are adequate to support the completion of tasks to adopt IFRS IFRS compliant accounting policies and procedures continue to be developed The impact on controls continues to be evaluated and changes are made where necessary IFRS opening balance sheet adjustment controls are being evaluated and are being applied to the January 1, 2011 opening transition balance sheet

RISK MANAGEMENT

A detailed discussion of OPG's governance structure and inherent risks is included in the 2010 annual MD&A under the heading, *Risk Management*. In addition, disclosure is provided relating to the activities that OPG undertakes to identify and manage these risks. This risk management update should be read in conjunction with the *Risk Management* section included in OPG's 2010 annual MD&A. The following discussion provides an update of OPG's risk management activities since the 2010 annual disclosure.

Operational Risks

Risks Associated with Major Development Projects

The risks associated with the cost, schedule and technical aspects of the major development projects could adversely impact OPG's financial performance and ultimately, its corporate reputation.

Niagara Tunnel Project

While the TBM mining has been completed, some costs and schedule uncertainty remains with respect to the liner installation. The factors that contribute to the uncertainty include the activities to restore and reinforce the tunnel profile, and the challenging logistics of concurrent construction operations. Allowances for these factors have been included in the cost estimate and schedule. The contractor has deployed additional resources to reinforce the initial tunnel liner and added concrete delivery methods to improve logistics, minimizing potential impact on the schedule for project completion.

Lower Mattagami Project

Construction of the Lower Mattagami River project commenced in June 2010. The last of the six new generating units associated with the project are scheduled to be in-service by June 2015. Differing site conditions in the form of significant geotechnical issues have been encountered at the Smoky Falls and Kipling sites. These conditions may have an impact on both the project cost and schedule. The total impact of these issues on the project schedule and potential cost implications are still being determined. In addition, key risks to the project costs and schedule include labour productivity on concrete pours during construction, and legal challenges or blockades by groups opposed to various aspects of the project. Risk mitigation activities include hiring an experienced contractor to construct the project, developing plans for a shelter to continue concrete operations during the winter, detailed monitoring of labour productivity, and providing allowances in the cost estimate and schedule.

Financial Risks

Commodity Markets

Changes in the market price of electricity or of the fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

OPG's revenue from its unregulated assets is also affected by changes in the market or spot price of electricity. The Company takes steps, such as executing forward sales at fixed prices, to mitigate the impact that extreme variations in the spot price could have on the gross margin.

The percentages of OPG's expected generation, emission requirements, and fuel requirements hedged are shown below. These amounts are based on yearly forecasts of generation and supply mix, and as such are subject to change as these forecasts are updated.

	2011[4]	**2012**	**2013**
Estimated generation output hedged [1]	81%	82%	81%
Estimated fuel requirements hedged [2]	75%	54%	51%
Estimated nitric oxide (NO) emission requirement hedged [3]	100%	100%	100%
Estimated sulphur dioxide (SO_2) emission requirement hedged [3]	100%	100%	100%

1 Represents the portion of megawatt hours of expected future generation production, including power purchases, for which the Company has sales commitments and contracts including the obligations under regulated pricing commitments, and agreements with the IESO, OEFC, and OPA.
2 Represents the approximate portion of megawatt hours of expected generation production (and thermal year end inventory targets) from each type of facility (thermal and nuclear) for which OPG has entered into contractual arrangements or obligations in order to secure the price of fuel. Excess fuel in inventories in a given year is attributed to the next year for the purpose of measuring hedge ratios.
3 Represents the approximate portion of megawatt hours of expected thermal production for which OPG has purchased, been allocated or granted emission allowances and Emission Reduction Credits to meet OPG's obligations under Ontario Environmental Regulations 397/01.
4 Includes forecast for the remainder of the year.

Foreign Exchange and Interest Rate Markets

OPG's earnings and cash flows can be impacted by movements in the United States dollar relative to the Canadian dollar and by prevailing interest rates on its short-term borrowings and investment programs.

The majority of OPG's existing debt is at fixed interest rates. Interest rate risk arises with the need to undertake new financing and with the potential addition of variable rate debt. The management of these risks is undertaken by using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated new financing. As at September 30, 2011, OPG had total interest rate swap contracts outstanding with a notional principal of $820 million.

Trading

OPG's financial performance could be adversely affected by its trading activities.

OPG's trading operations are closely monitored and total exposures are measured and reported to senior management on a daily basis. The metric used to measure the risk of this trading activity is known as "value at risk" or "VaR", which is defined as the potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. The VaR utilization ranged between nil and $0.5 million during the three months ended September 30, 2011 compared to $0.2 million and $0.3 million during the three months ended June 30, 2011.

Credit

Deterioration in counterparty credit and non-performance by suppliers can adversely impact OPG's earnings and cash flows from operations.

OPG manages its exposure to various suppliers or "counterparties" by evaluating the financial condition of all counterparties and ensuring that appropriate collateral or other forms of security are held by OPG. OPG's credit exposure relating to energy markets transactions as at September 30, 2011, was $362 million, including $337 million to the IESO. Over 80 percent of the remaining $25 million exposure related to investment grade counterparties.

Nuclear Waste Obligations

The cost estimates of nuclear waste obligations are based on assumptions such as station end of life dates and nuclear waste volumes that are inherently uncertain.

OPG is required by various rules and regulations to provide cost estimates associated with its nuclear waste management and decommissioning obligations. OPG is currently updating the cost estimates associated with its nuclear waste and decommissioning obligations. These cost estimates are being updated concurrently with an update to the Ontario Nuclear Funds Agreement ("ONFA") Reference Plan. OPG's costs for nuclear waste management and decommissioning, and its contribution obligations to the Nuclear Funds could significantly change as a result of updated cost estimates and the new ONFA Reference Plan.

Regulatory Risks

Rate Regulation

Significant uncertainties remain regarding the outcome of past and future rate proceedings, which determine the regulated prices for OPG's rate regulated operations.

The prices for electricity generated from most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that it operates are determined by the OEB, currently on a forecast cost of service methodology. As with any regulated price established using a forecast cost of service methodology, there is an inherent risk that the prices established by the regulator may not provide for recovery of all actual costs incurred by the regulated operations, or allow the regulated operations to earn the allowed rate of return.

In March 2011, the OEB issued its decision on OPG's application for new regulated prices for 2011 and 2012. In April 2011, OPG filed a notice of appeal with the Divisional Court of Ontario related to the part of the OEB's decision disallowing recovery in regulated prices of a portion of OPG's nuclear compensation costs. This matter was heard on October 18, 2011. The Court will be making its decision on this matter at a later date.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

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

QUARTERLY FINANCIAL HIGHLIGHTS

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

(millions of dollars – except where noted)	**September 30 2011**	**June 30 2011**	**March 31 2011**	**December 31 2010**
Revenue	**1,275**	1,226	1,308	1,324
Net (loss) income	**(96)**	114	151	202
Net (loss) income per share	**$(0.38)**	$0.45	$0.59	$0.79

(millions of dollars – except where noted)	**September 30 2010**	**June 30 2010**	**March 31 2010**	**December 31 2009**
Revenue	1,391	1,210	1,443	1,390
Net income (loss)	333	(29)	143	67
Net income (loss) per share	$1.29	$(0.11)	$0.56	$0.26

OPG's quarterly results are impacted by changes in demand primarily resulting from variations in seasonal weather conditions. Historically, OPG's revenues are higher in the first quarter of a fiscal year as a result of winter heating demands, and in the third quarter due to air conditioning and cooling demands.

Additional items which impacted net income (loss) in certain quarters above are described below and in OPG's 2010 annual MD&A under the heading, *Quarterly Financial Highlights*.

- A decrease in gross margin during the first quarter of 2011 primarily due to lower revenue recognized related to the energy supply contract for the Lennox generating station, cessation of additions to the Tax Loss Variance Account based on the OEB's 2011 decision and order effective March 1, 2011, and a decrease in thermal generation revenue, partially offset by a decrease in fuel and fuel related costs and higher revenue related to a contingency support agreement established with the OEFC for the Nanticoke and Lambton coal-fired generating stations, and higher nuclear generation revenue;
- An increase in pension and OPEB costs in 2011, largely as a result of lower discount rates in 2011; and
- In its June 2011 decision, the OEB established the Pension and OPEB Cost Variance Account effective March 1, 2011. As a result, during the second quarter of 2011, OPG recorded a regulatory asset of $41 million related to this variance account, resulting in reductions to OM&A expenses and income tax expense of $30 million and $11 million, respectively. The account is effective until December 31, 2012.

Additional information about OPG, including its Annual Information Form, annual MD&A, and audited annual consolidated financial statements and notes thereto for the year ended December 31, 2010 can be found on SEDAR at www.sedar.com.

SUPPLEMENTAL EARNINGS MEASURES

In addition to providing net income in accordance with Canadian GAAP, OPG's MD&A, unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2011 and 2010 and the notes thereto, present certain non-GAAP financial measures. These financial measures do not have standard definitions prescribed by Canadian GAAP, and therefore, may not be comparable to similar measures disclosed by other companies. OPG utilizes these measures in making operating decisions and assessing its performance. Readers of the MD&A, consolidated financial statements, and notes thereto, utilize these measures in assessing the Company's financial performance from on-going operations. These non-GAAP financial measures have not been presented as an alternative to net income in accordance with Canadian GAAP as an indicator of operating performance. The definitions of the non-GAAP financial measures are as follows:

(1) **Gross margin** is defined as revenue less fuel expense.

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

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www.opg.com www.sedar.com	Media Relations	416-592-4008

INTERIM CONSOLIDATED STATEMENTS OF (LOSS) INCOME (UNAUDITED)

(millions of dollars – except where noted)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2011	**2010**	**2011**	**2010**
Revenue *(Notes 2 and 13)*	**1,275**	1,391	**3,809**	4,044
Fuel expense *(Note 13)*	**217**	259	**566**	716
Gross margin *(Note 13)*	**1,058**	1,132	**3,243**	3,328
Expenses *(Note 13)*				
Operations, maintenance and administration	**628**	677	**2,026**	2,185
Depreciation and amortization *(Note 4)*	**197**	175	**550**	515
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)*	**177**	165	**526**	495
Losses (earnings) on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**16**	(287)	**(286)**	(468)
Property and capital taxes	**15**	20	**38**	63
Restructuring *(Note 16)*	**19**	-	**19**	25
	1,052	750	**2,873**	2,815
Income before the following:	**6**	382	**370**	513
Other (gains) losses *(Note 13)*	**(2)**	1	**(5)**	(1)
Income before interest and income taxes	**8**	381	**375**	514
Net interest expense	**39**	41	**121**	130
(Loss) income before income taxes	**(31)**	340	**254**	384
Income tax expense (recovery) *(Note 9)*				
Current	**17**	24	**113**	(77)
Future	**48**	(17)	**(28)**	14
	65	7	**85**	(63)
Net (loss) income	**(96)**	333	**169**	447
Basic and diluted (loss) income per common share *(dollars)*	**(0.38)**	1.29	**0.66**	1.74
Common shares outstanding *(millions)*	**256.3**	256.3	**256.3**	256.3

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(millions of dollars)	**Three Months Ended September 30 2011**	**Three Months Ended September 30 2010**	**Nine Months Ended September 30 2011**	**Nine Months Ended September 30 2010**
Operating activities				
Net (loss) income	**(96)**	333	**169**	447
Adjust for non-cash items:				
Depreciation and amortization *(Note 4)*	**197**	175	**550**	515
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)*	**177**	165	**526**	495
Losses (earnings) on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**16**	(287)	**(286)**	(468)
Pension and other post employment benefit costs *(Note 10)*	**108**	83	**338**	251
Future income taxes (recovery) and other accrued charges *(Note 9)*	**48**	(17)	**(51)**	(82)
Provision for restructuring (*Note 16)*	**19**	-	**19**	25
Mark-to-market on derivative instruments	**(15)**	7	**(1)**	41
Provision for used nuclear fuel and low and intermediate level waste	**16**	12	**39**	33
Regulatory assets and liabilities *(Note 5)*	**(4)**	(74)	**(96)**	(186)
Other	**4**	11	**5**	22
	470	408	**1,212**	1,093
Contributions to nuclear fixed asset removal and nuclear waste management funds	**(62)**	(63)	**(188)**	(200)
Expenditures on fixed asset removal and nuclear waste management *(Note 8)*	**(45)**	(36)	**(132)**	(136)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management	**15**	21	**42**	88
Contributions to pension funds	**(83)**	(68)	**(219)**	(205)
Expenditures on other post employment benefits and supplementary pension plans	**(21)**	(21)	**(64)**	(58)
Expenditures on restructuring *(Note 16)*	**-**	(3)	**(12)**	(3)
Net changes to other long-term assets and liabilities	**10**	12	**25**	(8)
Net changes in non-cash working capital balances *(Note 14)*	**147**	109	**329**	116
Cash flow provided by operating activities	**431**	359	**993**	687
Investing activities				
Investment in fixed and intangible assets	**(266)**	(261)	**(811)**	(665)
Net proceeds from sale of fixed assets	**-**	-	**7**	-
Cash flow used in investing activities	**(266)**	(261)	**(804)**	(665)
Financing activities				
Net increase (decrease) in short-term notes *(Note 7)*	**-**	115	**(155)**	115
Distribution to a third party on behalf of the shareholder *(Note 12)*	**(14)**	-	**(14)**	-
Issuance of long-term debt *(Note 6)*	**200**	465	**897**	1,110
Repayment of long-term debt *(Note 6)*	**(190)**	(439)	**(382)**	(976)
Cash flow (used in) provided by financing activities	**(4)**	141	**346**	249
Net increase in cash and cash equivalents	**161**	239	**535**	271
Cash and cash equivalents, beginning of period	**654**	103	**280**	71
Cash and cash equivalents, end of period	**815**	342	**815**	342

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**September 30 2011**	**December 31 2010**
Assets		
Current assets		
Cash and cash equivalents	**815**	280
Accounts receivable *(Note 3)*	**168**	270
Fuel inventory	**679**	734
Prepaid expenses	**28**	42
Income and capital taxes recoverable	**-**	65
Future income taxes *(Note 9)*	**88**	73
Materials and supplies	**80**	85
	1,858	1,549
Fixed assets *(Note 13)*		
Property, plant and equipment	**20,436**	19,654
Less: accumulated depreciation	**6,482**	6,099
	13,954	13,555
Intangible assets *(Note 13)*		
Intangible assets	**357**	345
Less: accumulated amortization	**309**	297
	48	48
Other long-term assets		
Deferred pension asset	**1,170**	1,146
Nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**11,562**	11,246
Long-term investments	**26**	30
Long-term materials and supplies	**387**	400
Regulatory assets *(Note 5)*	**1,468**	1,559
Long-term accounts receivable and other assets	**44**	44
	14,657	14,425
	30,517	29,577

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**September 30 2011**	**December 31 2010**
Liabilities		
Current liabilities		
Accounts payable and accrued charges	**736**	762
Income and capital taxes payable	**125**	-
Long-term debt due within one year *(Note 6)*	**412**	385
Short-term notes payable *(Note 7)*	**-**	155
Deferred revenue due within one year	**12**	12
	1,285	1,314
Long-term debt *(Note 6)*	**4,331**	3,843
Other long-term liabilities		
Fixed asset removal and nuclear waste management *(Note 8)*	**13,135**	12,704
Other post employment benefits and supplementary pension plans	**2,040**	1,908
Long-term accounts payable and accrued charges	**582**	525
Deferred revenue	**171**	152
Future income taxes *(Note 9)*	**634**	798
Regulatory liabilities *(Note 5)*	**172**	248
	16,734	16,335
Shareholder's equity		
Common shares	**5,126**	5,126
Retained earnings	**3,179**	3,024
Accumulated other comprehensive loss	**(142)**	(69)
Attributable to shareholder of Ontario Power Generation Inc.	**8,163**	8,081
Non-controlling interest *(Notes 2 and 15)*	**4**	4
	8,167	8,085
	30,517	29,577

Commitments and Contingencies *(Notes 6, 10, 11, and 12)*

See accompanying notes to the interim consolidated financial statements

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

Nine Months Ended September 30 *(millions of dollars)*	**2011**	**2010**
Common shares	**5,126**	5,126
Retained earnings		
Balance at beginning of period	**3,024**	2,375
Net income	**169**	447
Distribution to a third party on behalf of the shareholder *(Note 12)*	**(14)**	-
Balance at end of period	**3,179**	2,822
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of period	**(69)**	(24)
Other comprehensive loss for the period	**(73)**	(62)
Balance at end of period	**(142)**	(86)
Attributable to shareholder of Ontario Power Generation Inc.	**8,163**	7,862
Non-controlling interest *(Notes 2 and 15)*	**4**	4
	8,167	7,866

INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME (UNAUDITED)

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**
Net (loss) income	**(96)**	333	**169**	447
Other comprehensive loss, net of income taxes				
Net loss on derivatives designated as cash flow hedges[1]	**(64)**	(30)	**(78)**	(57)
Reclassification to income of losses (gains) on derivatives designated as cash flow hedges[2]	**2**	(1)	**5**	(5)
Other comprehensive loss for the period	**(62)**	(31)	**(73)**	(62)
Comprehensive (loss) income	**(158)**	(302)	**96**	385

[1] Net of income tax recoveries of $13 million and nil for the three months ended September 30, 2011 and 2010, respectively. For the nine months ended September 30, 2011 and 2010, net of income tax recoveries of $14 million and nil, respectively.

[2] Net of income tax recoveries of nil and $1 million for the three months ended September 30, 2011 and 2010, respectively. For the nine months ended September 30, 2011 and 2010, net of income tax recoveries of nil and $3 million, respectively.

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2011 AND 2010 (UNAUDITED)

1. BASIS OF PRESENTATION

These interim consolidated financial statements were prepared following the same accounting policies and methods as in the most recent annual consolidated financial statements, except as discussed in Note 2 to these interim consolidated financial statements, and are presented in Canadian dollars. These interim consolidated financial statements do not contain all the disclosures required by Canadian generally accepted accounting principles ("GAAP") for annual financial statements. Accordingly, these interim consolidated financial statements should be read in conjunction with the most recently prepared annual consolidated financial statements for the year ended December 31, 2010.

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

Certain of the 2010 comparative amounts have been reclassified from financial statements previously presented to conform to the 2011 consolidated financial statement presentation.

2. CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

Changes Applicable to the Current Period

Business Combinations, Consolidated Financial Statements, and Non-controlling Interests

Effective January 1, 2011, Ontario Power Generation Inc. ("OPG" or the "Company") adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 1582 *Business Combinations* ("Section 1582"), Section 1601 *Consolidated Financial Statements* ("Section 1601"), and Section 1602 *Non-controlling Interests* ("Section 1602"). Section 1582 specifies a number of changes, including an expanded definition of a business, a requirement to measure all business acquisitions at fair value, and a requirement to recognize acquisition-related costs as expenses. Section 1601 establishes the standards for preparing consolidated financial statements. Section 1602 specifies that non-controlling interests be treated as a separate component of equity, not as a liability or other item outside of equity. These new standards are harmonized with International Financial Reporting Standards ("IFRS"). These standards shall be applied prospectively to business combinations whose acquisition date is on or after the date of adoption. As a result of adopting Section 1602, the Company has reclassified its non-controlling interests as a separate component of equity. The adoption of Section 1582 and Section 1601 did not have a material impact on the Company's consolidated financial statements for the three and nine month periods ended September 30, 2011.

Revenue Recognition – Generating Assets

Effective March 1, 2011, energy revenue generated from the nuclear facilities owned and operated by OPG is based on a regulated price of 5.59¢/kWh pursuant to the decision and order issued by the Ontario Energy Board ("OEB") in March and April 2011, respectively. The nuclear regulated price includes a rate rider of 0.43¢/kWh for the recovery of approved nuclear variance and deferral account balances based on recovery periods authorized by the OEB. Effective March 1, 2011, generation from OPG's regulated hydroelectric facilities receives a regulated price of 3.41¢/kWh, pursuant to the OEB's decision and order. The hydroelectric regulated price is net of a negative rate rider of -0.17¢/kWh reflecting the repayment of the approved regulated hydroelectric variance account balances. These rate riders will remain in effect until December 31, 2012.

In its decision, the OEB also approved the continuation of the existing hydroelectric incentive mechanism ("HIM"), but determined that a portion of the resulting net revenues should be shared with ratepayers effective March 1, 2011. Prior to March 1, 2011, energy revenue generated from the nuclear facilities owned and operated by OPG was based on a regulated price of 5.50¢/kWh, including a rate rider of 0.20¢/kWh for the recovery of the approved nuclear variance and deferral account balances, pursuant to the OEB's 2008 decision. Pursuant to that decision, prior to March 1, 2011, the revenue from the regulated hydroelectric generation was based on a regulated price of 3.67¢/kWh, which included the recovery of the approved regulated hydroelectric variance account balances and was subject to the HIM.

Electricity generated from OPG's other generating assets remains unregulated and continues to receive the Ontario electricity spot market price, except where an energy supply or costs recovery agreement is in place.

Thermal Asset Retirement Obligation

Effective September 30, 2011, OPG reduced the asset retirement obligation ("ARO") estimate for most of its thermal generating stations by $4 million. The reduction reflected an increase in the expected cost recovery of station equipment and materials, partially offset by an increase in the demolition estimate. As a result of the ARO adjustment, OPG recorded a corresponding reduction to Property, Plant and Equipment in the Unregulated – Thermal business segment of $2 million and a net gain of $2 million. The gain has been recorded in the Thermal and Other segments consistent with the segment classification of the stations as other (gains) losses.

Future Changes in Accounting Policy

In February 2008, the Canadian Accounting Standards Board ("AcSB") confirmed that Publicly Accountable Enterprises will be required to transition from Canadian GAAP to IFRS, as issued by the International Accounting Standards Board, for interim and annual financial reporting purposes for fiscal years beginning on or after January 1, 2011. As a result of subsequent changes to Part I of the CICA Handbook – Accounting by the AcSB, certain rate-regulated entities can defer the adoption of IFRS by one year to January 1, 2012. OPG meets the AcSB's criteria for the deferral and has chosen to adopt IFRS effective January 1, 2012.

IFRS are premised on a conceptual framework similar to Canadian GAAP, however, significant differences exist in certain matters of recognition, measurement and disclosure. In line with OPG's IFRS conversion project, an assessment has been completed to identify the key accounting differences from Canadian GAAP. OPG's assessment of the impact of IFRS is based on the IFRS standards in effect at the time of conversion on January 1, 2012, and accounting elections made. Proposed changes to the IFRS accounting standards have the potential to introduce additional significant accounting differences. OPG's interim consolidated financial statements, as currently disclosed in accordance with Canadian GAAP, will be significantly different when presented in accordance with IFRS. OPG will publish its first consolidated financial statements prepared in accordance with IFRS for the three months ending and as at March 31, 2012, and for the corresponding comparative period. The opening balance sheet as at January 1, 2011, will be disclosed in the March 31, 2012 interim consolidated financial statements.

3. SALE OF ACCOUNTS RECEIVABLE

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

During 2010, in accordance with the receivable purchase agreement, OPG renewed the agreement with a maturity date of August 31, 2013 and a commitment of $250 million.

The accounts receivable reported and securitized by the Company are as follows:

(millions of dollars)	**Principal Amount of Receivables as at September 30 2011**	**Principal Amount of Receivables as at December 31 2010**
Total receivables portfolio [1]	**309**	377
Receivables sold	**250**	250
Receivables retained	**59**	127

[1] Amount represents receivables outstanding, including receivables that have been securitized, which the Company continues to service.

The pre-tax charges and average cost of funds are as follows:

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars – except where noted)	**2011**	**2010**	**2011**	**2010**
Pre-tax charges	**1**	1	**3**	3
Average cost of funds *(percent)*	**1.8**	1.8	**1.8**	1.4

4. DEPRECIATION AND AMORTIZATION

Depreciation and amortization expense for the three and nine month periods ended September 30, 2011 and 2010 consists of the following:

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**
Depreciation	**134**	145	**399**	427
Amortization of intangible assets	**3**	5	**11**	13
Amortization of regulatory assets and liabilities *(Note 5)*	**60**	25	**140**	75
	197	175	**550**	515

Interest capitalized to construction and development in progress at an average rate of five percent during the three and nine month periods ended September 30, 2011 (three and nine month periods ended September 30, 2010 – six percent) was $23 million and $61 million, respectively (three and nine month periods ended September 30, 2010 – $20 million and $56 million, respectively).

5. REGULATORY ASSETS AND LIABILITIES

The OEB's decisions issued in 2008 and 2009 authorized certain variance and deferral accounts, including those authorized pursuant to *Ontario Regulation 53/05*, a regulation under the *Ontario Energy Board Act, 1998*. During January and February 2011, the Company recorded additions to these variance and deferral accounts pursuant to the OEB's decisions.

In March 2011, the OEB issued its decision on OPG's application for new prices for OPG's regulated generation effective March 1, 2011. In that decision, the OEB approved OPG's request for the disposition of variance and deferral account balances as at December 31, 2010. The OEB also authorized the continuation of previously existing variance and deferral accounts, with the exception of the Nuclear Fuel Cost Variance Account, which was discontinued as of March 1, 2011. The OEB also established the Hydroelectric Surplus Baseload Generation Variance Account and the HIM Variance Account.

Effective March 1, 2011, the Company recorded additions to the variance and deferral accounts authorized by the OEB's March 2011 decision, and amortized approved regulatory balances based on recovery periods established by that decision.

In March 2011, OPG filed with the OEB a motion to review and vary the OEB's March 2011 decision with respect to pension and other post employment benefit ("OPEB") costs. In June 2011, the OEB established the Pension and OPEB Cost Variance Account in its decision and order granting OPG's motion. The variance account records the difference between actual pension and OPEB costs and related tax impacts and those reflected in the current regulated prices. The variance account is in effect for the period from March 1, 2011 to December 31, 2012. The balance in the account will be reviewed by the OEB as part of OPG's next application for regulated prices. During the three and nine month periods ended September 30, 2011, OPG recorded increases of $30 million and $71 million, respectively, to a regulatory asset related to the Pension and OPEB Cost Variance Account, resulting in a reduction to operations, maintenance and administration expenses of $23 million and $53 million, respectively, and a reduction to income tax expense of $7 million and $18 million, respectively.

OPG also recorded interest on outstanding balances in the variance and deferral accounts at the interest rate prescribed by the OEB, which was 1.47 percent per annum during the nine months ended September 30, 2011. The interest rate fluctuated in the range of 0.55 percent to 1.20 percent per annum during the year ended December 31, 2010.

In March 2011, OPG recorded a regulatory asset related to the amount of income taxes payable by the Company as a result of the OEB's approval for recovery of certain variance and deferral account balances in its March 2011 decision. The regulatory asset was based on the amount of income taxes expected to be recovered through current regulated prices and is amortized as these income taxes are recovered. During the three and nine month periods ended September 30, 2011, OPG recorded a reduction to income tax expense of nil and $57 million, respectively, and a charge of $8 million and $18 million, respectively, to depreciation and amortization expense related to this regulatory asset.

The regulatory assets and liabilities recorded as at September 30, 2011 and December 31, 2010 are as follows:

(millions of dollars)	**September 30 2011**	**December 31 2010**
Regulatory assets		
Future Income Taxes *(Note 9)*	**583**	711
Bruce Lease Net Revenues Variance Account	**261**	250
Tax Loss Variance Account	**455**	492
Current Income Taxes	**39**	-
Pension and OPEB Cost Variance Account	**71**	-
Other	**59**	106
Total regulatory assets	**1,468**	1,559
Regulatory liabilities		
Nuclear Development Variance Account	**74**	111
Hydroelectric Water Conditions Variance Account	**49**	70
Income and Other Taxes Variance Account	**37**	40
Other	**12**	27
Total regulatory liabilities	**172**	248

As at September 30, 2011 and December 31, 2010, other regulatory assets include the Nuclear Liability Deferral Account, the Pickering A Return to Service Deferral Account, the Nuclear Deferral and Variance Over/Under Variance Account, the Nuclear Fuel Cost Variance Account, and other regulatory asset balances. As at September 30, 2011 and December 31, 2010, other regulatory liabilities include the Hydroelectric Deferral and Variance Over/Under Variance Account, the Capacity Refurbishment Variance Account, and other regulatory liability balances.

The changes in the regulatory assets and liabilities during the nine months ended September 30, 2011 and the year ended December 31, 2010 are as follows:

(millions of dollars)	**Future Income Taxes**	**Bruce Lease Net Revenues Variance**	**Tax Loss Variance**	**Current Income Taxes**	**Pension and OPEB Cost Variance**	**Nuclear Develop-ment Variance**	**Hydro-electric Water Conditions Variance**	**Income and Other Taxes Variance**	**Other (net)**
Regulatory assets (liabilities), January 1, 2010	592	328	295	-	-	(55)	(55)	(21)	140
Change during the year	119	(81)	194	-	-	(50)	(14)	(19)	34
Interest	-	3	3	-	-	(1)	(1)	-	1
Amortization during the year	-	-	-	-	-	(5)	-	-	(96)
Regulatory assets (liabilities), December 31, 2010	711	250	492	-	-	(111)	(70)	(40)	79
Change during the period	(128)	88	33	57	71	3	(1)	(9)	5
Interest	-	2	5	-	-	(1)	-	-	-
Amortization during the period	-	(79)	(75)	(18)	-	35	22	12	(37)
Regulatory assets (liabilities), September 30, 2011	**583**	**261**	**455**	**39**	**71**	**(74)**	**(49)**	**(37)**	**47**

The following tables summarize the income statement and other comprehensive income statement impacts of recognizing regulatory assets and liabilities:

(millions of dollars)	Three Months Ended September 30, 2011 As Stated	Impact of Regulatory Assets and Liabilities	Financial Statements without the Impact of Regulatory Assets and Liabilities	Three Months Ended September 30, 2010 As Stated	Impact of Regulatory Assets and Liabilities	Financial Statements without the Impact of Regulatory Assets and Liabilities
Revenue	**1,275**	**10**	**1,285**	1,391	(64)	1,327
Fuel expense	**217**	**7**	**224**	259	19	278
Operations, maintenance and administration	**628**	**32**	**660**	677	(12)	665
Depreciation and amortization	**197**	**(60)**	**137**	175	(33)	142
Accretion on fixed asset removal and nuclear waste management liabilities	**177**	**(1)**	**176**	165	3	168
Losses (earnings) on nuclear fixed asset removal and nuclear waste management funds	**16**	**143**	**159**	(287)	(150)	(437)
Property and capital taxes	**15**	**-**	**15**	20	(6)	14
Net interest expense	**39**	**2**	**41**	41	-	41
Income tax expense (recovery)	**65**	**(95)**	**(30)**	7	112	119
Other comprehensive loss	**(62)**	**7**	**(55)**	(31)	9	(22)

(millions of dollars)	Nine Months Ended September 30, 2011 As Stated	Impact of Regulatory Assets and Liabilities	Financial Statements without the Impact of Regulatory Assets and Liabilities	Nine Months Ended September 30, 2010 As Stated	Impact of Regulatory Assets and Liabilities	Financial Statements without the Impact of Regulatory Assets and Liabilities
Revenue	**3,809**	**(33)**	**3,776**	4,044	(211)	3,833
Fuel expense	**566**	**11**	**577**	716	29	745
Operations, maintenance and administration	**2,026**	**57**	**2,083**	2,185	(49)	2,136
Depreciation and amortization	**550**	**(146)**	**404**	515	(98)	417
Accretion on fixed asset removal and nuclear waste management liabilities	**526**	**2**	**528**	495	9	504
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(286)**	**116**	**(170)**	(468)	(97)	(565)
Property and capital taxes	**38**	**(4)**	**34**	63	(12)	51
Net interest expense	**121**	**5**	**126**	130	(2)	128
Income tax expense (recovery)	**85**	**(79)**	**6**	(63)	99	36
Other comprehensive loss	**(73)**	**10**	**(63)**	(62)	18	(44)

6. LONG-TERM DEBT

Long-term debt consists of the following:

(millions of dollars)	September 30 2011	December 31 2010
Notes payable to the Ontario Electricity Financial Corporation	**3,915**	3,865
UMH Energy Partnership debt	**198**	198
Lower Mattagami Energy Limited Partnership debt	**471**	-
Share of non-recourse limited partnership debt	**159**	165
	4,743	4,228
Less: due within one year		
Notes payable to the Ontario Electricity Financial Corporation	**400**	375
UMH Energy Partnership debt	**3**	2
Share of non-recourse limited partnership debt	**9**	8
	412	385
Long-term debt	**4,331**	3,843

Interest paid during the three months ended September 30, 2011 was $87 million (three months ended September 30, 2010 – $88 million), of which $86 million related to interest paid on long-term debt (three months ended September 30, 2010 – $86 million). Interest paid during the nine months ended

September 30, 2011 was $210 million (nine months ended September 30, 2010 – $216 million), of which $204 million related to interest paid on long-term debt (nine months ended September 30, 2010 – $209 million). Interest on the notes payable to the Ontario Electricity Financial Corporation ("OEFC") is paid semi-annually.

During 2010, OPG executed an amended Niagara Tunnel project credit facility for an amount up to $1.6 billion. As at September 30, 2011, advances under this facility were $815 million (December 31, 2010 – $690 million), which included $50 million of new borrowing during the third quarter of 2011.

OPG reached an agreement with the OEFC in the first quarter of 2011 for a $375 million credit facility to refinance notes as they mature over the period from January 2011 to December 2011. Refinancing under this agreement totalled $300 million as at September 30, 2011, which included $150 million of new borrowing during the third quarter of 2011.

On May 17, 2011, senior notes totalling $475 million were issued by the Lower Mattagami Energy Limited Partnership ("LME"). The senior notes have interest rates of 4.3 percent for notes of $225 million maturing in 2021 and 5.1 percent for notes of $250 million maturing in 2041. On October 25, 2011, senior notes totalling $96 million were issued by the LME. These senior notes have an interest rate of 2.6 percent and mature in 2015. These notes are secured by the assets of the Lower Mattagami project including existing operating facilities and facilities being constructed.

7. SHORT-TERM CREDIT FACILITIES

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year tranches. In May 2011, OPG renewed and extended one $500 million tranche to May 18, 2015. The other $500 million tranche has a maturity date of May 20, 2013. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. As at September 30, 2011, no commercial paper was outstanding (December 31, 2010 – nil). OPG had no other outstanding borrowings under the bank credit facility as at September 30, 2011 and December 31, 2010.

During 2010, the LME established a $700 million bank credit facility to support the initial construction phase for the Lower Mattagami project and launched a commercial paper program. In July 2011, OPG extended the maturity date of this credit facility to August 7, 2015. As at September 30, 2011, no commercial paper was outstanding under this program (December 31, 2010 – $155 million). In March 2011, OPG executed a $700 million credit facility with the OEFC in support of the Lower Mattagami project. As at September 30, 2011, there was no outstanding borrowing under this credit facility.

8. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT

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

(millions of dollars)	**September 30 2011**	**December 31 2010**
Liability for nuclear used fuel management	**7,819**	7,534
Liability for nuclear decommissioning and low and intermediate level waste management	**5,158**	5,013
Liability for non-nuclear fixed asset removal	**158**	157
Fixed asset removal and nuclear waste management liabilities	**13,135**	12,704

The changes in the fixed asset removal and nuclear waste management liabilities for the nine months ended September 30, 2011 and the year ended December 31, 2010 are as follows:

(millions of dollars)	**September 30 2011**	**December 31 2010**
Liabilities, beginning of period	**12,704**	11,859
Increase in liabilities due to accretion	**528**	673
Increase in liabilities due to changes in assumptions related to the decision to commence the definition phase of the refurbishment of the Darlington nuclear generating station	**-**	293
Increase in liabilities due to nuclear used fuel, nuclear waste management variable expenses and other expenses	**39**	56
Liabilities settled by expenditures on fixed asset removal and waste management	**(132)**	(181)
Change in the liabilities for non-nuclear fixed asset removal *(Note 2)*	**(4)**	4
Liabilities, end of period	**13,135**	12,704

The cash and cash equivalents balance as at September 30, 2011 includes $3 million of cash and cash equivalents that are for the use of nuclear waste management activities (December 31, 2010 – $3 million).

Ontario Nuclear Funds Agreement

OPG sets aside and invests funds held in segregated custodian and trustee accounts specifically for discharging its nuclear fixed asset removal and nuclear waste management liabilities in accordance with the Ontario Nuclear Funds Agreement (“ONFA”) and the federal Nuclear Fuel Waste Act (“NFWA”).

The nuclear fixed asset removal and nuclear waste management funds (“Nuclear Funds”) as at September 30, 2011 and December 31, 2010 consist of the following:

(millions of dollars)	**Fair Value** **September 30 2011**	**December 31 2010**
Decommissioning Segregated Fund	**5,147**	5,267
Used Fuel Segregated Fund[1]	**6,230**	6,198
Due from (to) Province – Used Fuel Segregated Fund	**185**	(219)
	6,415	5,979
	11,562	11,246

[1] The Ontario NFWA Trust represented $2,244 million as at September 30, 2011 (December 31, 2010 – $1,949 million) of the Used Fuel Segregated Fund on a fair value basis.

As required by the terms of the ONFA, the Province of Ontario (“Province”) has provided a Provincial Guarantee to the Canadian Nuclear Safety Commission (“CNSC”) since 2003, on behalf of OPG. The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The Provincial Guarantee provides for any shortfall between the long-term liabilities and the current market value of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund, up to the value of the Provincial Guarantee. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount of the Provincial Guarantee provided by the Province. In December 2009, the CNSC approved an increase in the amount of the Provincial Guarantee to $1,545 million effective on March 1, 2010. The value of this Provincial Guarantee will be in effect through to the end of 2012, when the next reference plan for the CNSC is planned to be approved. In January 2011, OPG paid a guarantee fee of $8 million based on a Provincial Guarantee amount of $1,545 million. OPG is planning preliminary discussions with the CNSC on the process for submitting the required documentation for the 2013–2017 Reference Plan.

In accordance with CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement* (“Section 3855”), the investments in the Nuclear Funds and the corresponding receivables from and payables to the Province are classified as held-for-trading and are measured at fair value with realized and unrealized gains and losses recognized in OPG’s interim consolidated financial statements.

The (losses) earnings on the Nuclear Funds for the three and nine month periods ended September 30, 2011 and 2010 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**
Decommissioning Segregated Fund	**(227)**	323	**(98)**	284
Used Fuel Segregated Fund	**68**	114	**268**	281
Bruce Lease Net Revenues Variance Account *(Note 5)*	**143**	(150)	**116**	(97)
Total (losses) earnings	**(16)**	287	**286**	468

9. INCOME TAXES

OPG follows the liability method of tax accounting for all its business segments and records a corresponding regulatory asset or liability for the future income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

During the three months ended September 30, 2011, OPG recorded a decrease of $75 million to the future income tax liability for the future taxes relating to the regulated operations. Since these future income taxes are expected to be refunded through future regulated prices, OPG has recorded a corresponding decrease to the regulatory asset for future income taxes. As a result, the future income taxes for the three months ended September 30, 2011 were not impacted.

During the nine months ended September 30, 2011, OPG recorded a decrease of $128 million to the future income tax liability for the future taxes relating to the regulated operations. Since these future income taxes are expected to be refunded through future regulated prices, OPG has recorded a corresponding decrease to the regulatory asset for future income taxes. As a result, the future income taxes for the nine months ended September 30, 2011 were not impacted.

The amount of cash income taxes paid during the three months ended September 30, 2011 was nil (three months ended September 30, 2010 – nil). For the nine months ended September 30, 2011, income taxes paid were nil (nine months ended September 30, 2010 – $33 million).

10. PENSION AND OTHER POST EMPLOYMENT BENEFIT COSTS

Total benefit costs for the three and nine month periods ended September 30, 2011 and 2010 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**
Registered pension plans	**66**	31	**195**	94
Supplementary pension plans	**6**	5	**18**	15
Other post employment benefits	**59**	47	**178**	142
Pension and OPEB Cost Variance Account *(Note 5)*	**(23)**	-	**(53)**	-
Pension and other post employment benefit costs	**108**	83	**338**	251

An actuarial valuation of the OPG registered pension plan was completed as of January 1, 2011. Based on the actuarial valuation, OPG will increase its annual contribution to the plan from $270 million in 2010 to $300 million in 2011. The annual contributions for 2012 and 2013 will be adjusted for changes in current service costs in each year. OPG will continue to assess the requirements for contributions to the pension plan. The next actuarial valuation for funding purposes must have an effective date no later than January 1, 2014.

11. Financial Instruments

The Risk Oversight Committee ("ROC") assists the Board of Directors to fulfill its oversight responsibilities for matters relating to identification and management of the Company's key business risks. Risk management activities are coordinated by a centralized Corporate Risk Management group led by the Chief Risk Officer. Risks that would prevent business units from achieving business plan objectives are identified at the business unit level. Senior management sets risk limits for the financing, procurement, and trading activities of the Company and ensures that effective risk management policies and processes are in place to ensure compliance with such limits in order to maintain an appropriate balance between risk and return. OPG's risk management process aims to continually evaluate the effectiveness of risk mitigation activities for identified key risks. The findings from this evaluation process are reported quarterly to the ROC.

OPG is exposed to risks related to changes in electricity prices associated with a wholesale spot market for electricity in Ontario, changes in interest rates, and movements in foreign currency that affect its assets, liabilities, and forecast transactions. Select derivative instruments are used to limit such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Derivatives and Hedging

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

Hedge accounting is applied when the derivative instrument is designated as a hedge and is expected to be effective throughout the life of the hedged item. When such a derivative instrument hedge ceases to be effective as a hedge, or when designation of a hedging relationship is terminated, any associated deferred gains or losses are recognized in income in the current period. When a hedged item ceases to exist, any associated deferred gains or losses are recognized in the current period's consolidated statement of income.

Derivative Instruments Qualifying for Hedge Accounting

The following table provides the estimated fair value of derivative instruments designated as hedges.

(millions of dollars – except where noted)	**Notional Quantity**	**Terms**	**Fair Value**	**Notional Quantity**	**Terms**	**Fair Value**
	September 30, 2011			**December 31, 2010**		
Floating-to-fixed interest rate hedges	**32**	**1–8 yrs**	**(4)**	35	1–9 yrs	(4)
Forward start interest rate hedges	**820**	**1–13 yrs**	**(98)**	375	1–12 yrs	(21)

OPG has entered into a number of forward start interest rate swap agreements to hedge against the effect of changes in interest rates for long-term debt for the Niagara Tunnel. In the second and third quarter of 2011, the LME entered into forward start interest rate swaps to hedge against the effect of future changes in interest rates for long-term debt for the Lower Mattagami project.

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

Net losses of $2 million and $5 million, which include the impact of income taxes, related to derivative instruments qualifying for hedge accounting, were recognized in net income during the three and nine months ended September 30, 2011, respectively. Existing net losses of $6 million deferred in accumulated other comprehensive loss at September 30, 2011 are expected to be reclassified to net income within the next 12 months.

Derivative Instruments Not Qualifying for Hedge Accounting

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

(millions of dollars – except where noted)	**Notional Quantity**	**Fair Value**	**Notional Quantity**	**Fair Value**
	September 30, 2011		**December 31, 2010**	
Commodity derivative instruments				
Assets	**2.4 TWh**	**5**	1.7 TWh	3
Liabilities	**0.8 TWh**	**(1)**	0.1 TWh	-
Total		**4**		3

Under the Bruce Power lease agreement, lease revenue is reduced in each calendar year where the annual arithmetic average of the Hourly Ontario Electricity Price ("Average HOEP") falls below $30/MWh, and if certain other conditions are met. The conditional reduction to revenue included in the lease agreement is treated as a derivative according to Section 3855. OPG reported a liability of $164 million as at September 30, 2011 (December 31, 2010 – $163 million), which reflected the fair value of a derivative embedded in the Bruce Power lease agreement. This marginal increase in the fair value of the derivative liability was primarily due to reductions in the expected future Average HOEP since the beginning of 2011. The income statement impact resulting from the changes to the liability is offset by the income statement impact of the Bruce Lease Net Revenues Variance Account.

Fair Value

Fair value is the value that a financial instrument can be closed out or sold, in an arm's length transaction with a willing and knowledgeable counterparty. The fair value of financial instruments traded in active markets is based on quoted market prices at the interim consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's length basis. The quoted market price used for financial assets held by OPG is the bid price.

For financial instruments which do not have quoted market prices directly available, fair values are estimated using forward price curves developed from observable market prices or rates which may include the use of valuation techniques or models based, wherever possible, on assumptions supported by observable market prices or rates prevailing at the dates of the interim consolidated balance sheets. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate.

12. COMMITMENTS AND CONTINGENCIES

Litigation

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

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served on OPG and Bruce Power L.P. by British Energy Limited and British Energy International Holdings Limited (together "British Energy"). The British Energy claim against OPG pertains to corrosion in the Bruce Unit 8 Steam Generators, in particular, erosion of the support plates through which the boiler tubes pass. The claim amount includes $65 million due to an extended outage to repair some of the alleged damage. The balance of the amount claimed is based on an increased probability the steam generators will have to be replaced or the unit taken out of service prematurely. OPG leased the Bruce nuclear generating stations to Bruce Power L.P. in 2001.

British Energy is involved in arbitration with the current owners of Bruce Power L.P. regarding an alleged breach of British Energy's representations and warranties to the current owners when they purchased British Energy's interest in Bruce Power L.P. (the "Arbitration"). If British Energy is successful in defending against the Arbitration claim, they will not have suffered any damages to attempt to recoup from OPG. This Arbitration commenced on April 5, 2010. The Arbitration closing arguments were completed in the third quarter of 2011. It may take some time for the arbitrator to come to a decision after the completion of the closing arguments.

British Energy previously indicated that they did not require OPG or Bruce Power L.P. to actively defend the court action until the conclusion of the Arbitration. Although the Arbitration had not concluded, British Energy requested that OPG file a Statement of Defence. OPG and Bruce Power L.P. advised British Energy that if British Energy wishes the court action to proceed prior to the conclusion of the Arbitration, the defendants would bring a motion for a Stay of proceedings, a Dismissal of the current action or, in the alternative, a motion to extend the time for service of the Statement of Defence until the conclusion of the Arbitration. That motion was scheduled to be heard on March 5, 2010 but was adjourned at the request of British Energy. The return date of that motion is yet to be set.

During the third quarter of 2011, OPG settled a claim and arbitration with a certain First Nation in one settlement agreement. OPG was directed by its shareholder to pay a part of the shareholder's portion of the settlement liability on its behalf. As a result, OPG recorded a distribution of $14 million to the First Nation, which was recorded as a reduction to retained earnings in the third quarter of 2011. This settlement did not have a material impact on the Company's financial position.

Certain other First Nations have commenced actions against OPG for interference with their respective reserve and traditional land rights. As well, OPG has been brought into certain actions by the First Nations against other parties as a third party defendant. Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its financial position.

Environmental

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

13. BUSINESS SEGMENTS

Segment Income (Loss) for the Three Months Ended September 30, 2011 *(millions of dollars)*	**Regulated**			**Unregulated**				
	Nuclear Generation	**Nuclear Waste Manage-ment**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Elimination**	**Total**
Revenue	**794**	**18**	**176**	**94**	**171**	**39**	**(17)**	**1,275**
Fuel expense	**66**	**-**	**71**	**13**	**67**	**-**	**-**	**217**
Gross margin	**728**	**18**	**105**	**81**	**104**	**39**	**(17)**	**1,058**
Operations, maintenance and administration	**441**	**19**	**25**	**60**	**96**	**4**	**(17)**	**628**
Depreciation and amortization	**135**	**-**	**8**	**20**	**21**	**13**	**-**	**197**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**175**	**-**	**-**	**2**	**-**	**-**	**177**
Losses on nuclear fixed asset removal and nuclear waste management funds	**-**	**16**	**-**	**-**	**-**	**-**	**-**	**16**
Property and capital taxes (recovery)	**6**	**-**	**(1)**	**3**	**4**	**3**	**-**	**15**
Restructuring	**-**	**-**	**-**	**-**	**19**	**-**	**-**	**19**
Other losses (gains)	**-**	**-**	**-**	**-**	**18**	**(20)**	**-**	**(2)**
Income (loss) before interest and income taxes	**146**	**(192)**	**73**	**(2)**	**(56)**	**39**	**-**	**8**

Segment Income (Loss) for the Three Months Ended September 30, 2010 *(millions of dollars)*	Regulated			Unregulated				
	Nuclear Generation	**Nuclear Waste Manage-ment**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Elimination**	**Total**
Revenue	784	12	180	107	279	41	(12)	1,391
Fuel expense	43	-	63	10	143	-	-	259
Gross margin	741	12	117	97	136	41	(12)	1,132
Operations, maintenance and administration	478	14	23	64	106	4	(12)	677
Depreciation and amortization	98	-	16	18	29	14	-	175
Accretion on fixed asset removal and nuclear waste management liabilities	-	163	-	-	2	-	-	165
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(287)	-	-	-	-	-	(287)
Property and capital taxes	10	-	3	-	4	3	-	20
Other losses	-	-	-	-	-	1	-	1
Income (loss) before interest and income taxes	155	122	75	15	(5)	19	-	381

Segment Income (Loss) for the Nine Months Ended September 30, 2011 *(millions of dollars)*	Regulated			Unregulated				
	Nuclear Generation	Nuclear Waste Manage-ment	Hydro-electric	Hydro-electric	Thermal	Other	Elimination	Total
Revenue	**2,295**	**42**	**550**	**392**	**451**	**119**	**(40)**	**3,809**
Fuel expense	**179**	**-**	**190**	**55**	**142**	**-**	**-**	**566**
Gross margin	**2,116**	**42**	**360**	**337**	**309**	**119**	**(40)**	**3,243**
Operations, maintenance and administration	**1,461**	**47**	**76**	**168**	**298**	**16**	**(40)**	**2,026**
Depreciation and amortization	**363**	**-**	**30**	**56**	**64**	**37**	**-**	**550**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**521**	**-**	**-**	**5**	**-**	**-**	**526**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(286)**	**-**	**-**	**-**	**-**	**-**	**(286)**
Property and capital taxes (recovery)	**20**	**-**	**(2)**	**-**	**12**	**8**	**-**	**38**
Restructuring	**-**	**-**	**-**	**-**	**19**	**-**	**-**	**19**
Other (gains) losses	**(3)**	**-**	**-**	**-**	**19**	**(21)**	**-**	**(5)**
Income (loss) before interest and income taxes	**275**	**(240)**	**256**	**113**	**(108)**	**79**	**-**	**375**

Segment Income (Loss) for the Nine Months Ended September 30, 2010 *(millions of dollars)*	Regulated			Unregulated				
	Nuclear Generation	**Nuclear Waste Manage-ment**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Elimination**	**Total**
Revenue	2,234	33	548	359	780	122	(32)	4,044
Fuel expense	135	-	176	42	363	-	-	716
Gross margin	2,099	33	372	317	417	122	(32)	3,328
Operations, maintenance and administration	1,598	38	70	165	335	11	(32)	2,185
Depreciation and amortization	291	-	48	49	83	44	-	515
Accretion on fixed asset removal and nuclear waste management liabilities	-	490	-	-	5	-	-	495
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(468)	-	-	-	-	-	(468)
Property and capital taxes	32	-	8	3	9	11	-	63
Restructuring	-	-	-	-	25	-	-	25
Other gains	-	-	-	-	-	(1)	-	(1)
Income (loss) before interest and income taxes	178	(27)	246	100	(40)	57	-	514

(millions of dollars)	Nuclear	Regulated Hydro-electric	Unregulated Hydro-electric	Thermal	Other	Total
Selected Balance Sheet Information						
As at September 30, 2011						
Segment fixed assets in service, net	**3,850**	**3,752**	**3,297**	**220**	**737**	**11,856**
Segment construction in progress	**248**	**1,100**	**720**	**18**	**12**	**2,098**
Segment property, plant and equipment, net	**4,098**	**4,852**	**4,017**	**238**	**749**	**13,954**
As at September 30, 2011						
Segment intangible assets in service, net	**13**	**-**	**1**	**5**	**15**	**34**
Segment development in progress	**7**	**-**	**-**	**-**	**7**	**14**
Segment intangible assets, net	**20**	**-**	**1**	**5**	**22**	**48**
As at December 31, 2010						
Segment fixed assets in service, net	3,963	3,750	3,324	282	759	12,078
Segment construction in progress	174	913	367	20	3	1,477
Segment property, plant and equipment, net	4,137	4,663	3,691	302	762	13,555
As at December 31, 2010						
Segment intangible assets in service, net	18	-	5	1	16	40
Segment development in progress	3	-	-	-	5	8
Segment intangible assets, net	21	-	5	1	21	48

14. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	Three Months Ended September 30 2011	Three Months Ended September 30 2010	Nine Months Ended September 30 2011	Nine Months Ended September 30 2010
Accounts receivable	**64**	22	**104**	195
Prepaid expenses	**8**	(6)	**14**	(23)
Fuel inventory	**40**	38	**55**	127
Materials and supplies	**(1)**	-	**5**	38
Accounts payable and accrued charges	**(1)**	25	**(39)**	(201)
Income and capital taxes payable/recoverable	**37**	30	**190**	(20)
	147	109	**329**	116

15. NON-CONTROLLING INTEREST

OPG has entered into a partnership agreement with the Lac Seul First Nation ("LSFN") regarding the 12.5 MW Lac Seul generating station. In July 2009, OPG transferred ownership of the station to the Lac Seul LP partnership.

OPG consolidates the results of the Lac Seul LP and the non-controlling interest represents the LSFN's ownership interest in the partnership.

16. RESTRUCTURING

In September 2009, together with the Ministry of Energy and Infrastructure, OPG announced its decision to close two coal-fired units at each of the Lambton and Nanticoke coal-fired generating stations. The closures occurred on October 1, 2010. OPG conducted discussions with key stakeholders, including the Society of Energy Professionals and the Power Workers' Union, in accordance with their respective collective bargaining agreements. As determined by the collective bargaining agreements, restructuring costs of $27 million were recorded during 2010 for those employees who have elected to leave.

In addition, Ontario's Long-Term Energy Plan released in November 2010 and the Supply Mix Directive issued in February 2011 require the safe shutdown of two additional coal-fired units at the Nanticoke coal-fired generating station in 2011. On March 25, 2011, OPG notified key stakeholders of the decision in accordance with their respective collective bargaining agreements. In the third quarter of 2011, OPG recognized $19 million of restructuring costs associated with the unit closures. Additional restructuring costs are estimated to be $3 million and are expected to be recorded in 2012.

The change in the restructuring liability for severance costs for the nine months ended September 30, 2011 and for the year ended December 31, 2010 is as follows:

(millions of dollars)	
Liability, January 1, 2010	-
Restructuring charges during the year	27
Payments during the year	(12)
Liability, December 31, 2010	15
Restructuring charges during the period	19
Payments during the period	(12)
Liability, September 30, 2011	**22**

17. SEASONAL OPERATIONS

OPG's quarterly results are impacted by changes in demand resulting from variations in seasonal weather conditions. Primarily during the first and third quarters of a fiscal year, OPG's revenues are impacted as a result of winter heating demands in the first quarter and air conditioning/cooling demands in the third quarter. Regulated prices for most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that OPG operates, the contingency support agreement with the OEFC, and OPG's hedging strategies significantly reduced the impact of seasonal price fluctuations on the results of operations.