ONTARIOPOWER GENERATION

News
from Ontario Power Generation

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ONTARIO POWER GENERATION REPORTS 2014 SECOND QUARTER FINANCIAL RESULTS

[Toronto]: – Ontario Power Generation Inc. (OPG or Company) today reported its financial and operating results for the three and six months ended June 30, 2014. Net income attributable to the Province for the second quarter of 2014 was $115 million compared to $73 million for the same quarter in 2013. Net income attributable to the Province for the six months ended June 30, 2014 was $357 million compared to $101 million for the same period in 2013.

Tom Mitchell, President and CEO said, “OPG continues efforts to hold down our costs. By 2016, we plan to have saved an estimated $1 billion by reducing the overall headcount from ongoing operations by 20 per cent from 2011 levels, primarily through attrition. To date, the departure of 1,900 people since January 2011 has already saved $400 million. At the same time, we continue to reinvest in our facilities to ensure future reliability and value for the people of Ontario. OPG continues to generate electricity at a lower price than the average of all other electricity generators.”

Mr. Mitchell added, “OPG has successfully closed Ontario’s coal facilities without any disruption to the safety or reliability of our operations, which generate more than half of Ontario’s electricity. This delivers the government’s commitment to cleaner air and represents North America’s single largest greenhouse gas reduction initiative to-date. OPG’s generation is now almost one hundred per cent free of greenhouse gas and smog causing emissions.”

Net income attributable to the Province for the second quarter of 2014 increased by $42 million compared to the same quarter in 2013. The increase was primarily due to higher earnings from the Used Fuel Segregated Fund (Used Fuel Fund), and higher revenue as a result of increased production from generating stations included in the Lower Mattagami River project. The increase in earnings was also due to lower income tax expense. These increases were partially offset by an increase in outage expenditures.

Net income attributable to the Province for the six months ended June 30, 2014 increased by $256 million compared to the same period in 2013. This increase was primarily due to increased revenue as a result of higher electricity spot market prices and trading revenue as a result of unseasonably cold weather during the first quarter in 2014. The improvement was also due to higher earnings from the Used Fuel Fund, and higher generation revenue from generating stations included in the Lower Mattagami River project and the Thunder Bay generating station (GS).

Business Segment, Generating, and Operating Performance

OPG's income before interest and income taxes from the electricity generation business segments was $100 million in the second quarter of 2014, compared to $118 million in the same quarter of 2013. The decrease was a result of lower earnings from OPG's regulated segments, primarily due to higher Operations, maintenance and administration expenses related to planned outage activities. The decrease from the regulated segments was partially offset by higher earnings from the Contracted Generation Portfolio segment.

OPG's income before interest and income taxes from the electricity generation business segments was $446 million for the six months ended June 30, 2014, compared to $227 million for the same period of 2013. The increase was primarily due to higher hydroelectric generation revenue as a result of higher electricity spot market prices received for the generation produced by the 48 hydroelectric generating stations that have been prescribed for rate regulation effective July 1, 2014.

The improved earnings for the Regulated – Nuclear Waste Management business segment of $39 million in the second quarter of 2014 and $68 million for the first half of 2014 was primarily due to higher earnings on the Used Fuel Fund.

The increase in income before interest and income taxes of $10 million for the Services, Trading, and other Non-Generation business segment for the first half of 2014 was primarily a result of higher trading margin for electricity sold to neighbouring energy markets.

Total electricity generated during the three months ended June 30, 2014 was 19.8 terawatt hours (TWh), compared to 20.0 TWh for the same quarter in 2013. This decrease was mainly due to lower generation from the hydroelectric stations prescribed for rate regulation effective July 1, 2014. Total electricity generated during the six months ended June 30, 2014 was 40.3 TWh, compared to 41.3 TWh for the same period in 2013. This decrease was mainly due to lower generation from the Contracted Generation Portfolio segment and lower production from the hydroelectric stations subject to rate regulation effective July 1, 2014.

For the three months ended June 30, 2014 the capability factor at the Darlington Nuclear GS was 77.6 per cent compared to 85.9 per cent for the same quarter in 2013. The decrease was primarily due to an increase in planned outage days. For the six months ended June 30, 2014, the capability factor increased to 86.7 per cent compared to 85.0 per cent for the same period in 2013 due to a decrease in unplanned outage days for the first six months of the year. At the Pickering Nuclear GS, the capability factor improved to 77.4 per cent for the three months ended June 30, 2014, compared to 65.9 per cent in the same quarter of 2013 due to a decrease in the number of planned outage days. The capability factor at the Pickering Nuclear GS of 72.0 per cent for the six months ended June 30, 2014 was essentially unchanged compared to 72.4 per cent for the same period in 2013.

The availability of OPG's hydroelectric generating stations in the Contracted Generation Portfolio segment for the three and six month periods ended June 30, 2014 decreased primarily due to unplanned outages.

Generation Development

OPG is undertaking a number of generation development and life extension projects to support Ontario's long-term electricity supply requirements. Significant developments during the second quarter of 2014 are as follows:

Darlington Refurbishment

- The Darlington Refurbishment project is currently in the definition phase. A detailed cost and schedule estimate for the refurbishment of the four units is expected to be completed in 2015.
- There are 19 pre-requisite projects currently underway at Darlington that are to be completed in advance of the execution phase. A small number of these projects are experiencing execution challenges that have resulted in cost and schedule changes for those projects. This is not expected to alter the overall cost and schedule of the Darlington Refurbishment project. Early in 2014, in response to these challenges, OPG began implementing corrective actions such as new collaborative planning processes with vendors, dedicating resident engineers in vendor offices, exercising contract audit rights, and negotiating contract amendments.
- The cost variances relating to the impacted projects are estimated to be 2 to 3 per cent of the Darlington Refurbishment project's total $10 billion high confidence estimate in 2013 dollars, excluding capitalized interest and escalation. OPG remains confident that the cost of the refurbishment project will remain less than the high confidence estimate.

Lower Mattagami

- The Lower Mattagami River project is expected to be completed on schedule by June 2015 and within the approved budget of $2.6 billion. The 78 MW incremental unit at Harmon GS was declared in-service on June 3, 2014, ahead of its original target completion date of September 2014. This is the second incremental unit to be completed on the Lower Mattagami River project, as the incremental unit at the Little Long GS was declared in-service in the first quarter of 2014. In addition, the first 89 MW incremental unit at the Smoky Falls GS is expected to be declared in-service ahead of its original target completion date of November 2014. As incremental units are placed in-service, the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, may acquire up to a 25 per cent interest in the assets through its investment in the Lower Mattagami Limited Partnership (LMLP). During the first half of 2014, the Amisk-oo-Skow Finance Corporation made equity contributions to the LMLP to acquire a 25 per cent interest in the value of the incremental units at the Little Long GS and the Harmon GS. Life-to-date capital expenditures were $2,202 million as of June 30, 2014.

Atikokan Conversion

- Construction to convert the Atikokan GS from coal to use biomass fuel was completed in July 2014, ahead of its original target completion date of late August 2014. OPG has submitted documentation to the OPA to declare the Atikokan GS in Commercial Operation, effective as of July 24, 2014. The project's total cost is tracking to the approved budget of $170 million. The converted station has a capacity of 205 MW.

Thunder Bay Conversion to Advanced Biomass

- In June 2014, OPG and the Ontario Power Authority executed the Thunder Bay Biomass Energy Supply Agreement with respect to the conversion of one unit at the Thunder Bay GS to advanced biomass fuel. Upon completion, the converted unit is expected to have a capacity of approximately 150 MW. The Thunder Bay GS Advanced Biomass Conversion project has an approved cost estimate of $7 million and is expected to be placed in-service in the first half of 2015.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars – except where noted)	**2014**	**2013**	**2014**	**2013**
Earnings				
Revenue	**1,098**	1,190	**2,485**	2,445
Fuel expense	**154**	172	**303**	355
Gross margin	**944**	1,018	**2,182**	2,090
Operations, maintenance and administration	**666**	643	**1,336**	1,343
Depreciation and amortization	**181**	242	**362**	484
Accretion on fixed asset removal and nuclear waste management liabilities	**195**	190	**391**	379
Nuclear Funds (earnings) – a reduction to expense	**(217)**	(173)	**(377)**	(297)
Income from investments subject to significant influence	**(10)**	(9)	**(23)**	(19)
Other net expenses	**10**	10	**24**	28
Income before interest and income taxes	**119**	115	**469**	172
Net interest expense	**11**	20	**23**	45
Income tax (recovery) expense	**(8)**	22	**87**	26
Net income	**116**	73	**359**	101
Net income attributable to the Province	**115**	73	**357**	101
Net Income attributable to non-controlling interest [1]	**1**	-	**2**	-
Income (loss) before interest and income taxes				
Electricity generation business segments	**100**	118	**446**	227
Regulated – Nuclear Waste Management	**24**	(15)	**(10)**	(78)
Services, Trading, and Other Non-Generation	**(5)**	12	**33**	23
Total income before interest and income taxes	**119**	115	**469**	172
Cash flow				
Cash flow provided by operating activities	**205**	347	**633**	592
Electricity generation (TWh)				
Regulated – Nuclear Generation	**11.0**	10.9	**22.6**	22.5
Regulated – Hydroelectric				
Existing regulated hydroelectric generating stations	**4.7**	4.5	**9.5**	9.2
Hydroelectric generating stations subject to rate regulation effective July 1, 2014	**3.3**	3.7	**6.6**	7.1
Contracted Generation Portfolio [2]	**0.8**	0.9	**1.6**	2.5
Total electricity generation	**19.8**	20.0	**40.3**	41.3
Average sales prices and average revenue (¢/kWh)				
Average revenue for OPG [3]	**5.1**	5.6	**5.7**	5.6
Average revenue for all electricity generators, excluding OPG [4]	**10.7**	11.1	**10.4**	10.1
Nuclear unit capability factor (per cent)				
Darlington GS	**77.6**	85.9	**86.7**	85.0
Pickering GS	**77.4**	65.9	**72.0**	72.4
Availability (per cent)				
Regulated – Hydroelectric	**91.2**	92.0	**91.8**	92.6
Contracted Generation Portfolio – Hydroelectric	**87.0**	93.5	**91.4**	95.7
Equivalent forced outage rate				
Contracted Generation Portfolio – Thermal	**3.7**	5.7	**3.3**	10.1
Return on common equity for the twelve months ended June 30, 2014 and December 31, 2013 (per cent) [5]			**4.3**	1.5
Funds from operations interest coverage for the twelve months ended June 30, 2014 and December 31, 2013 (times) [5]			**2.7**	2.8

1 Relates to the 25 per cent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly-owned by the Moose Cree First Nation, in the incremental assets of the Lower Mattagami Limited Partnership.

2 Includes OPG's share of generation volume from its 50 per cent ownership interests in the Portlands Energy Centre (PEC) and Brighton Beach.

3 Average revenue for OPG is comprised of regulated revenues, market based revenues, revenues from energy supply agreements, and other energy revenue from cost recovery agreements. In 2014, average revenue for OPG excludes the revenue from the cost recovery agreement for termination costs for the Nanticoke GS and Lambton GS as these stations ended coal-fired operations in 2013. Average revenue for OPG also excludes OPG's share of revenues and generation from PEC and Brighton Beach.

4 Revenues for other electricity generators are calculated as the sum of hourly Ontario demand multiplied by the hourly Ontario electricity price (HOEP), plus total global adjustment payments, plus the sum of hourly net exports multiplied by the HOEP, less OPG's generation revenue, including revenue from the Nanticoke GS and Lambton GS cost recovery agreement.

5 "Funds from operations interest coverage" and "Return on common equity" are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about these measures is provided in OPG's Management's Discussion and Analysis for the period ended June 30, 2014, under the heading, *Supplementary Non-GAAP Financial Measures*.

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 six month periods ended June 30, 2014, 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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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2014 SECOND QUARTER REPORT

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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 Company) as at and for the three and six month periods ended June 30, 2014. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, related party 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 MD&A as at and for the year ended December 31, 2013.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario) (FAA), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In the first quarter of 2014, the Ontario Securities Commission (OSC) approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the heading, *Exemptive Relief for Reporting under US GAAP,* under the section *Changes in Accounting Policies and Estimates.* This MD&A is dated August 13, 2014.

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 section *Risk Management*. All forward-looking statements 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, generating station performance, cost of fixed asset removal and nuclear waste management, performance of investment funds, 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, electricity spot market prices, proposed new legislation, the ongoing evolution of the Ontario electricity industry, 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 was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province).

As at June 30, 2014, OPG's electricity generation portfolio had an in-service capacity of 16,931 megawatts (MW). OPG operates two nuclear generating stations, three thermal generating stations, 65 hydroelectric generating stations, and two wind power turbines. OPG also continues activities at two thermal generating stations to place the units in a laid-up state to preserve the option to convert them to natural gas and/or biomass in the future. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 580 MW Brighton Beach (Brighton Beach) gas-fired combined cycle GS. OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income of the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented in income from investments subject to significant influence under the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P. (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

OPG's Reporting Structure

Effective January 1, 2014, OPG revised the composition of its reportable business segments to reflect changes in its generation portfolio and its internal reporting. These changes primarily reflect 48 of OPG's hydroelectric generating facilities being prescribed for rate regulation, effective July 1, 2014, and ending the use of coal at the Nanticoke and Lambton generating stations in 2013. OPG's reportable business segments, effective January 1, 2014, are as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and other Non-Generation.

OPG's Regulated – Nuclear Generation and Regulated – Nuclear Waste Management segments are unchanged.

The Regulated – Hydroelectric segment continues to include the results of Sir Adam Beck 1, 2 and Pump GS, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. Beginning in the first quarter of 2014, this segment also includes the results of 48 hydroelectric stations which have been prescribed for rate regulation, effective July 1, 2014, under amended *Ontario Regulation 53/05*. The comparative information for the 48 hydroelectric stations, previously recorded under the Unregulated – Hydroelectric segment in OPG's second quarter 2013 MD&A and financial statements, has been reclassified to conform to this new presentation.

The Contracted Generation Portfolio segment includes the results of operating generation facilities that are not prescribed for rate regulation. The segment primarily includes generating facilities that are under an Energy Supply Agreement (ESA) or other long-term contracts with the Ontario Power Authority (OPA).

Activities of generating stations that are not currently subject to a contract or rate regulation, but are available to generate electricity for sale, if required, are also included in the Contracted Generation Portfolio segment. Since the Lambton GS and Nanticoke GS were generating electricity up to the end of 2013, the activities related to these stations for the comparative period are reported in the Contracted Generation Portfolio segment. Effective January 1, 2014, the activities related to the Lambton GS and Nanticoke GS are reported under the Services, Trading, and other Non-Generation business segment. These stations ended coal-fired operations as a result of the Shareholder declaration issued in March 2013 mandating that OPG end the use of coal at these stations by the end of 2013.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in the PEC and Brighton Beach stations. OPG's share of the in-service generating capacity and generation volume from its interests in the PEC and Brighton Beach stations are also included in this segment.

The Services, Trading, and other Non-Generation segment is a non-generation segment, and includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, sales of financial risk management products, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the United States (US) market. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in the revenue of this segment. In addition, this segment includes revenue from real estate rentals and other unregulated service revenues. The above activities were previously reported in the other segment.

Information for the comparative period has been adjusted to reflect the changes to OPG's reportable business segments and is labeled "adjusted".

The in-service generating capacity by business segment as of June 30, 2014 and December 31, 2013 was as follows:

	As at	
(MW)	**June 30 2014**	**December 31 2013** *(adjusted)*
Regulated – Nuclear Generation	**6,606**	6,606
Regulated – Hydroelectric [1]	**6,426**	6,432
Contracted Generation Portfolio [2]	**3,899**	3,752
Total	**16,931**	16,790

[1] Includes the capacity of 48 of OPG's hydroelectric generating facilities which have been prescribed for rate regulation, effective July 1, 2014, per the amended *Ontario Regulation 53/05.*

[2] Includes the capacity of two units at the Thunder Bay GS, until the conversion of one unit to use advanced biomass fuel has been completed. The balance also includes OPG's share of in-service generating capacity of 275 MW for PEC and 290 MW for Brighton Beach.

During the six months ended June 30, 2014, the in-service capacity of the Contracted Generation Portfolio segment increased by 147 MW. The increase was a result of a 78 MW unit at the Harmon GS being declared in-service in June 2014, and a 69 MW unit at the Little Long GS being declared in-service in January 2014. In addition, the in-service capacity of the Regulated – Hydroelectric segment decreased by 6 MW as a result of a reduction in the capacity of the units at the Aguasabon GS from 51 MW to 45 MW in May 2014.

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 section, *Discussion of Operating Results by Business Segment*.

(millions of dollars – except where noted)	Three Months Ended June 30 2014	Three Months Ended June 30 2013	Six Months Ended June 30 2014	Six Months Ended June 30 2013
Revenue	**1,098**	1,190	**2,485**	2,445
Fuel expense	**154**	172	**303**	355
Gross margin	**944**	1,018	**2,182**	2,090
Operations, maintenance and administration	**666**	643	**1,336**	1,343
Depreciation and amortization	**181**	242	**362**	484
Accretion on fixed asset removal and nuclear waste management liabilities	**195**	190	**391**	379
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(217)**	(173)	**(377)**	(297)
Property and capital taxes	**(1)**	14	**10**	29
Income from investments subject to significant influence	**(10)**	(9)	**(23)**	(19)
Restructuring	**10**	-	**12**	2
	824	907	**1,711**	1,921
Income before other loss (income), interest and income taxes	**120**	111	**471**	169
Other loss (income)	**1**	(4)	**2**	(3)
Income before interest and income taxes	**119**	115	**469**	172
Net interest expense	**11**	20	**23**	45
Income tax (recovery) expense	**(8)**	22	**87**	26
Net income	**116**	73	**359**	101
Net income attributable to the Province	**115**	73	**357**	101
Net income attributable to non-controlling interest [1]	**1**	-	**2**	-
Electricity production (TWh) [2]	**19.8**	20.0	**40.3**	41.3
Cash flow				
Cash flow provided by operating activities	**205**	347	**633**	592

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the incremental assets of the Lower Mattagami Limited Partnership (LMLP).

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach. Electricity production for the comparative period has been adjusted to include 50 percent of the production from PEC and Brighton Beach.

Second Quarter

Net income attributable to the Province increased by $42 million during the second quarter of 2014, compared to the same quarter in 2013. Income before interest and income taxes increased by $4 million. The following summarizes the significant items which caused the variance:

Significant factors that increased income before interest and income taxes:

- Higher earnings on the Used Fuel Segregated Fund (Used Fuel Fund) of $41 million primarily due to the impact of a higher Ontario consumer price index (CPI) on the committed return related to the first

2.23 million used fuel bundles, and favourable market conditions for the excess portion of the fund. This increase was net of the impact of the Bruce Lease Net Revenues Variance Account

- Higher generation volume from the generating stations included in the Lower Mattagami River project
- Lower salary costs of $15 million due to headcount reductions.

Significant factors that reduced income before interest and income taxes:

- Higher expenditures of $53 million for the Regulated – Nuclear Generation and Regulated – Hydroelectric segments primarily related to outage activities
- Higher restructuring expense of $10 million due to the recognition of severance costs primarily related to the Thunder Bay GS.

Income tax recovery was $8 million during the second quarter of 2014, compared to an expense of $22 million for the same quarter in 2013. The decrease in income tax expense was primarily due to the impact of a variance account authorized by the OEB related to the stations leased to Bruce Power.

<u>Year-To-Date</u>

Net income attributable to the Province increased by $256 million during the first six months of 2014, compared to the same period in 2013. Income before interest and income taxes increased by $297 million. The following summarizes the significant items which caused the variance:

Significant factors that increased income before interest and income taxes:

- Increase in revenue of approximately $230 million primarily as a result of higher electricity spot market prices and trading revenue, the majority of which occurred during the first quarter of 2014 as a result of the unseasonably cold winter
- Higher earnings on the Used Fuel Fund of $78 million, net of the impact of the Bruce Lease Net Revenues Variance Account
- Higher generation volume from the generating stations included in the Lower Mattagami River project and the Thunder Bay GS
- Lower salary costs of $28 million due to headcount reductions.

Significant factors that reduced income before interest and income taxes:

- Higher OM&A expenses of $44 million for the Regulated – Nuclear Generation and Regulated – Hydroelectric segments due to an increase in outage expenditures
- Higher accretion expense of $12 million as a result of an increase in the fixed asset removal and nuclear waste management liabilities
- Higher restructuring expense of $10 million due to the recognition of severance costs primarily related to the Thunder Bay GS.

Net interest expense decreased by $22 million for the six months ended June 30, 2014, compared to the same period in 2013. The decrease is primarily due to amounts recorded in the Capacity Refurbishment Variance Account in 2014 as a result of the Niagara Tunnel being declared in-service.

Income tax expense increased by $61 million for the first six months of 2014 compared to the same period in 2013. The increase was primarily a result of the increase in income during 2014.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment:

(millions of dollars)	Three Months Ended June 30 **2014**	Three Months Ended June 30 **2013** *(adjusted)*	Six Months Ended June 30 **2014**	Six Months Ended June 30 **2013** *(adjusted)*
(Loss) income before interest and income taxes				
Regulated – Nuclear Generation	**(11)**	15	**(11)**	(2)
Regulated – Hydroelectric	**102**	116	**409**	241
Contracted Generation Portfolio	**9**	(13)	**48**	(12)
Total electricity generation business segments	**100**	118	**446**	227
Regulated – Nuclear Waste Management	**24**	(15)	**(10)**	(78)
Services, Trading, and other Non-Generation	**(5)**	12	**33**	23
	119	115	**469**	172

Income before interest and income taxes from the electricity generation business segments decreased by $18 million during the second quarter of 2014, compared to the same quarter in 2013. The decrease was a result of lower earnings from OPG's regulated segments, primarily due to higher OM&A expenses related to planned outage activities, partially offset by higher earnings from the Contracted Generation Portfolio segment. The higher earnings from the Contracted Generation Portfolio segment was primarily due to higher generation volume from the generating stations included in the Lower Mattagami River project.

Earnings from the Services, Trading, and other Non-Generation business segment decreased by $17 million during the second quarter of 2014, compared to the same quarter in 2013. The decrease was primarily due to OM&A expenses incurred in 2014 related to placing the Nanticoke GS and Lambton GS in a laid-up state to preserve the option to convert them to natural gas and/or biomass in the future. The impact of higher OM&A expenses was partially offset by recoveries recognized during the quarter for property tax reassessments associated with the Lambton GS and the Nanticoke GS.

Income before interest and income taxes from the electricity generation business segments increased by $219 million for the first half of 2014, compared to the same period in 2013. The increase was primarily due to higher generation revenue from the Regulated – Hydroelectric segment as a result of higher electricity spot market prices received for the generation produced by the 48 hydroelectric generating stations that have been prescribed for rate regulation effective July 1, 2014.

The Contracted Generation Portfolio segment's income before interest and income taxes increased by $60 million for the first half of 2014 primarily due to the following:

- Higher revenue from the existing assets of the generating stations included in the Lower Mattagami River project. This increase in revenue was primarily a result of higher generation volume and higher electricity spot market prices. The existing assets of the Lower Mattagami River project are not subject to the revenue mechanism under the hydroelectric ESA until the last incremental unit of the Lower Mattagami River project is declared in-service. Until that time, the generation from these stations receives the electricity spot market price
- Higher revenue as a result of production from the incremental units at the Little Long GS and Harmon GS, which received revenue determined under the hydroelectric ESA
- Higher generation revenue for the Thunder Bay GS primarily due to higher generation volume and higher electricity spot market prices.

The increase in income before interest and income taxes of $10 million for the Services, Trading, and other Non-Generation business segment for the first half of 2014 was primarily a result of higher trading margins for electricity sold to neighbouring energy markets. This increase was partially offset by the impact of higher OM&A expenses as a result of including the results of the Nanticoke and Lambton generating stations in this segment.

The improvement in earnings for the Regulated – Nuclear Waste Management business segment of $39 million for the second quarter of 2014 and $68 million for the first half of 2014 was primarily a result of higher earnings on the Used Fuel Fund. The improvement in earnings was partially offset by higher accretion expense which reflects the increase in asset retirement obligations due to the passage of time.

Electricity Generation

Electricity generation for the three and six month periods ended June 30, 2014 and 2013 was as follows:

	Three Months Ended June 30		**Six Months Ended June 30**	
(TWh)	**2014**	**2013** *(adjusted)*	**2014**	**2013** *(adjusted)*
Regulated – Nuclear Generation	**11.0**	10.9	**22.6**	22.5
Regulated – Hydroelectric				
Existing regulated hydroelectric generating stations	**4.7**	4.5	**9.5**	9.2
Hydroelectric generating stations prescribed for rate regulation effective July 1, 2014	**3.3**	3.7	**6.6**	7.1
Contracted Generation Portfolio [1]	**0.8**	0.9	**1.6**	2.5
Total OPG electricity generation	**19.8**	20.0	**40.3**	41.3
Total electricity generation by all other generators in Ontario	**16.7**	16.7	**36.6**	35.5

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

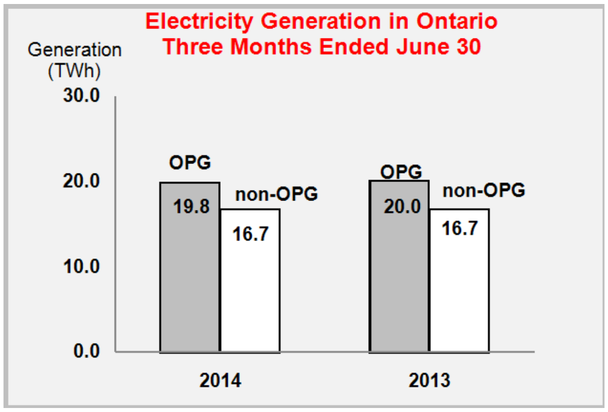
During the second quarter of 2014, lower water levels on river systems in northeastern and eastern Ontario contributed to a decrease in generation of 0.4 TWh from the hydroelectric stations prescribed for rate regulation effective July 1, 2014. An increase in Surplus Baseload Generation conditions also reduced production from these stations during this quarter.

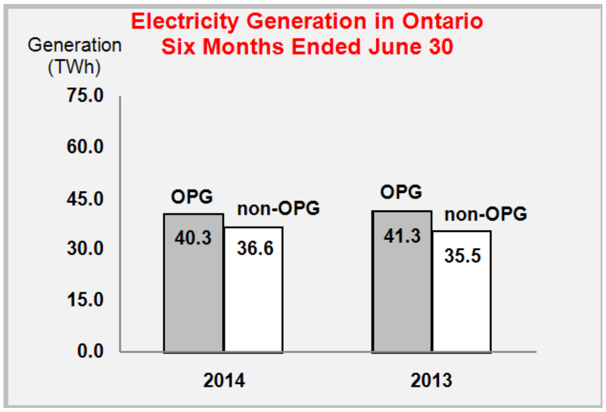
For the existing regulated hydroelectric generating stations, the increase in electricity generation of 0.2 TWh during the second quarter of 2014 was a result of higher generation from the Saunders GS due to higher water levels on the St. Lawrence River.

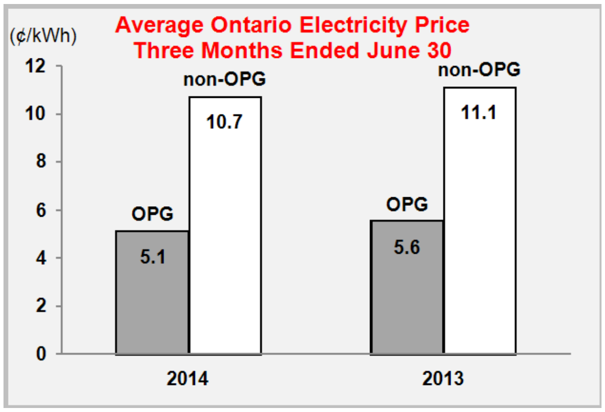
The decrease in electricity generation from the Contracted Generation Portfolio segment was primarily due to lower generation associated with the Nanticoke GS and the Lambton GS of 0.4 TWh as a result of ending coal-fired operations at these stations in 2013, in accordance with the Shareholder declaration issued in March 2013. This decrease was partially offset by higher generation primarily from the stations included in the Lower Mattagami River project.

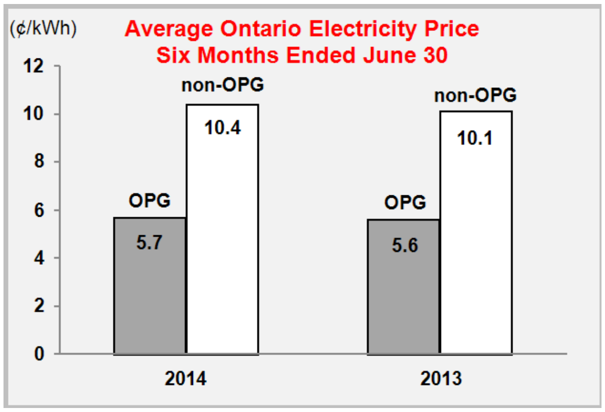
For the six months ended June 30, 2014, the decrease in generation of 1.0 TWh was mainly due to lower generation from the Contracted Generation Portfolio segment and lower production from the hydroelectric stations prescribed for rate regulation effective July 1, 2014.

Lower generation from the Contracted Generation Portfolio segment was primarily due to the decrease in generation of 1.7 TWh as a result of ending coal-fired operations at the Lambton GS and the Nanticoke GS in 2013, partially offset by higher generation of 0.6 TWh from the stations included in the Lower Mattagami River project, the Lennox GS, and the Thunder Bay GS.









Average Sales Prices and Average Revenue

OPG's average revenue reflects the average sales prices for all of its electricity generation segments. The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The regulated prices authorized by the OEB for electricity generated from nuclear facilities operated by OPG and existing regulated hydroelectric generating stations are discussed in OPG's annual MD&A under the heading, *Revenue Mechanisms for Regulated and Unregulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment during the three and six month periods ended June 30, 2014 was 5.5 ¢/kWh compared to 5.7 ¢/kWh during the same periods in 2013. The decrease was primarily due to a lower rate rider during 2014 related to the recovery of approved variance and deferral account balances.

The average sales price for the Regulated – Hydroelectric segment during the second quarter of 2014 was 3.4 ¢/kWh compared to 3.3 ¢/kWh during the same quarter in 2013. Beginning in 2014, the Regulated – Hydroelectric segment includes the results of 48 hydroelectric stations which have been prescribed for rate regulation, effective July 1, 2014. Prior to the OEB establishing regulated rates for these 48 stations, the generation from these stations will continue to receive the Ontario electricity spot market price. The average sales price for these stations during the second quarter of 2014 was 2.7 ¢/kWh compared to 2.4 ¢/kWh during the same quarter in 2013. The increase was primarily due to an increase in the weighted average hourly Ontario electricity price (HOEP) during the quarter. The increase in the average sales price for the Regulated – Hydroelectric segment was partially offset by a lower rate rider during 2014 for the existing regulated stations.

During the six months ended June 30, 2014, the average sales price for the Regulated – Hydroelectric segment was 4.5 ¢/kWh compared to 3.4 ¢/kWh during the same period in 2013. The increase in average sales price during the first half of the year was primarily due to higher sales prices related to the stations which have been prescribed for rate regulation, effective July 1, 2014. The increase in the average sales price for these stations was primarily due to the unseasonably cold temperatures during the first quarter of 2014 compared to the same quarter in 2013. The colder temperature resulted in higher natural gas prices and higher Ontario primary demand.

The average revenue for the three and six month periods ended June 30, 2014 was as follows:

	Three Months Ended June 30		**Six Months Ended June 30**	
(¢/kWh)	**2014**	**2013** *(adjusted)*	**2014**	**2013** *(adjusted)*
Average revenue for OPG [1]	**5.1**	5.6	**5.7**	5.6
Average revenue for all electricity generators, excluding OPG [2]	**10.7**	11.1	**10.4**	10.1

[1] Average revenue for OPG is comprised of regulated revenues, market based revenues, revenues from ESAs, and other energy revenue from cost recovery agreements. In 2014, average revenue for OPG excludes the revenue from the cost recovery agreement for termination costs for the Nanticoke GS and Lambton GS as these stations ended coal-fired operations in 2013. Average revenue for OPG also excludes OPG's share of revenues and generation from PEC and Brighton Beach.

[2] Revenues for other electricity generators are calculated as the sum of hourly Ontario demand multiplied by the HOEP, plus total global adjustment payments, plus the sum of hourly net exports multiplied by the HOEP, less OPG's generation revenue, including revenue from the Nanticoke GS and Lambton GS cost recovery agreement.

Cash Flow from Operations

Cash flow provided by operating activities for the three months ended June 30, 2014 was $205 million, compared to $347 million for the same quarter in 2013. This decrease in cash was primarily due to lower cash receipts as a result of lower rate riders and lower non-energy revenue. In addition, there were higher cash payments for OM&A and restructuring expenditures during the quarter.

Cash flow provided by operating activities for the six months ended June 30, 2014 was $633 million, compared to $592 million for the same period in 2013. This increase in cash was primarily due to the impact of higher electricity spot market prices and higher trading revenues.

Funds from Operations Interest Coverage

Funds from Operations (FFO) Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. FFO Interest Coverage is measured over a 12-month period. FFO Interest Coverage for the twelve months ended June 30, 2014 was 2.7 times and 2.8 times for December 31, 2013. The FFO Interest Coverage decreased primarily due to an increase in interest costs, which was partially offset by higher cash flows provided by operating activities. The increase in interest costs was primarily due to higher pension and OPEB discount rates, and an increase in pension and OPEB benefit obligations.

Return on Common Equity

Return on Common Equity (ROE) is an indicator of OPG's performance consistent with its objectives to operate on a financially sustainable basis and to maintain value for the Shareholder. ROE is measured over a 12-month period. ROE for the twelve months ended June 30, 2014 was 4.3 percent and 1.5 percent for December 31, 2013. ROE increased for the period primarily due to higher net income attributable to the Province.

FFO Interest Coverage and ROE are not measurements in accordance with US GAAP and should not be considered as alternative measures to net income, cash flows from operating activities, or any other measure of performance under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of performance and are consistent with the corporate strategy to operate on a financially sustainable basis. The definition and calculation of FFO Interest Coverage and ROE can be found under the section, *Supplementary Non-GAAP Financial Measures.*

Recent Developments

New Nuclear Units

The Government of Ontario's 2013 Long-Term Energy Plan indicated that it will not proceed at this time with the construction of two new nuclear reactors at the Darlington site, however, the Ministry of Energy will work with OPG to maintain the site preparation licence granted by the Canadian Nuclear Safety Commission (CNSC). As such, OPG is undertaking activities required to support the Environmental Assessment (EA) and existing licence.

On May 14, 2014, OPG received the decision of the Federal Court (Canada) on a judicial review of the issuance of the Power Reactor Site Preparation Licence and a judicial review in relation to the Darlington New Nuclear Project EA. As a result of the decision, the Federal Court nullified the site preparation licence issued by the CNSC. The Federal Court ordered that the EA be returned to the Joint Review Panel (or a duly constituted panel) for additional consideration of three matters:

- gaps in the bounding scenario regarding hazardous substance emissions and on-site chemical inventories
- deferral of the analysis of a severe common cause accident
- gaps in the analysis of spent nuclear fuel.

OPG, the Attorney General for Canada, and the CNSC are appealing this decision to the Federal Court of Appeals.

New OPG Capacity In-Service

Since the end of the first quarter in 2014, the following assets were declared in-service:

- *Lower Mattagami:* The 78 MW incremental unit at the Harmon GS was declared in-service on June 3, 2014, ahead of its original target completion date of September 2014.
- *Atikokan Biomass Conversion:* Construction to convert the Atikokan GS from coal to biomass fuel was completed in July 2014, ahead of its original target completion date of late August 2014. OPG has submitted documentation to the OPA to declare the Atikokan GS in Commercial Operation, effective as of July 24, 2014. The project's total cost is tracking to the approved budget of $170 million. The converted station has a capacity of 205 MW.

OPG's major generation development projects are discussed under the heading, *Project Excellence*.

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 mission is to be Ontario's low cost electricity generator through a focus on three corporate strategies:

- Operational Excellence
- Project Excellence
- Financial Sustainability.

The following sections provide an update to OPG's disclosures related to operational excellence, project excellence, and financial sustainability. A detailed discussion of OPG's three corporate strategies is included in the 2013 annual MD&A under the headings, *Operational Excellence, Project Excellence,* and *Financial Sustainability*.

Operational Excellence

Operational excellence at OPG's nuclear, hydroelectric, and thermal generating facilities is accomplished by generating safe, reliable, and cost-effective electricity.

Nuclear Generating Assets

In April 2014, the Darlington Nuclear GS received its second consecutive excellent safety and performance evaluation from the World Association of Nuclear Operators.

During the second quarter of 2014, planned maintenance outages commenced and were completed at Unit 1 of the Darlington Nuclear GS. The planned outages at Pickering Units 4 and 8 were completed. In addition, planning activities for the Vacuum Building Outage scheduled to be executed at the Darlington Nuclear GS in 2015 are underway.

In 2013, the CNSC approved a five-year operating licence which combines the Pickering A and B Nuclear generating stations' licences into a single-site licence. A regulatory hold point was added to the licence related to fuel channels and the original assumed end-of-life dates for Pickering Units 5 to 8. To satisfy the requirements for removal of the hold point, OPG provided the results of additional safety assessments in a May 2014 Commission Hearing with public participation, as required by the CNSC. In June 2014, the CNSC approved OPG's request to remove the hold point on the licence for the Pickering Nuclear GS. The removal of this hold point authorizes the Pickering Nuclear GS to proceed with plans to operate Units 5 to 8 up to 247,000 equivalent full power hours. OPG's current Power Reactor Operating Licence for the Pickering Nuclear GS expires on August 31, 2018.

The current Darlington Nuclear GS Power Reactor Operating Licence expires on December 31, 2014. In December 2013, OPG submitted an application for a licence renewal that would span the refurbishment period. The CNSC hearing is scheduled for November 2014. In June 2014, OPG requested an extension to the existing licence to provide additional time to complete engineering studies for the Darlington Nuclear GS. The extension would also allow for more public consultation prior to the final submissions and hearing process. In July 2014, OPG received an extension to the existing licence to December 31, 2015.

Generation and reliability performance at the Pickering and Darlington Nuclear generating stations during the second quarter of 2014 are discussed under the heading, *Regulated – Nuclear Generation Segment* in the section *Discussion of Operating Results by Business Segment*.

Hydroelectric Generating Assets

OPG's hydroelectric generating stations that are currently prescribed for rate regulation and the stations which have been prescribed for rate regulation effective July 1, 2014 are included in the Regulated – Hydroelectric segment. Hydroelectric generating stations that are not subject to rate regulation by the OEB are included in the Contracted Generation Portfolio segment. A description of these reportable business segments is included under the heading, *OPG's Reporting Structure*.

In consideration of current and future market conditions and the related revenue mechanisms, OPG continues to evaluate and implement plans to increase capacity, maintain performance, and extend the operating life of its hydroelectric generating assets. During the second quarter of 2014, OPG completed major equipment overhauls and rehabilitation work on Unit 5 of the Des Joachims GS and Unit 3 of the Pine Portage GS. Rehabilitation work on Unit 3 of the Sir Adam Beck Pump GS continues. Other hydroelectric generation projects are discussed under the heading, *Project Excellence*.

Thermal Generating Assets

OPG's operating thermal generating stations are included in the Contracted Generation Portfolio segment. These stations operate as peaking facilities, depending on electricity demand. In April 2014, OPG ended all coal-fired operations as all existing coal inventory was utilized in the last coal-fired unit at the Thunder Bay GS. Discussions related to the conversion of the Atikokan and Thunder Bay generating stations are included under the heading, *Project Excellence*.

Thermal assets that are no longer available to generate electricity are included in the Services, Trading, and other Non-Generation segment once the assets are removed from service. With the end of coal-fired generation at the Nanticoke GS and the Lambton GS in 2013, OPG continues activities at these stations related to placing the units in a laid-up state to preserve the option to convert them to natural gas and/or biomass in the future. These activities are reflected in the Services, Trading, and other Non-Generation segment in 2014. OPG is seeking recovery of ongoing costs to preserve the option to convert the units.

Environmental Performance

During the first half of 2014, there were no significant changes to environmental legislation affecting the Company. There was a reduction in environmental risk as the Company's largest coal-fired stations, the Lambton and Nanticoke generating stations, ended coal-fired operations by the end of 2013. In addition, OPG ended all coal-fired operations in April 2014 as all existing coal inventory was utilized in the last coal-fired unit at the Thunder Bay GS. As a result, carbon dioxide and acid gas emissions decreased by 89 percent during the first half of 2014, compared to the same period in 2013.

Disclosures relating to environmental policies and procedures, and environmental risks are provided in the 2013 annual MD&A.

Project Excellence

OPG is pursuing several generation development projects. OPG's major projects include the Darlington refurbishment, new hydroelectric generation and plant expansions, and the conversion of coal-fired generating units to alternative fuels. The status of OPG's major projects as of June 30, 2014 are outlined below.

Project	**Capital expenditures**		**Approved budget**	**Planned in-service date**	**Status**
(millions of dollars)	**Year-to-date**	**Life-to-date**			
Darlington Refurbishment	355	1,148			This project is part of Ontario's Long-Term Energy Plan. A detailed cost and schedule estimate for the refurbishment of the four units is expected to be completed in 2015. See update below.
Lower Mattagami	220	2,202	2,600	June 2015	Project is on budget and on schedule. See update below.
Deep Geologic Repository for Low and Intermediate Level Waste [1]	3 [1]	170 [1]			Public hearings continue with additional hearing days scheduled to commence in September 2014.
Atikokan Biomass Conversion	20	164	170	August 2014	Construction completed ahead of schedule and on budget. See update below.

[1] Expenditures are funded by the nuclear fixed asset removal and nuclear waste management liabilities.

Darlington Refurbishment

The Darlington Refurbishment project is a multi-phase program comprised of individual projects of various scales and sizes. In particular, the project consists of the following five major project work packages:

- Re-tube and Feeder Replacement
- Turbines and Generators
- Defueling and Fuel Handling
- Steam Generators
- Balance of Plant.

The Darlington Refurbishment project is currently in the definition phase. Refurbishment of the four Darlington units is currently estimated to cost less than the $10 billion high confidence estimate in 2013 dollars, excluding capitalized interest and escalation. A detailed cost and schedule estimate for the refurbishment of the four units is expected to be completed in 2015.

There are 19 pre-requisite projects currently underway at Darlington that are to be completed in advance of the execution phase. A small number of these projects are experiencing execution challenges that have resulted in cost and schedule changes for those projects. This is not expected to alter the overall cost and schedule of the Darlington Refurbishment project. Early in 2014, in response to these challenges, OPG began implementing corrective actions such as new collaborative planning processes with vendors, dedicating resident engineers in vendor offices, exercising contract audit rights, and negotiating contract amendments.

On July 2, 2014, OPG submitted updated evidence on the Darlington Refurbishment project to the OEB in support of its current application for new regulated prices effective January 1, 2014 to ensure transparency of risks. Included in the update was a May 2014 external oversight report produced for OPG's Nuclear Oversight Committee of the Board of Directors by Burns & McDonnell Canada Ltd. and Modus Strategic Solutions Canada Company which confirmed the challenges being encountered and supported OPG's action plans to address the issues. The cost variances for the pre-requisite projects are estimated to be 2 to 3 percent of the Darlington Refurbishment project's high confidence estimate and are within the contingency and management reserve that are part of the total project cost estimate. OPG remains confident that the cost of the Darlington Refurbishment project will remain less than the $10 billion high confidence estimate in 2013 dollars, excluding capitalized interest and escalation. OPG continues to assess the effectiveness of the measures taken.

The CNSC has set out the regulatory requirements in *Life Extension of Nuclear Power Plants* (RD-360). In line with these requirements, OPG submitted the Global Assessment Report (GAR) and the Integrated Implementation Plan (IIP) to the CNSC in December 2013. In April 2014, the CNSC accepted the GAR as meeting all regulatory requirements of RD-360 and provided feedback on the IIP. In June 2014, OPG requested an extension to the existing operating licence to provide additional time to complete engineering studies for the Darlington Nuclear GS. In addition, the extension will provide sufficient time for OPG to make relevant information publicly available to facilitate public engagement in the licence renewal process. For further details on the Darlington Nuclear GS licence extension, refer to the heading, *Nuclear Generating Assets*. Due to the delay in the process for the extended Darlington Nuclear GS licence, IIP approval by the CNSC is also delayed. To mitigate, OPG will be requesting CNSC staff acceptance of the IIP by December 31, 2014. OPG is reviewing options to obtain certainty of regulatory scope prior to the release of the detailed cost and schedule estimate in 2015. The regulatory scope identified in the IIP represents the known regulatory work for refurbishment and the Darlington Nuclear GS life extension.

Lower Mattagami

The 78 MW incremental unit at the Harmon GS was declared in-service on June 3, 2014, ahead of its original target completion date of September 2014. This is the second incremental unit to be completed on the Lower Mattagami River project, as the incremental unit at the Little Long GS was declared in-service in the first quarter of 2014. In addition, the first 89 MW incremental unit at the Smoky Falls GS is expected to be declared in-service ahead of its original target completion date of November 2014.

As incremental units are placed in-service, the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, may acquire up to a 25 percent interest in the assets through its investment in the LMLP. During the first half of 2014, the Amisk-oo-Skow Finance Corporation made equity contributions of $53 million to LMLP to acquire a 25 percent interest in the value of the incremental units at the Little Long GS and Harmon GS.

Atikokan Conversion

In July 2014, construction to convert the Atikokan GS from coal to biomass fuel was completed, ahead of its original target completion date of late August 2014. OPG has submitted documentation to the OPA to declare the Atikokan GS in Commercial Operation, effective as of July 24, 2014. While the total project cost is being finalized, the project's total cost is tracking to the approved budget of $170 million. The converted station has a capacity of 205 MW and is subject to an energy supply agreement with the OPA, which was executed in 2012.

The following key activities were completed during the second quarter of 2014 prior to the station being declared in-service:

- Received delivery of its first biomass pellets for generation and successfully fired a row of burners and generated its first electricity using biomass fuel in May 2014
- Obtained certification for the burner management system, operated using full capacity without natural gas ignition support, and completed all systems training in June 2014.

Thunder Bay Advanced Biomass Conversion

In June 2014, OPG and the OPA executed the Thunder Bay Biomass ESA with respect to the conversion of the Thunder Bay GS to advanced biomass fuel. OPG has approved the full release of the project and the project is now in the execution phase. Upon completion, one converted unit in the station is expected to have an in-service capacity of approximately 150 MW. The Thunder Bay Advanced Biomass Conversion project has an approved cost estimate of approximately $7 million and is expected to be placed in-service in the first half of 2015.

Financial Sustainability

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of financial performance that will ensure its long-term financial sustainability and maintain the value of its assets for its Shareholder – the Province of Ontario. Inherent in this priority are three objectives:

- enhance profitability by increasing revenue
- improve efficiency and reduce costs
- ensure a strong financial position that enhances OPG's ability to finance its operations and generation development projects.

Revenue Growth

OPG's revenue strategy focuses on revenue growth, while taking into account the impact on Ontario electricity ratepayers by setting challenging business planning targets. Currently, OPG has multiple sources of revenue, including:

- regulated revenue from nuclear and most baseload hydroelectric generating facilities
- contract revenue from ESAs and cost recovery agreements for most of its remaining unregulated facilities
- unregulated revenue based on electricity spot market prices for certain facilities that are not prescribed a regulated price or not subject to revenue from an ESA
- non-generation revenues.

Effective July 1, 2014, an amendment to *Ontario Regulation 53/05* requires OPG's 48 previously unregulated hydroelectric stations that are not under an ESA to be prescribed for rate regulation.

OPG's objectives in all applications for regulated prices are to clearly demonstrate that costs for its regulated operations are prudently incurred and should be fully recovered, and to earn an appropriate return on its regulated assets.

In September 2013, OPG filed an application with the OEB for new regulated prices effective January 1, 2014. During the second quarter of 2014, as part of common regulatory practice, OPG filed an update to the requested regulatory prices, including rate riders, to reflect material changes from forecast information provided in its application. OPG's update requests that the nuclear generation regulated price, excluding rate riders, decrease from the previous request of $69.91/MWh to $67.60/MWh and the regulated price, excluding rate riders, for the generation from the existing regulated hydroelectric facilities increase from the previous request of $42.31/MWh to $42.75/MWh. For the 48 newly regulated stations, effective July 1, 2014, OPG decreased the requested hydroelectric generation regulated price, excluding rate riders, from the previous request of $47.59/MWh to $47.57/MWh. In addition, the requested rate riders were updated to $1.35/MWh for the output from the nuclear facilities and $3.36/MWh for the output from the existing regulated hydroelectric facilities, based on the final December 31, 2013 variance and deferral account balances and updated production forecasts. These prices would allow OPG to recover its costs for these stations while earning an appropriate return on these assets. The decision on OPG's application will be made by the OEB following a public hearing process, which is currently ongoing. The oral hearing portion of the process concluded on July 18, 2014. The OEB's decision is expected in the fourth quarter of 2014. OPG is also planning a future rate application during 2014 to request recovery of variance and deferral account balances as at December 31, 2014.

OPG has negotiated ESAs and cost recovery agreements for some of its unregulated hydroelectric assets and its thermal assets, and continues to negotiate ESAs for new development and conversion projects.

During the first half of 2014, a portion of OPG's electricity production from certain unregulated facilities was sold at the Ontario electricity spot market price. This includes production from stations that are prescribed for rate regulation effective July 1, 2014. OPG's financial results benefited from the increase in Ontario electricity spot market prices during this period primarily due to unseasonably cold temperatures in Ontario during January and February 2014.

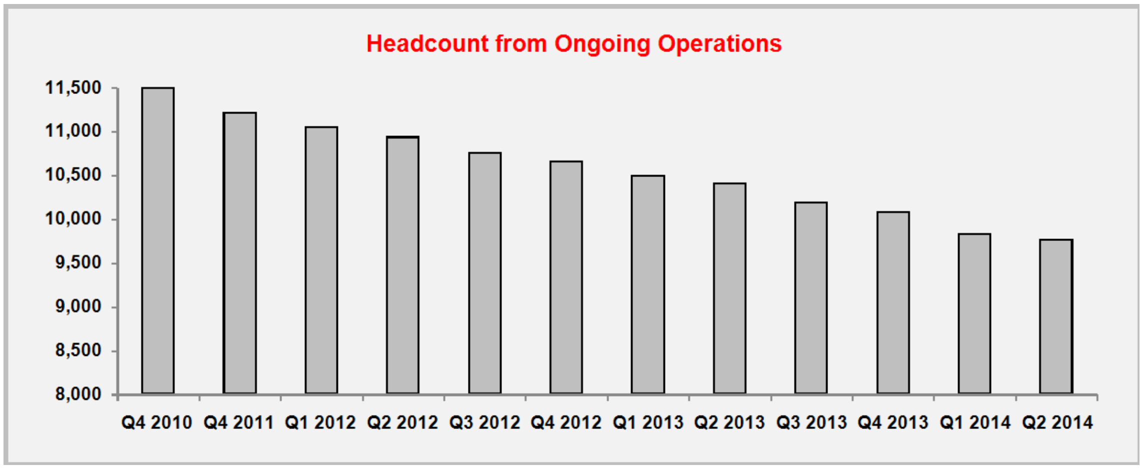
OPG also earns non-electricity generation revenues through a number of sources, including: isotope and heavy water sales; the lease of the Bruce A and B nuclear stations; joint ventures associated with PEC and Brighton Beach; trading and other non-hedging activities; real estate rentals and sales; and the provision of technical and engineering services to third parties. During the first half of 2014, OPG's trading revenue significantly increased from higher prices realized on interconnected market sales to neighbouring energy markets.

To increase non-generation revenues, OPG, through its wholly owned subsidiary, Canadian Nuclear Partners, continues to explore opportunities to provide management and technical services to other utilities and power sector organizations.

Improving Efficiency and Reducing Costs

OPG is aggressively pursuing efficiency and productivity improvements while reducing costs. To accomplish this, OPG launched a multi-year Business Transformation initiative in 2011 to create a streamlined company with a sustainable cost structure. OPG has implemented a centre-led organizational model to more efficiently utilize its resources. Each business unit has launched initiatives to improve efficiencies and reduce work through process streamlining. These initiatives are driving sustainable change, while ensuring that there is no adverse impact on the safety, reliability, and environmental sustainability of OPG's operations.

OPG plans to use attrition to reduce its year-end 2016 headcount from ongoing operations by over 2,300 employees from the 2011 level. This reduction is expected to result in lower labour costs compared to the 2011 level. During the January 1, 2011 to June 30, 2014 period, OPG's headcount from ongoing operations has been reduced by over 1,900, primarily through attrition. The reduction in headcount has already saved OPG approximately $400 million over the period from January 1, 2011 to June 30, 2014.



Strengthening Financial Position

In addition to its initiatives to increase revenue, achieve efficiencies, and reduce costs, OPG also employs the following four strategies to strengthen its financial position:

- **Ensure sufficient liquidity:** OPG's primary sources of liquidity and capital include funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), and capital market financing. During the first half of 2014, cash flow provided by operating activities increased by $41 million, compared to the same period in 2013. OPG renewed and extended its $1 billion bank credit facility to May 2019 during the second quarter of 2014. OPG also has access to a $500 million general corporate credit facility with the OEFC which will expire on December 31, 2014. OPG intends to continue to access the capital markets, where appropriate, to obtain cost effective financing for generation development projects.

- **Maintain an investment grade credit rating:** OPG's current investment grade credit ratings have enabled it to secure financing at cost effective interest rates. During the first quarter of 2014, Standard & Poor's reaffirmed OPG's long-term credit rating at A- with a negative outlook, and DBRS Ltd. re-affirmed the long-term credit rating on OPG's debt at A (low) and the commercial paper rating at R-1 (low). All ratings from DBRS Ltd. have a stable outlook.

- **Ensure that generation development projects are economic and provide for cost recovery and an appropriate return:** During the second quarter of 2014, OPG continued to negotiate ESAs for new development and conversion projects. Updates on these projects for the second quarter of 2014 are discussed under the heading *Project Excellence* in the section, *Core Business and Strategy*.

- **Evaluate financial performance:** OPG continuously evaluates its financial performance using key credit rating and financial metrics, including ROE, and FFO Interest Coverage. For further details, refer to the ROE and FFO Interest Coverage disclosure in the section, *Supplementary Non-GAAP Financial Measures*.

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, environmental, and safety performance. OPG evaluates the performance of its generating stations using a number of key performance indicators. The measures used vary depending on the generation technology.

Effective January 1, 2014, OPG revised the composition of its reportable business segments to reflect changes in its generation portfolio and its internal reporting. After ending coal-fired operations at the Nanticoke GS and the Lambton GS, OPG no longer uses the Thermal Start Guarantee Rate and the Thermal OM&A Expense per MW as indicators of performance. In addition, OPG previously reported Nuclear Production Unit Energy Cost and hydroelectric Equivalent Forced Outage Rate (EFOR). Effective January 1, 2014, OPG has moved to Nuclear Total Generating Cost (TGC) per MWh as a cost performance indicator for its nuclear generating facilities and reports Hydroelectric Availability as the only measure of the reliability of its hydroelectric generating facilities. OPG continues to report the Nuclear Unit Capability Factor as a measure of its nuclear station performance, and Hydroelectric OM&A expense per MWh as a measure of the cost effectiveness of its hydroelectric generating facilities.

Nuclear Total Generating Cost per Megawatt hour

Nuclear TGC per MWh is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as the total of fully-allocated OM&A expenses from ongoing nuclear operations, including total pension and OPEB costs, nuclear fuel expense including expenses related to used fuel storage and disposal, and capital project costs for ongoing nuclear operations, divided by net nuclear electricity generation.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2014**	**2013**	**2014**	**2013**
Regulated generation sales	**606**	618	**1,244**	1,282
Variance accounts	**(72)**	82	**(164)**	8
Other	**149**	(3)	**311**	142
Total revenue	**683**	697	**1,391**	1,432
Fuel expense	**73**	71	**149**	145
Variance and deferral accounts	**(17)**	(14)	**(33)**	(26)
Total fuel expense	**56**	57	**116**	119
Gross margin	**627**	640	**1,275**	1,313
Operations, maintenance and administration	**502**	463	**1,013**	990
Depreciation and amortization	**129**	155	**259**	311
Property and capital taxes	**7**	8	**14**	15
(Loss) income before other income, interest and income taxes	**(11)**	14	**(11)**	(3)
Other income	**-**	(1)	**-**	(1)
(Loss) income before interest and income taxes	**(11)**	15	**(11)**	(2)

The reduction in segment earnings of $26 million during the second quarter of 2014, compared to the same quarter in 2013, was primarily a result of an increase in OM&A expenses. Higher OM&A expenses of $39 million during the second quarter of 2014 was primarily due to an increase in expenditures related to planned outage activities at the Darlington Nuclear GS.

Lower segment earnings of $9 million during the six months ended June 30, 2014, compared to the same period in 2013, was also due to an increase in OM&A expenses.

Gross margin decreased by $13 million during the second quarter of 2014 and $38 million during the six months ended June 30, 2014, compared to the same periods in 2013, primarily due to a lower rate rider for nuclear generation in 2014. The impact of the lower rate rider was largely offset by a corresponding decrease in amortization expense related to regulatory balances.

The increase in other revenue for the three and six month periods ended June 30, 2014, compared to the same periods in 2013, was primarily due to the decrease in the fair value of the derivative liability embedded in the terms of the Bruce Power lease agreement (Bruce Lease). The changes in the fair value of this derivative are recorded in other revenue, with a corresponding change in the regulatory asset related to the Bruce Lease Net Revenues Variance Account. As such, there was no income impact related to the change in the fair value of the derivative liability.

The Unit Capability Factors for the Darlington and Pickering Nuclear generating stations and the Nuclear TGC per MWh were as follows:

	Three Months Ended June 30		**Six Months Ended June 30**	
	2014	**2013**	**2014**	**2013**
Unit Capability Factor *(%)*				
Darlington GS	**77.6**	85.9	**86.7**	85.0
Pickering GS	**77.4**	65.9	**72.0**	72.4
Nuclear TGC per MWh *($/MWh)*	**52.38**	51.24	**52.02**	52.52

The lower Unit Capability Factor at the Darlington Nuclear GS for the three months ended June 30, 2014, compared to the same period in 2013, was primarily due to an increase in planned outage days to conduct maintenance activities for Unit 1 which commenced during the quarter. The increase in Unit Capability Factor at the Pickering Nuclear GS was primarily due to a decrease in the number of planned outage days as well as improved reliability from the units during the quarter.

The higher Unit Capability Factor at the Darlington Nuclear GS for the six months ended June 30, 2014, was primarily due to a decrease in unplanned outage days compared to the same period in 2013 and the return of Darlington Unit 1 from its planned outage six days ahead of schedule. The slight decrease in the Unit Capability Factor at the Pickering Nuclear GS for the six months ended June 30, 2014 was primarily due to the following factors:

- an increase in the amount of planned outages, partially offset by
- a lower number of unplanned outage days, compared to the same period in 2013.

The increase in Nuclear TGC per MWh during the second quarter of 2014, compared to the same period in 2013, was primarily due to higher OM&A expenses for the segment. For the six month period ended June 30, 2014, the Nuclear TGC per MWh slightly decreased as a result of lower first quarter OM&A expenses offsetting the higher OM&A expense during the second quarter in 2014.

Regulated – Nuclear Waste Management Segment

(millions of dollars)	Three Months Ended June 30 2014	Three Months Ended June 30 2013	Six Months Ended June 30 2014	Six Months Ended June 30 2013
Revenue	**29**	28	**58**	53
Operations, maintenance and administration	**31**	30	**62**	57
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**191**	186	**383**	371
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(217)**	(173)	**(377)**	(297)
Income (loss) before interest and income taxes	**24**	(15)	**(10)**	(78)

Higher earnings on the Used Fuel Fund contributed to the improved earnings for the segment for the three and six month periods ended June 30, 2014, compared to the same periods in 2013. An increase in the Ontario CPI which affects the committed return related to the first 2.23 million used fuel bundles was the primary reason for the higher Used Fuel Fund earnings during the periods. Additionally, favourable market conditions resulted in higher earnings for the portion of the Used Fuel Fund related to the used fuel bundles that are in excess of the 2.23 million. The increased earnings in the segment were partially offset by higher accretion expense.

Regulated – Hydroelectric Segment

(millions of dollars)	Three Months Ended June 30 2014	Three Months Ended June 30 2013[1] *(adjusted)*	Six Months Ended June 30 2014	Six Months Ended June 30 2013[1] *(adjusted)*
Regulated generation sales [2]	**184**	180	**373**	363
Spot market sales	**88**	90	**348**	196
Variance accounts	**8**	21	**9**	32
Other	**36**	29	**82**	46
Total revenue	**316**	320	**812**	637
Fuel expense	**81**	82	**150**	150
Variance accounts	**6**	8	**8**	10
Total fuel expense	**87**	90	**158**	160
Gross margin	**229**	230	**654**	477
Operations, maintenance and administration	**85**	68	**161**	141
Depreciation and amortization	**41**	46	**82**	92
Property and capital taxes	**-**	-	**-**	1
Income before other loss, interest and income taxes	**103**	116	**411**	243
Other loss	**1**	-	**2**	2
Income before interest and income taxes	**102**	116	**409**	241

[1] The comparative amounts have been adjusted to include the activities of 48 of OPG's hydroelectric generating facilities that have been prescribed for rate regulation, effective July 1, 2014, per the amended *Ontario Regulation 53/05.*

[2] During each of the three months ended June 30, 2014 and 2013, the Regulated – Hydroelectric segment generation sales included revenue of $5 million related to the hydroelectric incentive mechanism for the existing regulated hydroelectric facilities. During the six months ended June 30, the Regulated – Hydroelectric segment generation sales included revenue of $12 million in 2014 and $7 million in 2013 related to the hydroelectric incentive mechanism for these facilities.

For the second quarter of 2014, higher OM&A expenses resulted in the decrease in the segment's income before interest and income taxes, compared to the same quarter in 2013. The increase in OM&A expenses was primarily due to an increase in a provision related to claims and overhaul expenditures incurred for Unit 3 at the Sir Adam Beck Pump GS.

The significant increase in income before interest and income taxes during the six months ended June 30, 2014, compared to the same period in 2013, was primarily due to higher gross margin. The increase in gross margin was primarily the result of significantly higher electricity spot market prices received during the first quarter of 2014 for the generation produced by the 48 hydroelectric generating stations that have been prescribed for rate regulation effective July 1, 2014. Higher ancillary services and other station revenue during the period also contributed to the higher gross margin for the segment. The higher gross margin during the six months ended June 30, 2014 was partially offset by a lower hydroelectric rate rider in 2014 and higher OM&A expenses. The impact of the lower rate rider was largely offset by a corresponding decrease in amortization expense related to regulatory balances.

The Regulated – Hydroelectric availability and OM&A expense per MWh were as follows:

	Three Months Ended June 30		Six Months Ended June 30	
	2014	**2013** *(adjusted)*	**2014**	**2013** *(adjusted)*
Hydroelectric Availability *(%)*	**91.2**	92.0	**91.8**	92.6
Hydroelectric OM&A expense per MWh *($/MWh)*	**9.8**	8.3	**9.6**	8.7

The hydroelectric availability during the second quarter of 2014 decreased slightly as a result of higher unplanned outages compared to the availability for the same period in 2013. The hydroelectric availability during the six months ended June 30, 2014 was slightly lower than the availability during the same period in 2013 due to higher planned outage days. The high availability reflects the continuing good performance of these regulated hydroelectric generating stations.

The increase in hydroelectric OM&A expense per MWh for the three and six month periods ended June 30, 2014, compared to the same periods in 2013, was primarily due to higher OM&A expenses.

Contracted Generation Portfolio Segment

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2014**	**2013** *(adjusted)*	**2014**	**2013** *(adjusted)*
Revenue	**64**	152	**157**	334
Fuel expense	**11**	25	**27**	76
Gross margin	**53**	127	**130**	258
Operations, maintenance and administration	**43**	108	**86**	204
Depreciation and amortization	**6**	36	**11**	71
Accretion on fixed asset removal liabilities	**2**	3	**4**	7
Property and capital taxes	**(4)**	3	**(3)**	7
Income from investments subject to significant influence	**(10)**	(9)	**(23)**	(19)
Restructuring	**7**	-	**7**	2
Income (loss) before other income, interest and income taxes	**9**	(14)	**48**	(14)
Other income	**-**	(1)	**-**	(2)
Income (loss) before interest and income taxes	**9**	(13)	**48**	(12)

For the 2013 three and six month comparative periods, the Contracted Generation Portfolio segment includes the operating results of the Nanticoke GS and Lambton GS, including revenue and expenses from generation and from the Contingency Support Agreement with the OEFC. Given these stations ended coal-fired generation at the end of 2013, the activities of these stations including expenses incurred in 2014 associated with placing the stations in reserve status, are being reported in the Services, Trading, and other Non-Generation segment effective January 1, 2014. The end of coal-fired operations and the change in presentation for the segment results in overall lower revenue, partially offset by lower OM&A and depreciation and amortization expenses for the three and six month periods ended June 30, 2014 compared to the same periods in 2013. The segment's results were also partially offset by the stations' net losses for the three and six month periods ended June 30, 2014 due to the costs of placing the stations in a laid-up state to preserve the option to convert them to natural gas and/or biomass in the future. OPG is seeking recovery of these ongoing costs to preserve the units.

The increase in segment income of $22 million during the second quarter in 2014, compared to the same quarter in 2013, was primarily due to the impact of higher generation volume for the existing assets of the Lower Mattagami River project and Thunder Bay GS. The incremental units at the Little Long GS and Harmon GS, also contributed to the increase in income as these stations were declared in-service in January 2014 and June 2014, respectively. In addition, property tax expenses decreased during the second quarter of 2014. The decrease was partly due to the recognition of property tax reassessments related to historical periods for the Atikokan GS and Lennox GS. These favourable changes were partially offset by higher restructuring expenses related to severance costs from staffing requirement changes resulting from OPG closing one unit at the Thunder Bay GS.

For the six months ended June 30, 2014, segment income increased by $60 million, compared to the same period in 2013. The increase was primarily due to higher generation volume from the stations included in the Lower Mattagami River project and the Thunder Bay GS. Higher electricity spot market prices during the first quarter of 2014 for generation from the existing assets of the Lower Mattagami River project and the Thunder Bay GS also contributed to the increase in segment income during the six month period. The existing assets of the Lower Mattagami River project are not subject to the revenue mechanism under the hydroelectric ESA until the last incremental unit of the Lower Mattagami River project is declared in-service. Similarly, effective January 1, 2014, generation from the Thunder Bay GS receives the electricity spot market price for production as it is no longer subject to a reliability-must-run contract. For the six months ended June 30, 2014, the HOEP was 5.1 ¢/kWh compared to 2.8 ¢/kWh during the same period in 2013.

The hydroelectric availability, hydroelectric OM&A expense per MWh, and the thermal EFOR for the segment were as follows:

	Three Months Ended June 30		**Six Months Ended June 30**	
	2014	**2013** *(adjusted)*	**2014**	**2013** *(adjusted)*
Hydroelectric Availability *(%)*	**87.0**	93.5	**91.4**	95.7
Hydroelectric OM&A expense per MWh *($/MWh)*	**24.0**	36.7	**24.0**	46.0
Thermal EFOR *(%)*	**3.7**	5.7	**3.3**	10.1

The hydroelectric availability during the second quarter of 2014 decreased by 6.5 percent compared to the same quarter in 2013 primarily as a result of an increase in unplanned outage days. The hydroelectric availability during the six months ended June 30, 2014 was lower by 4.3 percent compared to the availability during the same period in 2013 due to higher unplanned outage days. The high availability reflects the continuing good performance of these hydroelectric generating stations.

The decrease in hydroelectric OM&A expense per MWh for the three and six month periods ended June 30, 2014, compared to the same periods in 2013, was due to the impact of higher generation volume from the hydroelectric stations included in this segment.

The decrease in thermal EFOR for the three and six month periods ended June 30, 2014, compared to the same periods in 2013, was primarily a result of ending coal-fired operations at the Nanticoke GS and the Lambton GS in 2013.

Services, Trading, and other Non-Generation Segment

(millions of dollars)	Three Months Ended June 30 2014	Three Months Ended June 30 2013 *(adjusted)*	Six Months Ended June 30 2014	Six Months Ended June 30 2013 *(adjusted)*
Revenue	**34**	20	**123**	40
Fuel expense	**-**	-	**2**	-
Gross margin	**34**	20	**121**	40
Operations, maintenance and administration	**33**	1	**70**	2
Depreciation and amortization	**5**	5	**10**	10
Accretion on fixed asset removal liabilities	**2**	1	**4**	1
Property and capital taxes	**(4)**	3	**(1)**	6
Restructuring	**3**	-	**5**	-
(Loss) income before other income, interest and income taxes	**(5)**	10	**33**	21
Other income	**-**	(2)	**-**	(2)
(Loss) income before interest and income taxes	**(5)**	12	**33**	23

The inclusion of the results of the Nanticoke GS and the Lambton GS in this segment, as discussed under the section, *The Company*, resulted in higher revenue and OM&A expenses for both the three and six month periods ended June 30, 2014, compared to the same periods in 2013. The increase in OM&A expenses was largely offset by revenue for termination costs as provided for under the Contingency Support Agreement with the OEFC for these stations. The agreement's early termination provision allows OPG to recover actual costs incurred that cannot be reasonably avoided or mitigated during 2014.

The decrease in earnings of $17 million during the second quarter of 2014, compared to the same quarter in 2013, was primarily due to higher OM&A expenses and restructuring costs. OM&A expenses increased in 2014 as a result of placing the Nanticoke GS and Lambton GS in a laid-up state to preserve the option to convert them to natural gas and/or biomass in the future. OPG is seeking recovery of these ongoing costs to preserve the units. This was partially offset by recoveries recognized during the second quarter of 2014 related to property tax reassessments associated with the Lambton GS and the Nanticoke GS.

For the six month period ended June 30, 2014, the segment's income increased by $10 million as a result of the exceptional results from higher interconnected market sales during the first quarter of 2014. The unseasonably cold winter during the first quarter of 2014 provided interconnected market sales opportunities which resulted in higher trading margin for electricity sold to neighbouring energy markets. The increase in earnings was partially offset by higher OM&A expenses.

Income Taxes

Income tax recovery for the three months ended June 30, 2014 was $8 million compared to income tax expense of $22 million for the same quarter in 2013. The decrease in income tax expense was primarily due to the impact of a variance account authorized by the OEB related to the stations leased to Bruce Power, and a reduction in income tax liabilities in 2014 related to the resolution of tax uncertainties.

Income tax expense for the six months ended June 30, 2014 was $87 million compared to $26 million for the same period in 2013. The increase in income tax expense was primarily due to an increase in income before taxes mainly due to higher electricity spot market prices and trading revenue.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital include funds generated from operations, bank financing, credit facilities provided by the OEFC, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies; to fund obligations such as contributions to the pension fund and the Used Fuel Fund and the Decommissioning Segregated Fund (together the Nuclear Funds); and to service and repay long-term debt.

Changes in cash and cash equivalents were as follows:

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2014**	**2013**	**2014**	**2013**
Cash and cash equivalents, beginning of period	**755**	560	**562**	413
Cash flow provided by operating activities	**205**	347	**633**	592
Cash flow used in investing activities	**(350)**	(396)	**(735)**	(789)
Cash flow provided by financing activities	**15**	188	**165**	483
Net (decrease) increase	**(130)**	139	**63**	286
Cash and cash equivalents, end of period	**625**	699	**625**	699

For a discussion regarding cash flow provided by operating activities and FFO Interest Coverage, refer to the discussion under the *Highlights* section.

Investing Activities

Cash flow used in investing activities during the second quarter of 2014 decreased by $46 million compared to the same quarter in 2013. This decrease was primarily due to lower capital expenditures for the Lower Mattagami River project and the Atikokan Biomass Conversion project. This was partially offset by higher expenditures for the Darlington Refurbishment project.

Cash flow used in investing activities during the six months ended June 30, 2014 decreased by $54 million compared to the same period in 2013. The decrease was primarily due to lower capital expenditures for:

- the Lower Mattagami River project as a result of two incremental units being declared in-service in 2014
- the Niagara Tunnel project, which was declared in-service in March 2013
- the Atikokan Biomass Conversion project
- partially offset by higher expenditures for the Darlington Refurbishment project.

OPG's forecast capital expenditures for 2014 are approximately $1.7 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 term tranches. In the second quarter of 2014, OPG renewed and extended both tranches to May 2019. As at June 30, 2014, there were no outstanding borrowings under the bank credit facility.

As at June 30, 2014, OPG maintained $25 million of short-term, uncommitted overdraft facilities, and $374 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 general corporate purposes. As at June 30, 2014, a total of $328 million of Letters of Credit had been issued. This included $302 million for the supplementary pension plans, $25 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement, which expires November 30, 2014, to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. In the second quarter of 2014, the maximum co-ownership interest that can be sold under the agreement was reduced to $200 million from $250 million. As at June 30, 2014, of the $302 million of Letters of Credit issued for the supplementary pension plans, $80 million were issued under this agreement.

OPG also maintains a Niagara Tunnel project credit facility with the OEFC for an amount up to $1.6 billion. As at June 30, 2014, advances under this facility were $1,065 million, with no new borrowing during the second quarter of 2014. OPG's borrowing under this facility is limited to the cost of the project. This credit facility expires on December 31, 2014.

The Lower Mattagami Energy Limited Partnership (LME) maintains a $600 million bank credit facility to support the funding requirements of the Lower Mattagami River project. The facility consists of two tranches. The first tranche of $300 million matures in August 2018. In the third quarter of 2014, OPG expects to extend the maturity of this tranche to August 2019. The second tranche of $300 million matures in August 2015. As at June 30, 2014, there was no commercial paper outstanding under this program. In June 2014, LME issued senior notes totalling $200 million with a maturity date of 2024. The effective interest rate for these notes was 3.5 percent and the coupon interest rate was 3.4 percent.

As at June 30, 2014, OPG's long-term debt outstanding was $5,781 million, including $306 million due within one year. OPG entered into an agreement with the OEFC in December 2013 for a $500 million general corporate credit facility. As at June 30, 2014, there were no outstanding borrowings under this credit facility. This credit facility expires on December 31, 2014.

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 June 30 2014	As At December 31 2013
Property, plant and equipment - net	**17,178**	16,738
The increase was primarily due to an increase in construction in progress for the refurbishment of the Darlington Nuclear GS and the Lower Mattagami River project. This was partially offset by depreciation expense for the six months ended June 30, 2014.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**13,986**	13,496
The increase was primarily due to earnings on the Nuclear Funds and contributions to the Used Fuel Fund, partially offset by reimbursements of expenditures on nuclear fixed asset removal and nuclear waste management.		
Fixed asset removal and nuclear waste management liabilities	**16,648**	16,257
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.		
Long-term accounts payable and accrued charges	**471**	653
The decrease was primarily due to a decrease of $164 million in the fair value of the derivative liability embedded in the Bruce Lease. The decrease in the fair value of the derivative liability was offset by the Bruce Lease Net Revenues Variance Account.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities that OPG undertakes include 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 are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2013. A discussion of changes in accounting policies is included in OPG's interim consolidated financial statements for the second quarter of 2014 under the heading, *Changes in Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2013 annual MD&A.

Exemptive Relief for Reporting under US GAAP

During the first quarter of 2014, OPG received exemptive relief from the OSC requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP without becoming a Securities and Exchange Commission registrant, or issuing public debt. The exemption will terminate on the earliest of the following:

- January 1, 2019
- the financial year that commences after OPG ceases to have activities subject to rate regulation
- the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within International Financial Reporting Standards (IFRS) specific to entities with rate-regulated activities.

This exemption replaces the exemptive relief received by OPG from the OSC in December 2011. The 2011 exemption allowed OPG to file consolidated financial statements based on US GAAP for financial years that began on or after January 1, 2012, but before January 1, 2015.

As a result of OPG's 2011 decision to adopt US GAAP, as required by the FAA regulation, OPG's plan to convert to IFRS, effective January 1, 2012, was discontinued. Prior to the adoption of US GAAP as the basis for OPG's financial reporting, the Company had planned to adopt IFRS effective January 1, 2012. OPG had substantively completed its IFRS conversion project, which included separate diagnostic, development, and implementation phases, when it suspended the project and began the evaluation of converting to US GAAP in the fourth quarter of 2011. If a future transition to IFRS is required, conversion work can effectively be restarted with sufficient lead time to evaluate and conclude on changes that occurred subsequent to the decision to suspend the project.

Regulatory Assets Related to Newly Regulated Hydroelectric Facilities

Forty-eight of OPG's previously unregulated hydroelectric facilities were prescribed for rate regulation effective July 1, 2014. OPG expects to recognize additional regulatory assets related to deferred income taxes and unamortized amounts recorded in accumulated other comprehensive income (AOCI) in respect of pension and OPEB obligations in the third quarter of 2014. The recognition of the increase in regulatory assets related to deferred income taxes expected to be recovered from customers through future regulated prices is expected to result in an extraordinary gain of approximately $250 million in the consolidated statements of income. The additional regulatory assets related to pension and OPEB obligations are expected to result in an increase of approximately $200 million in other comprehensive income, net of income taxes.

Recent Accounting Pronouncements

<u>Revenue from Contracts with Customers</u>

On May 28, 2014, the Financial Accounting Standards Board (FASB) and the International Accounting Standards Board issued their final standard on revenue from contracts with customers. The FASB issued the standard as Accounting Standards Update 2014-09, *Revenue from Contracts with Customers* codified as Topic 606. The standard outlines a single comprehensive model to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. The standard will be effective for OPG's 2017 fiscal year, including interim periods within that reporting period. In applying the standard, entities would have the option between two retrospective methods. OPG has not selected an adoption method and is currently assessing the impact of this new standard on its consolidated financial statements.

RISK MANAGEMENT

This risk management disclosure should be read in conjunction with the *Risk Management* section included in OPG's 2013 annual MD&A which provides a detailed discussion of OPG's governance structure, inherent risks, and activities associated with identifying and managing risks. The following discussion provides an update of OPG's risk management activities.

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 majority of this exposure should be eliminated with the implementation of a regulated price for 48 of OPG's previously unregulated hydroelectric facilities, which were prescribed for rate regulation in accordance with amended *Ontario Regulation 53/05*, effective July 1, 2014.

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

	2014 [1]	**2015**	**2016**
Estimated generation output hedged [2]	89%	98%	100%
Estimated fuel requirements hedged [3]	81%	71%	67%
Estimated nitric oxide emission requirement hedged [4]	100%	100%	100%
Estimated sulphur dioxide emission requirement hedged [4]	100%	100%	100%

[1] Includes forecast for the remainder of the year.

[2] Represents the portion of megawatt-hours of expected future generation production which is subject to regulated prices established by the OEB, OEFC, and OPA, or other electricity contracts which are used as hedges.

[3] Represents the approximate portion of megawatt-hours of expected generation production and year-end inventory targets from each type of facility (nuclear and thermal) 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.

[4] 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 Regulation 397/01*.

Foreign Exchange and Interest Rate Markets

OPG's earnings and cash flows can be affected by movements in the US dollar relative to the Canadian dollar, and by prevailing interest rates on its borrowings and investment programs.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations are primarily denominated in US dollars. In addition, the market price of electricity in Ontario is influenced by the exchange rate as a result of the interaction between the Ontario and neighbouring US interconnected electricity markets. The Ontario electricity spot market is also influenced by US dollar denominated commodity prices for natural gas which is used in electricity generation. To manage this risk, OPG employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at June 30, 2014, OPG did not have any foreign exchange contracts outstanding.

The majority of OPG’s existing debt is at fixed interest rates. Interest rate risk arises with the need to refinance existing debt and/or undertake new financing. 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 June 30, 2014, OPG did not have any interest rate swap contracts outstanding.

Trading

OPG’s financial performance can be 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. One of the metrics used to measure the financial risk of this trading activity is Value at Risk (VaR). For the second quarter of 2014, the utilization of VaR averaged $0.7 million, compared to an average of $0.2 million for the second quarter of 2013. The increase in VaR utilization was primarily due to increased positions of less than one year in duration in both the Ontario and US energy markets, with the intention of capturing the renewed trading opportunities between the two markets.

Credit

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

OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition 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 June 30, 2014 was $387 million, including $361 million to the Independent Electricity System Operator. Over 95 percent of the remaining $26 million exposure is related to investment grade counterparties.

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 controls 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

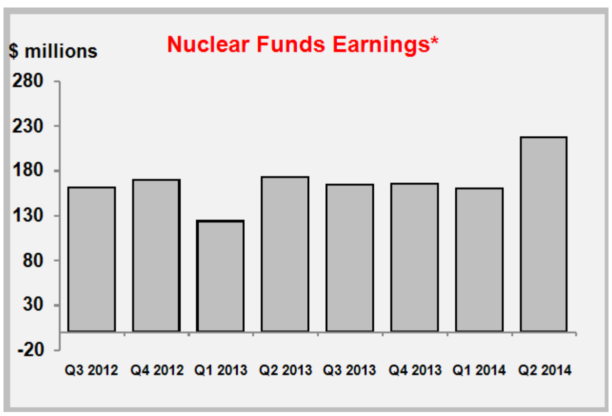
The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters. This financial information has been prepared in accordance with US GAAP.

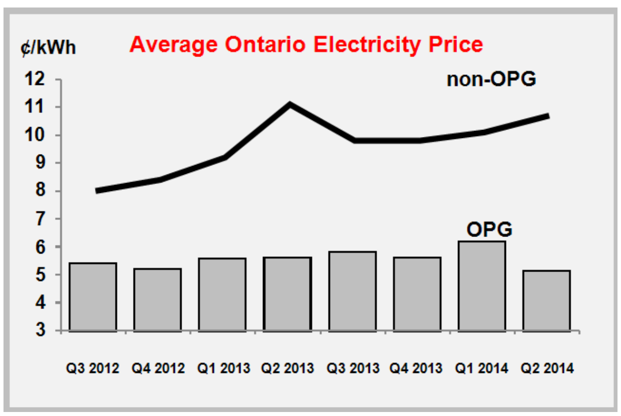
(millions of dollars – except where noted) (unaudited)	June 30 2014	March 31 2014	December 31 2013	September 30 2013
Revenue	**1,098**	1,387	1,174	1,244
Net income attributable to the Province	**115**	242	4	30
Net income per common share *(dollars)*	**$0.45**	$0.94	$0.02	$0.12

(millions of dollars – except where noted) (unaudited)	June 30 2013	March 31 2013	December 31 2012	September 30 2012
Revenue	1,190	1,255	1,195	1,213
Net income attributable to the Province	73	28	31	139
Net income per common share *(dollars)*	$0.28	$0.11	$0.12	$0.54

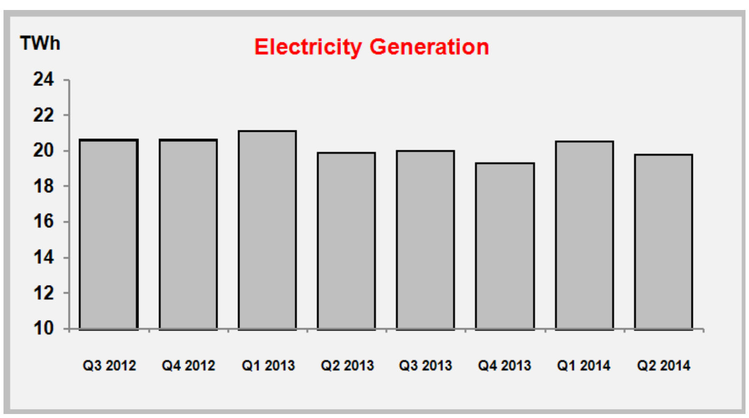
Trends

OPG's quarterly results are affected 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. In addition to average revenue and generation volume, OPG's income is affected by earnings from the Nuclear Funds.





*net of regulatory variance account



Items which affected net income during 2014 are described below.

- During the first quarter of 2014, increase in revenue of $132 million primarily as a result of higher electricity spot market prices and trading revenue, partially offset by lower rate riders in 2014
- During the first quarter of 2014, lower earnings of $11 million from the Nanticoke GS and the Lambton GS mainly as a result of ending coal-fired generation at these stations in 2013.

Additional items which affected net income prior to 2014 are described in OPG's 2013 annual MD&A.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A and unaudited interim consolidated financial statements. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A, interim consolidated financial statements and the notes thereto utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present a measure consistent with the corporate strategy to operate on a financially sustainable basis. These non-GAAP financial measures have not been presented as an alternative to net income in accordance with US GAAP, but as an indicator of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE** is defined as net income attributable to the Province divided by average equity attributable to the Province excluding AOCI, for the period. ROE is measured over a 12-month period. The definition of ROE was refined as of January 1, 2014 as a result of the non-controlling interest established, which reflects equity contributions made by the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation to the Lower Mattagami Limited Partnership in the first quarter of 2014.

(2) **FFO Interest Coverage** is defined as FFO before interest divided by Adjusted Interest Expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted Interest Expense includes net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and interest on pension and OPEB projected benefit obligations less expected return on pension plan assets for the period.

FFO Interest Coverage is measured over a period of twelve months and is calculated as follows:

	For the twelve months ended	
(millions of dollars – except where noted)	**June 30 2014**	**December 31 2013**
FFO before interest		
Cash flow provided by operating activities	**1,215**	1,174
Add: Interest paid	**266**	255
Less: Interest capitalized to fixed and intangible assets	**(132)**	(127)
Add: Changes to non-cash working capital balances	**(207)**	(239)
FFO before interest	**1,142**	1,063
Adjusted Interest Expense		
Net interest expense	**64**	86
Add: Interest income	**11**	10
Add: Interest capitalized to fixed and intangible assets	**132**	127
Add: Interest related to regulatory assets and liabilities	**89**	66
Add: Interest on pension and OPEB projected benefit obligation less expected return on pension plan assets	**134**	92
Adjusted Interest Expense	**430**	381
FFO Interest Coverage *(times)*	**2.7**	2.8

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

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

Additional information about OPG, including its Annual Information Form, annual MD&A, and audited annual consolidated financial statements as at and for the year ended December 31, 2013 and notes thereto can be found on SEDAR at www.sedar.com.

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www.sedar.com

ONTARIO POWER GENERATION INC.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

JUNE 30, 2014

INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars except where noted)	**Three Months Ended June 30 2014**	**Three Months Ended June 30 2013**	**Six Months Ended June 30 2014**	**Six Months Ended June 30 2013**
Revenue *(Note 12)*	**1,098**	1,190	**2,485**	2,445
Fuel expense *(Note 12)*	**154**	172	**303**	355
Gross margin *(Note 12)*	**944**	1,018	**2,182**	2,090
Expenses				
Operations, maintenance and administration *(Note 12)*	**666**	643	**1,336**	1,343
Depreciation and amortization	**181**	242	**362**	484
Accretion on fixed asset removal and nuclear waste management liabilities	**195**	190	**391**	379
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(217)**	(173)	**(377)**	(297)
Property and capital taxes	**(1)**	14	**10**	29
Income from investments subject to significant influence	**(10)**	(9)	**(23)**	(19)
Restructuring *(Note 16)*	**10**	-	**12**	2
	824	907	**1,711**	1,921
Income before other loss (income), interest, and income taxes	**120**	111	**471**	169
Other loss (income)	**1**	(4)	**2**	(3)
Income before interest and income taxes	**119**	115	**469**	172
Net interest expense *(Note 5)*	**11**	20	**23**	45
Income before income taxes	**108**	95	**446**	127
Income tax (recovery) expense	**(8)**	22	**87**	26
Net income	**116**	73	**359**	101
Net income attributable to the Province	**115**	73	**357**	101
Net income attributable to non-controlling interests *(Note 17)*	**1**	-	**2**	-
Basic and diluted net income per common share *(dollars)*	**0.45**	0.28	**1.39**	0.39
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 COMPREHENSIVE INCOME (UNAUDITED)

(millions of dollars)	Three Months Ended June 30 2014	Three Months Ended June 30 2013	Six Months Ended June 30 2014	Six Months Ended June 30 2013
Net income	**116**	73	**359**	101
Other comprehensive income, net of income taxes *(Note 7)*				
Net (loss) gain on derivatives designated as cash flow hedges [1]	**(2)**	9	**(3)**	11
Reclassification to income of losses from cash flow hedges [2]	**2**	-	**5**	7
Reclassification to income of amounts related to pension and other post-employment benefits [3]	**10**	12	**19**	22
Other comprehensive income for the period	**10**	21	**21**	40
Comprehensive income	**126**	94	**380**	141
Comprehensive income attributable to the Province	**125**	94	**378**	141
Comprehensive income attributable to non-controlling interests	**1**	-	**2**	-

[1] Net of income tax recoveries of $1 million and income tax expense $2 million for the three months ended June 30, 2014 and 2013, respectively. Net of income tax recoveries of $2 million and income tax expense of $3 million for the six months ended June 30, 2014 and 2013, respectively.

[2] Net of income tax expense of $1 million for the three months ended June 30, 2014 and 2013, respectively. Net of income tax expense of $1 million for the six months ended June 30, 2014 and 2013, respectively.

[3] Net of income tax expenses of $2 million and $3 million for the three months ended June 30, 2014 and 2013, respectively. Net of income tax expenses of $6 million and $7 million for the six months ended June 30, 2014 and 2013, respectively.

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Six Months Ended June 30 *(millions of dollars)*	2014	2013
Operating activities		
Net income	**359**	101
Adjust for non-cash items:		
Depreciation and amortization	**362**	484
Accretion on fixed asset removal and nuclear waste management liabilities	**391**	379
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(377)**	(297)
Pension and other post-employment benefit costs *(Note 8)*	**228**	235
Deferred income taxes and other accrued charges	**43**	6
Provision for restructuring *(Note 16)*	**9**	2
Mark-to-market on derivative instruments	**(170)**	10
Provision for used nuclear fuel and low and intermediate level waste	**54**	50
Regulatory assets and liabilities	**72**	(109)
Provision for materials and supplies	**11**	9
Other	**(12)**	(19)
	970	851
Contributions to nuclear fixed asset removal and nuclear waste management funds	**(69)**	(88)
Expenditures on fixed asset removal and nuclear waste management	**(97)**	(101)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management	**43**	46
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(206)**	(205)
Expenditures on restructuring *(Note 16)*	**(16)**	(1)
Net changes to other long-term assets and liabilities	**21**	71
Net changes to non-cash working capital balances *(Note 13)*	**(13)**	19
Cash flow provided by operating activities	**633**	592
Investing activities		
Investment in property, plant and equipment and intangible assets	**(735)**	(789)
Cash flow used in investing activities	**(735)**	(789)
Financing activities		
Issuance of long-term debt	**200**	315
Repayment of long-term debt	**(2)**	(2)
Distribution to non-controlling interests *(Note 17)*	**(1)**	-
Issuance of short-term notes	**912**	560
Repayment of short-term notes	**(944)**	(390)
Cash flow provided by financing activities	**165**	483
Net increase in cash and cash equivalents	**63**	286
Cash and cash equivalents, beginning of period	**562**	413
Cash and cash equivalents, end of period	**625**	699

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**June 30 2014**	**December 31 2013**
Assets		
Current assets		
Cash and cash equivalents	**625**	562
Receivables from related parties *(Note 14)*	**364**	402
Other accounts receivable and prepaid expenses	**174**	148
Nuclear fixed asset removal and nuclear waste management funds *(Notes 6 and 12)*	**15**	25
Fuel inventory *(Note 12)*	**366**	390
Materials and supplies *(Note 12)*	**94**	95
Regulatory assets *(Note 3)*	**153**	306
Income taxes recoverable	**-**	51
Deferred income taxes	**22**	-
	1,813	1,979
Property, plant and equipment *(Note 12)*	**25,157**	24,441
Less: accumulated depreciation	**7,979**	7,703
	17,178	16,738
Intangible assets *(Note 12)*	**418**	402
Less: accumulated amortization	**350**	343
	68	59
Other assets		
Nuclear fixed asset removal and nuclear waste management funds *(Notes 6 and 12)*	**13,971**	13,471
Long-term materials and supplies *(Note 12)*	**337**	330
Regulatory assets *(Note 3)*	**5,088**	5,094
Investments subject to significant influence *(Note 15)*	**354**	359
Other long-term assets	**62**	61
	19,812	19,315
	38,871	38,091

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**June 30 2014**	**December 31 2013**
Liabilities		
Current liabilities		
Accounts payable and accrued charges	**891**	1,026
Deferred revenue due within one year	**12**	12
Long-term debt due within one year *(Note 4)*	**306**	5
Short-term debt *(Note 5)*	**-**	32
Regulatory liabilities *(Note 3)*	**8**	16
Income taxes payable	**26**	-
Deferred income taxes	**-**	14
	1,243	1,105
Long-term debt *(Note 4)*	**5,475**	5,620
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Notes 6 and 12)*	**16,648**	16,257
Pension liabilities	**2,725**	2,741
Other post-retirement benefit liabilities	**2,682**	2,628
Long-term accounts payable and accrued charges	**471**	653
Deferred revenue	**196**	180
Deferred income taxes	**655**	565
Regulatory liabilities *(Note 3)*	**11**	8
	23,388	23,032
Equity		
Common shares [1]	**5,126**	5,126
Retained earnings	**4,249**	3,892
Accumulated other comprehensive loss *(Note 7)*	**(663)**	(684)
Equity attributable to the Province	**8,712**	8,334
Equity attributable to non-controlling interests *(Note 17)*	**53**	-
Total Equity	**8,765**	8,334
	38,871	38,091

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at June 30, 2014 and December 31, 2013.

Commitments and Contingencies *(Notes 4, 8, 10 and 11)*

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (UNAUDITED)

Six Months Ended June 30 *(millions of dollars)*	**2014**	**2013**
Common shares	**5,126**	5,126
Retained earnings		
Balance at beginning of period	**3,892**	3,757
Net income attributable to the Province	**357**	101
Balance at end of period	**4,249**	3,858
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of period	**(684)**	(979)
Other comprehensive income	**21**	40
Balance at end of period	**(663)**	(939)
Equity attributable to the Province	**8,712**	8,045
Equity attributable to non-controlling interests *(Note 17)*		
Balance at beginning of period	**-**	-
Capital contribution from non-controlling interests	**53**	-
Distribution to non-controlling interests	**(2)**	-
Net income attributable to non-controlling interests	**2**	-
Balance at end of period	**53**	-
Total equity	**8,765**	8,045

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

For the three and six months ended June 30, 2014 and 2013

1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three and six months ended June 30, 2014 include the accounts of Ontario Power Generation Inc. (OPG or Company) and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control and attributes the results to its sole shareholder, the Province of Ontario (Province). Interests owned by other parties are reflected as non-controlling interests. These interim consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP) and the rules and regulations of the United States Securities and Exchange Commission for interim financial statements. These interim statements do not contain all of the disclosures required by US GAAP for annual financial statements. Accordingly, they should be read in conjunction with the annual consolidated financial statements of the Company as at and for the year ended December 31, 2013. All dollar amounts are presented in Canadian dollars.

Certain of the 2013 comparative amounts have been reclassified from financial statements previously presented to conform to the 2014 interim consolidated financial statement presentation.

Effective January 1, 2014, OPG revised the composition of its reportable business segments to reflect changes in its generation portfolio and its internal reporting. Information for the comparative period has been adjusted to reflect the changes to the reportable business segments. For further discussion, refer to Note 12, *Business Segments*.

Use of Management Estimates

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the interim consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Management evaluates the Company's estimates on an ongoing basis based on historical experience, current conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefits (OPEB), asset retirement obligations, income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of derivative instruments, depreciation and amortization, and inventories. Actual results may differ significantly from these estimates.

Seasonal Operations

OPG's quarterly results are affected 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. Regulated prices for most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that OPG operates, cost recovery contracts and energy supply agreements, and OPG's hedging strategies significantly reduce the impact of seasonal price fluctuations on the results of operations.

2. CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

Investment Companies

Effective January 1, 2014, OPG adopted the updated Accounting Standards Codification (ASC) Topic 946, *Financial Services – Investment Companies*. Based on the amended scope of the standard, certain entities and funds including the Decommissioning Segregated Fund (Decommissioning Fund) and the Used Fuel Segregated Fund (Used Fuel Fund) (together the Nuclear Funds) are treated as investment companies for accounting purposes. As the investments of these funds are already recorded at fair value, there were no measurement differences upon adoption of this update. OPG has provided the required additional disclosures in Note 6 of these interim consolidated financial statements.

Regulatory Assets Related to Newly Regulated Hydroelectric Facilities

Forty-eight of OPG's previously unregulated hydroelectric facilities were prescribed for rate regulation effective July 1, 2014. OPG expects to recognize additional regulatory assets related to deferred income taxes and unamortized amounts recorded in accumulated other comprehensive income in respect of pension and OPEB obligations in the third quarter of 2014. The recognition of the increase in regulatory assets related to deferred income taxes expected to be recovered from customers through future regulated prices is expected to result in an extraordinary gain of approximately $250 million in the consolidated statements of income. The additional regulatory assets related to pension and OPEB obligations are expected to result in an increase of approximately $200 million in other comprehensive income, net of income taxes.

Recent Accounting Pronouncements

Revenue from Contracts with Customers

On May 28, 2014, the Financial Accounting Standards Board (FASB) and the International Accounting Standards Board issued their final standard on revenue from contracts with customers. The FASB issued the standard as Accounting Standards Update 2014-09, *Revenue from Contracts with Customers* codified as ASC Topic 606. The standard outlines a single comprehensive model to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. The standard will be effective for OPG's 2017 fiscal year, including interim periods within that reporting period. In applying the standard, entities would have the option between two retrospective methods. OPG has not selected an adoption method and is currently assessing the impact of this new standard on its consolidated financial statements.

3. REGULATORY ASSETS AND LIABILITIES

The regulatory assets and liabilities recorded as at June 30, 2014 and December 31, 2013 are as follows:

(millions of dollars)	**June 30 2014**	**December 31 2013**
Regulatory assets		
Variance and deferral accounts as authorized by the Ontario Energy Board (OEB)		
Pension and OPEB Cost Variance Account	**840**	667
Bruce Lease Net Revenues Variance Account	**211**	353
Nuclear Liability Deferral Account	**277**	254
Capacity Refurbishment Variance Account	**156**	100
Tax Loss Variance Account	**64**	124
Nuclear Development Variance Account	**58**	57
Other variance and deferral accounts	**114**	128
	1,720	1,683
Pension and OPEB Regulatory Asset *(Note 8)*	**3,048**	3,158
Deferred income taxes	**473**	559
Total regulatory assets	**5,241**	5,400
Less: current portion	**153**	306
Non-current regulatory assets	**5,088**	5,094
Regulatory liabilities		
Variance and deferral accounts as authorized by the OEB		
Other variance and deferral accounts	**19**	24
Total regulatory liabilities	**19**	24
Less: current portion	**8**	16
Non-current regulatory liabilities	**11**	8

As at June 30, 2014 and December 31, 2013, regulatory assets for other variance and deferral accounts included the Nuclear Deferral and Variance Over/Under Recovery Variance Account, the Hydroelectric Surplus Baseload Generation Variance Account, the Hydroelectric Water Conditions Variance Account, the Impact for USGAAP Deferral Account, and other variance accounts authorized by the OEB. As at June 30, 2014 and December 31, 2013, regulatory liabilities for other variance and deferral accounts included the Income and Other Taxes Variance Account and other variance accounts authorized by the OEB.

4. LONG-TERM DEBT

Long-term debt consists of the following:

(millions of dollars)	June 30 2014	December 31 2013
Notes payable to the Ontario Electricity Financial Corporation (OEFC)	**3,965**	3,965
UMH Energy Partnership debt	**191**	193
Lower Mattagami Energy Limited Partnership debt *(Note 17)*	**1,625**	1,467
	5,781	5,625
Less: due within one year	**306**	5
Long-term debt	**5,475**	5,620

In June 2014, the Lower Mattagami Energy Limited Partnership (LME) issued senior notes totalling $200 million with a maturity date of 2024. The effective interest rate for these notes was 3.5 percent and the coupon interest rate was 3.4 percent.

5. SHORT-TERM DEBT AND NET INTEREST EXPENSE

LME maintains a $600 million bank credit facility to support the funding requirements of the Lower Mattagami River project. The facility consists of two tranches. The first tranche of $300 million matures in August 2018. The second tranche of $300 million matures in August 2015. As at June 30, 2014, there was no commercial paper outstanding under this program (December 31, 2013 – $32 million).

The following table summarizes net interest expense:

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	2014	2013	2014	2013
Interest on long-term debt	**72**	70	**144**	136
Interest on short-term debt	**-**	1	**1**	2
Interest income	**(2)**	(2)	**(5)**	(4)
Interest capitalized to property, plant and equipment and intangible assets	**(36)**	(26)	**(71)**	(66)
Interest related to regulatory assets and liabilities [1]	**(23)**	(23)	**(46)**	(23)
Net interest expense	**11**	20	**23**	45

[1] Includes interest to recognize the cost of financing related to regulatory assets and liabilities and interest deferred in the Capacity Refurbishment Variance Account and the Bruce Lease Net Revenues Variance Account.

6. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as at June 30, 2014 and December 31, 2013 consist of the following:

(millions of dollars)	June 30 2014	December 31 2013
Liability for nuclear used fuel management	**10,207**	9,957
Liability for nuclear decommissioning and low and intermediate level waste management	**6,081**	5,946
Liability for non-nuclear fixed asset removal	**360**	354
Fixed asset removal and nuclear waste management liabilities	**16,648**	16,257

Nuclear Funds

Beginning January 1, 2014, the Company applied ASC 946 for all investments owned by the Decommissioning Fund and the Used Fuel Fund. OPG's consolidated financial statements retained investment company accounting for the Nuclear Funds. The adoption of investment company accounting for the Nuclear Funds did not result in an effect on net income or change in net assets from operations as investments held by OPG's Nuclear Funds continue to be recorded at fair value.

The policy for distinguishing the nature and type of investments made by OPG which retain investment company accounting from other investments made by OPG is that these investments have the attributes of an investment company in accordance with ASC 946 as amended by Accounting Standards Update 2013-08, *Financial Services – Investment Companies (Topic 946): Amendments to the Scope, Measurement, and Disclosure Requirements.*

The historical cost, gross unrealized aggregate appreciation and depreciation of investments, gross unrealized foreign exchange gains and fair value of the Nuclear Funds as at June 30, 2014 are summarized as follows:

(millions of dollars)	Decommissioning Fund	Used Fuel Fund [1]	Total
Historical cost	**5,980**	**7,850**	**13,830**
Unrealized gains			
Gross unrealized aggregate appreciation	**1,151**	**1,369**	**2,520**
Gross unrealized aggregate depreciation	**(73)**	**(72)**	**(145)**
Gross unrealized foreign exchange gains	**14**	**30**	**44**
	7,072	**9,177**	**16,249**
Due to Province	**(972)**	**(1,291)**	**(2,263)**
Total fair value	**6,100**	**7,886**	**13,986**
Less: current portion	**5**	**10**	**15**
Non-current fair value	**6,095**	**7,876**	**13,971**

[1] The Ontario NFWA Trust represented $2,984 million as at June 30, 2014 of the Used Fuel Fund on a fair value basis.

The historical cost, gross unrealized aggregate appreciation and depreciation of investments, gross unrealized foreign exchange gains and fair value of the Nuclear Funds as at December 31, 2013 are summarized as follows:

(millions of dollars)	**Decommissioning Fund**	**Used Fuel Fund [1]**	**Total**
Historical cost	5,571	7,240	12,811
Unrealized gains			
Gross unrealized aggregate appreciation	1,111	1,365	2,476
Gross unrealized aggregate depreciation	(118)	(136)	(254)
Gross unrealized foreign exchange gains	27	50	77
	6,591	8,519	15,110
Due to Province	(624)	(990)	(1,614)
Fair value	5,967	7,529	13,496
Less: current portion	12	13	25
Non-current fair value	5,955	7,516	13,471

[1] The Ontario NFWA Trust represented $2,668 million as at December 31, 2013 of the Used Fuel Fund on a fair value basis.

Net realized and unrealized gains or losses from investments for the six months ended June 30, 2014 are summarized as follows:

(millions of dollars)	**Decommissioning Fund**	**Used Fuel Fund**	**Total**
Net realized gains			
Realized gains	**320**	**434**	**754**
Realized foreign exchange gains	**-**	**-**	**-**
Net realized gains	**320**	**434**	**754**
Net unrealized gains			
Unrealized gains	**85**	**68**	**153**
Unrealized foreign exchange losses	**(13)**	**(20)**	**(33)**
Net unrealized gains	**72**	**48**	**120**

Net realized and unrealized gains or losses from investments for the six months ended June 30, 2013 are summarized as follows:

(millions of dollars)	**Decommissioning Fund**	**Used Fuel Fund**	**Total**
Net realized gains			
Realized gains	93	129	222
Realized foreign exchange losses	(7)	(4)	(11)
Net realized gains	86	125	211
Net unrealized gains			
Unrealized gains	19	51	70
Unrealized foreign exchange gains	54	55	109
Net unrealized gains	73	106	179

7. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), net of income taxes, are as follows:

	Six Months Ended June 30, 2014		
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges** [1]	**Pension and OPEB** [1]	**Total** [1]
AOCL, beginning of period	**(129)**	**(555)**	**(684)**
Net loss on cash flow hedges	**(3)**	**-**	**(3)**
Amounts reclassified from AOCL	**5**	**19**	**24**
Other comprehensive income for the period	**2**	**19**	**21**
AOCL, end of period	**(127)**	**(536)**	**(663)**

[1] All amounts are net of income taxes.

	Six Months Ended June 30, 2013		
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges** [1]	**Pension and OPEB** [1]	**Total** [1]
AOCL, beginning of period	(156)	(823)	(979)
Net gain on cash flow hedges	11	-	11
Amounts reclassified from AOCL	7	22	29
Other comprehensive income for the period	18	22	40
AOCL, end of period	(138)	(801)	(939)

[1] All amounts are net of income taxes.

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and six months ended June 30, 2014 are as follows:

	Amount Reclassified from AOCL		
(millions of dollars)	**Three Months Ended June 30, 2014**	**Six Months Ended June 30, 2014**	**Statement of Income Line Item**
Amortization of losses from cash flow hedges			
Losses	**3**	**6**	Net interest expense
Income tax expense	**(1)**	**(1)**	
	2	**5**	
Amortization of amounts related to pension and OPEB			
Actuarial gains and past service costs	**12**	**25**	See (1) below
Income tax recoveries	**(2)**	**(6)**	
	10	**19**	
Total reclassifications for the period	**12**	**24**	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 8 for additional details).

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and six months ended June 30, 2013 are as follows:

(millions of dollars)	Amount Reclassified from AOCL Three Months Ended June 30, 2013	Amount Reclassified from AOCL Six Months Ended June 30, 2013	Statement of Income Line Item
Amortization of losses from cash flow hedges			
Losses	1	8	Net interest expense
Income tax expense	(1)	(1)	
	-	7	
Amortization of amounts related to pension and OPEB			
Actuarial gains and past service costs	15	29	See (1) below
Income tax recoveries	(3)	(7)	
	12	22	
Total reclassifications for the period	12	29	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 8 for additional details).

8. PENSION AND OPEB

OPG's total benefit costs for the three months ended June 30, 2014 and 2013 are as follows:

(millions of dollars)	Registered Pension Plans 2014	Registered Pension Plans 2013	Supplementary Pension Plans 2014	Supplementary Pension Plans 2013	OPEB 2014	OPEB 2013
Components of Cost Recognized						
Current service costs	**60**	72	**2**	3	**16**	26
Interest on projected benefit obligation	**164**	148	**3**	3	**33**	34
Expected return on plan assets, net of expenses	**(157)**	(162)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**65**	61	**1**	1	**1**	13
Cost recognized [2]	**132**	119	**6**	7	**50**	73

[1] The amortization of net actuarial loss is recognized as an increase to other comprehensive income. This increase for the three months ended June 30, 2014 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $55 million (three months ended June 30, 2013 – $60 million).

[2] These pension and OPEB costs for the three months ended June 30, 2014 exclude the reduction of costs resulting from the recognition of additions to the regulatory assets for the Pension and OPEB Cost Variance Account of $76 million (three months ended June 30, 2013 – $82 million).

OPG's total benefit costs for the six months ended June 30, 2014 and 2013 are as follows:

	Registered Pension Plans		Supplementary Pension Plans		OPEB	
(millions of dollars)	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**
Components of Cost Recognized						
Current service costs	**119**	145	**4**	5	**32**	52
Interest on projected benefit obligation	**329**	295	**7**	6	**67**	70
Expected return on plan assets, net of expenses	**(314)**	(324)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**130**	122	**2**	3	**3**	25
Cost recognized [2]	**264**	238	**13**	14	**102**	147

[1] The amortization of net actuarial loss is recognized as an increase to other comprehensive income. This increase for the six months ended June 30, 2014 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $110 million (six months ended June 30, 2013 – $121 million).

[2] These pension and OPEB costs for the six months ended June 30, 2014 exclude the reduction of costs resulting from the recognition of additions to the regulatory assets for the Pension and OPEB Cost Variance Account of $151 million (six months ended June 30, 2013 – $164 million).

A new actuarial valuation of the OPG registered pension plan was completed as of January 1, 2014 and was filed with the Financial Services Commission of Ontario in June 2014.

9. DERIVATIVES

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

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt and/or undertake new financing. 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 financing.

LME has 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 River project.

Electricity price risk for the Company is the potential for adverse movements in the market price of electricity. Exposure to electricity price risk is reduced as a result of regulated prices and other contractual arrangements for a significant portion of OPG's business. The majority of this exposure should be mitigated with the implementation of a regulated price for OPG's 48 hydroelectric stations which were prescribed for rate regulation effective July 1, 2014.

The conditional reduction to revenue in the future, embedded in the terms of the Bruce Power lease agreement (Bruce Lease), is treated as a derivative. Assumptions related to future electricity prices impact the valuation of the derivative liability embedded in the Bruce Lease.

OPG's foreign exchange exposure is attributable to two primary factors: United States (US) dollar denominated transactions such as the purchase of fuels; and the influence of US dollar denominated commodity prices on Ontario electricity market prices. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when necessary, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the Independent Electricity System Operator (IESO) administered spot market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at June 30, 2014 was less than $1 million.

The following is a summary of OPG's derivative instruments:

(millions of dollars except where noted)	**Notional Quantity**	**Terms**	**Fair Value**	**Balance Sheet Line Item**
As at June 30, 2014				
Derivative embedded in the Bruce Lease	**n/a**	**6 years**	**(182)**	Long-term accounts payable and accrued charges
Other derivative instruments	**various**	**various**	**10**	Various
Total derivatives			**(172)**	

(millions of dollars except where noted)	**Notional Quantity**	**Terms**	**Fair Value**	**Balance Sheet Line Item**
As at December 31, 2013				
Derivative embedded in the Bruce Lease	n/a	6 years	(346)	Long-term accounts payable and accrued charges
Other derivative instruments	various	various	(8)	Various
Total derivatives			(354)	

Existing net losses of $20 million deferred in AOCL as at June 30, 2014 are expected to be reclassified to net income within the next 12 months.

10. FAIR VALUE MEASUREMENTS

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.

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial assets and liabilities into three levels based on the significance of inputs used in measuring the fair value of the financial assets and liabilities. The level within which the financial asset or liability is classified is determined based on the attribute of significance to the inputs to the fair value measurement. The fair value hierarchy has the following levels:

- Level 1: Valuation of inputs is based on unadjusted quoted market prices observed in active markets for identical assets or liabilities.
- Level 2: Valuation is based on inputs other than quoted prices under Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3: Valuation is based on inputs for the asset or liability that are not based on observable market data.

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 current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments.

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. The estimation of fair value 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. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. 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. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques were used to value these instruments. Significant Level 3 inputs include recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

Transfers into, out of, or between levels are deemed to have occurred on the date of the event or change in circumstances that caused the transfer to occur.

The Company is required to determine the fair value of all its financial instruments. The following is a summary of OPG's financial instruments as at June 30, 2014 and December 31, 2013:

(millions of dollars)	**Fair Value**	**Carrying Value** [1]	**Balance Sheet Line Item**
As at June 30, 2014			
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	**13,986**	**13,986**	Nuclear fixed asset removal and nuclear waste management funds
Payable related to cash flow hedges	**(67)**	**(67)**	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	**(182)**	**(182)**	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	**(6,304)**	**(5,781)**	Long-term debt
Other financial instruments	**18**	**18**	Various
As at December 31, 2013			
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	13,496	13,496	Nuclear fixed asset removal and nuclear waste management funds
Payable related to cash flow hedges	(56)	(56)	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	(346)	(346)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	(5,955)	(5,625)	Long-term debt
Other financial instruments	1	1	Various

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other accounts receivable and accounts payable and accrued charges approximate their fair value due to the immediate or short-term maturity of these financial instruments.

The fair value of long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

The following tables present financial assets and liabilities measured at fair value in accordance with the fair value hierarchy as at June 30, 2014 and December 31, 2013:

	June 30, 2014			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Decommissioning Fund	**3,084**	**2,724**	**292**	**6,100**
Used Fuel Fund	**605**	**7,229**	**52**	**7,886**
Other financial instruments	**3**	**8**	**19**	**30**
Total	**3,692**	**9,961**	**363**	**14,016**
Liabilities				
Derivative embedded in the Bruce Lease	**-**	**-**	**(182)**	**(182)**
Other financial instruments	**(10)**	**(1)**	**-**	**(11)**
Total	**(10)**	**(1)**	**(182)**	**(193)**
Net assets	**3,682**	**9,960**	**181**	**13,823**

(millions of dollars)	Level 1	December 31, 2013 Level 2	Level 3	Total
Assets				
Decommissioning Fund	3,005	2,715	247	5,967
Used Fuel Fund	526	6,961	42	7,529
Other financial instruments	5	3	12	20
Total	3,536	9,679	301	13,516
Liabilities				
Derivative embedded in the Bruce Lease	-	-	(346)	(346)
Other financial instruments	(8)	(11)	-	(19)
Total	(8)	(11)	(346)	(365)
Net assets (liabilities)	3,528	9,668	(45)	13,151

During the six months ended June 30, 2014, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into and out of Level 3.

The following tables present the changes in OPG's assets and liabilities measured at fair value based on Level 3:

	For the three months ended June 30 2014			
(millions of dollars)	**Decom-missioning Fund**	**Used Fuel Fund**	**Derivative Embedded in the Bruce Lease [1]**	**Other financial instruments**
Opening balance, April 1, 2014	**281**	**49**	**(252)**	**16**
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds [1]	**-**	**-**	**-**	**-**
Unrealized (losses) gains included in revenue	**(4)**	**(1)**	**70**	**-**
Realized losses included in revenue	**-**	**-**	**-**	**(3)**
Purchases	**19**	**4**	**-**	**6**
Settlements	**(4)**	**-**	**-**	**-**
Closing balance, June 30, 2014	**292**	**52**	**(182)**	**19**

[1] Total gains exclude the impact of regulatory assets and liabilities.

	For the six months ended June 30, 2014			
(millions of dollars)	**Decom-missioning Fund**	**Used Fuel Fund**	**Derivative Embedded in the Bruce Lease [1]**	**Other financial instruments**
Opening balance, January 1, 2014	**247**	**42**	**(346)**	**12**
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds [1]	**14**	**2**	**-**	**-**
Unrealized (losses) gains included in revenue	**(4)**	**(1)**	**164**	**-**
Realized losses included in revenue	**-**	**-**	**-**	**(4)**
Purchases	**48**	**9**	**-**	**11**
Sales	**(1)**	**-**	**-**	**-**
Settlements	**(12)**	**-**	**-**	**-**
Closing balance, June 30, 2014	**292**	**52**	**(182)**	**19**

[1] Total gains exclude the impact of regulatory assets and liabilities.

Derivative Embedded in the Bruce Lease

Due to a significant unobservable input used in the pricing model of the Bruce Lease embedded derivative, the measurement of the liability is classified within Level 3.

The following table presents the quantitative information about the Level 3 fair value measurement of the Bruce Lease embedded derivative as at June 30, 2014:

(millions of dollars except where noted)	**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Range**
Derivative embedded in the Bruce Lease	(182)	Option model	Risk Premium[1]	0% - 30%

[1] Represents the range of premiums used in the valuation analysis that OPG has determined market participants would use when pricing the derivative.

The term related to the derivative embedded in the Bruce Lease is based on the remaining service lives, for accounting purposes, for certain units of the Bruce generating stations. OPG's exposure to changes in the fair value of the Bruce Lease embedded derivative is mitigated as part of the OEB regulatory process, since the revenue from the lease of the Bruce generating stations is included in the determination of regulated prices and is subject to the Bruce Lease Net Revenues Variance Account. As such, the pre-tax income statement impact, as a result of changes in the derivative liability, is offset by the pre-tax income statement impact of the Bruce Lease Net Revenues Variance Account.

Nuclear Funds

Nuclear Funds investments classified as Level 3 consist of real estate and infrastructure investments within the alternative investment portfolio. The fair value of the investments within the Nuclear Funds' alternative investment portfolio is determined using appropriate valuation techniques, such as recent arm's length market transactions, reference to current fair values of other instruments that are substantially the same, discounted cash flow analysis, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for the investments. The values may also differ from the prices at which the investments may be sold.

The following are the classes of investments within the Nuclear Funds that are reported on the basis of net asset value as at June 30, 2014:

(millions of dollars except where noted)	**Fair Value**	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice**
Infrastructure	397	322	n/a	n/a
Real Estate	345	317	n/a	n/a
Pooled Funds				
Short-term Investments	17	n/a	Daily	1 - 5 Days
Fixed Income	548	n/a	Daily	1 - 5 Days
Equity	688	n/a	Daily	1 - 5 Days
Total	1,995	639		

The fair value of the above investments is classified as either Level 2 or Level 3.

Infrastructure

This class includes investments in funds whose investment objective is to generate a combination of long-term capital appreciation and current income generally through investments such as energy, transportation, and utilities.

The fair values of investments in this class have been estimated using the Nuclear Funds' ownership interest in partners' capital and/or underlying investments held by subsidiaries of an infrastructure fund.

The investments in the respective infrastructure funds are not redeemable. However, the Nuclear Funds may transfer any of its partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments of the infrastructure funds are liquidated. It is not possible to estimate when the underlying assets of the infrastructure funds will be liquidated. However, the infrastructure funds have a maturity end period ranging from 2019 to 2025.

Real Estate

This class includes investment in institutional-grade real estate property located in Canada. The investment objective is to provide a stable level of income with the opportunity for long-term capital appreciation.

The fair values of the investments in this class have been estimated using the net asset value of the Nuclear Funds' ownership interest in these investments.

The partnership investments are not redeemable. However, the Nuclear Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreement, with prior written consent of the other limited partners. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this class will be liquidated.

Pooled Funds

This class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations and diversified portfolios of Emerging Market listed equity and fixed income securities. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios.

The fair value of the investments in this class has been estimated using the net asset value per share of the investments.

There are no significant restrictions on the ability to sell investments in this class.

11. 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 its 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 defending an arbitration commenced by some of the current owners of Bruce Power L.P. regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power L.P. (the Arbitration). In the second quarter of 2012, the arbitrator released an interim award. The arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The arbitrator determined what elements of the claim British Energy was liable for, but did not award a specific amount in damages as it was found that further evidence from the parties is necessary to quantify the exact amount of the damages. If the parties to the Arbitration cannot agree on the quantum of damages, there will be further proceedings before the arbitrator to determine the amount. British Energy counsel has indicated that the damages payable to the claimants will likely be less than $70 million.

Certain 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. As at June 30, 2014, OPG's environmental liabilities were $15 million (December 31, 2013 – $15 million).

Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at June 30, 2014, the total amount of guarantees OPG provided to these entities was $77 million. OPG may terminate some of these guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. The potential impact of the fair value of these guarantees to income has been estimated as at June 30, 2014 to be negligible. As at June 30, 2014, OPG does not expect to make any payments associated with these guarantees.

Contractual and Commercial Commitments

The Company's contractual obligations and other significant commercial commitments as at June 30, 2014 are as follows:

(millions of dollars)	**2014**	**2015**	**2016**	**2017**	**2018**	**Thereafter**	**Total**
Contractual obligations:							
Fuel supply agreements	90	209	164	143	126	159	891
Contributions under the Ontario Nuclear Funds Agreement (ONFA) [1]	70	143	150	163	193	2,706	3,425
Long-term debt repayment	3	551	273	1,103	398	3,453	5,781
Interest on long-term debt	134	262	249	230	174	2,141	3,190
Unconditional purchase obligations	49	97	8	-	-	-	154
Operating lease obligations	8	16	14	16	13	68	135
Commitments related to Darlington refurbishment [2]	200	-	-	-	-	-	200
Operating licence	20	23	24	24	18	-	109
Pension contributions to the OPG registered pension plan [3]	210	364	370	-	-	-	944
Other	462	53	20	14	4	69	622
	1,246	1,718	1,272	1,693	926	8,596	15,451
Significant commercial commitments:							
Niagara Tunnel	4	-	-	-	-	-	4
Lower Mattagami	104	76	-	-	-	-	180
Atikokan	7	-	-	-	-	-	7
Total	1,361	1,794	1,272	1,693	926	8,596	15,642

[1] Contributions under the ONFA are based on the 2012 ONFA Reference Plan contribution schedule approved in 2012.

[2] Estimated currently committed costs to close the project, including demobilization of project staff and cancellation of existing contracts, and material orders.

[3] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2014. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2017. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2017 for the OPG registered pension plan are excluded due to significant variability in the assumption required to project the timing of future cash flows. The amount of OPG's additional voluntary contribution, if any, is revisited from time to time.

12. BUSINESS SEGMENTS

Effective January 1, 2014, OPG revised the composition of its reportable business segments to reflect changes in its generation portfolio and its internal reporting. These changes primarily reflect 48 of OPG's hydroelectric generating facilities prescribed for rate regulation effective July 1, 2014, and ending the use of coal at the Nanticoke and Lambton generating stations in 2013. OPG's reportable business segments, effective January 1, 2014, are as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and other Non-Generation.

OPG's Regulated – Nuclear Generation and Regulated – Nuclear Waste Management segments are unchanged.

The Regulated – Hydroelectric segment continues to include the results of Sir Adam Beck 1, 2 and Pump generating station (GS), DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. Beginning in the first quarter of 2014, this segment also includes the results of 48 hydroelectric stations which have been prescribed for rate regulation, effective July 1, 2014, under amended *Ontario Regulation 53/05*. The comparative information for the 48 hydroelectric stations, previously recorded under the Unregulated – Hydroelectric segment in OPG's first quarter 2013 MD&A and financial statements, has been reclassified to conform to this new presentation.

The Contracted Generation Portfolio segment includes the results of operating generation facilities that are not prescribed for rate regulation. The segment includes primarily generating facilities that are under an Energy Supply Agreement or other long-term generating contract with the Ontario Power Authority (OPA).

Activities of generating stations that are not currently subject to a contract or rate regulation, but are available to generate electricity for sale, if required, are also included in the Contracted Generation Portfolio segment. Since the Lambton GS and Nanticoke GS were generating electricity up to the end of 2013, the activities related to these stations for the comparative period are reported in the Contracted Generation Portfolio segment. Effective January 1, 2014, the activities related to the Lambton GS and Nanticoke GS are reported under the Services, Trading, and other Non-Generation business segment. These stations ended coal-fired operations as a result of the Shareholder declaration issued in March 2013 mandating that OPG end the use of coal at these stations by the end of 2013.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in Portlands Energy Centre (PEC) and Brighton Beach. OPG's share of the in-service generating capacity and generation volume from its interests in PEC and Brighton Beach are also included in this segment.

The Services, Trading, and other Non-Generation segment is a non-generation segment and includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, sales of financial risk management products, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the US market. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in the revenue of this segment. In addition, this segment includes revenue from real estate rentals and other unregulated service revenues. The above activities were previously reported in the other segment.

Information for the comparative period has been adjusted to reflect the changes to OPG's reportable business segments and is labeled "adjusted".

Segment (Loss) Income for the Three Months Ended June 30, 2014 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydroelectric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and other Non-Generation	Elimination	Total
Revenue	**683**	**29**	**316**	**64**	**34**	**(28)**	**1,098**
Fuel expense	**56**	**-**	**87**	**11**	**-**	**-**	**154**
Gross margin	**627**	**29**	**229**	**53**	**34**	**(28)**	**944**
Operations, maintenance and administration	**502**	**31**	**85**	**43**	**33**	**(28)**	**666**
Depreciation and amortization	**129**	**-**	**41**	**6**	**5**	**-**	**181**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**191**	**-**	**2**	**2**	**-**	**195**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(217)**	**-**	**-**	**-**	**-**	**(217)**
Property and capital taxes	**7**	**-**	**-**	**(4)**	**(4)**	**-**	**(1)**
Income from investments subject to significant influence	**-**	**-**	**-**	**(10)**	**-**	**-**	**(10)**
Restructuring	**-**	**-**	**-**	**7**	**3**	**-**	**10**
Other loss	**-**	**-**	**1**	**-**	**-**	**-**	**1**
(Loss) income before interest and income taxes	**(11)**	**24**	**102**	**9**	**(5)**	**-**	**119**

Segment Income (Loss) for the Three Months Ended June 30, 2013 *(millions of dollars)* *(adjusted)*	**Regulated**		**Unregulated**				
	Nuclear Generation	**Nuclear Waste Manage-ment**	**Hydro-electric**	**Contracted Generation Portfolio**	**Services, Trading, and other Non-Generation**	**Elimination**	**Total**
Revenue	697	28	320	152	20	(27)	1,190
Fuel expense	57	-	90	25	-	-	172
Gross margin	640	28	230	127	20	(27)	1,018
Operations, maintenance and administration	463	30	68	108	1	(27)	643
Depreciation and amortization	155	-	46	36	5	-	242
Accretion on fixed asset removal and nuclear waste management liabilities	-	186	-	3	1	-	190
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(173)	-	-	-	-	(173)
Property and capital taxes	8	-	-	3	3	-	14
Income from investments subject to significant influence	-	-	-	(9)	-	-	(9)
Other income	(1)	-	-	(1)	(2)	-	(4)
Income (loss) before interest and income taxes	15	(15)	116	(13)	12	-	115

Segment (Loss) Income for the Six Months Ended June 30, 2014 *(millions of dollars)*	Regulated		Unregulated				
	Nuclear Generation	Nuclear Waste Manage-ment	Hydro-electric	Contracted Generation Portfolio	Services, Trading, and other Non-Generation	Elimination	Total
Revenue	**1,391**	**58**	**812**	**157**	**123**	**(56)**	**2,485**
Fuel expense	**116**	**-**	**158**	**27**	**2**	**-**	**303**
Gross margin	**1,275**	**58**	**654**	**130**	**121**	**(56)**	**2,182**
Operations, maintenance and administration	**1,013**	**62**	**161**	**86**	**70**	**(56)**	**1,336**
Depreciation and amortization	**259**	**-**	**82**	**11**	**10**	**-**	**362**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**383**	**-**	**4**	**4**	**-**	**391**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(377)**	**-**	**-**	**-**	**-**	**(377)**
Property and capital taxes	**14**	**-**	**-**	**(3)**	**(1)**	**-**	**10**
Income from investments subject to significant influence	**-**	**-**	**-**	**(23)**	**-**	**-**	**(23)**
Restructuring	**-**	**-**	**-**	**7**	**5**	**-**	**12**
Other loss	**-**	**-**	**2**	**-**	**-**	**-**	**2**
(Loss) income before interest and income taxes	**(11)**	**(10)**	**409**	**48**	**33**	**-**	**469**

Segment (Loss) Income for the Six Months Ended June 30, 2013 *(millions of dollars)* *(adjusted)*	Regulated		Unregulated				
	Nuclear Generation	**Nuclear Waste Manage-ment**	**Hydro-electric**	**Contracted Generation Portfolio**	**Services, Trading, and other Non-Generation**	**Elimination**	**Total**
Revenue	1,432	53	637	334	40	(51)	2,445
Fuel expense	119	-	160	76	-	-	355
Gross margin	1,313	53	477	258	40	(51)	2,090
Operations, maintenance and administration	990	57	141	204	2	(51)	1,343
Depreciation and amortization	311	-	92	71	10	-	484
Accretion on fixed asset removal and nuclear waste management liabilities	-	371	-	7	1	-	379
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(297)	-	-	-	-	(297)
Property and capital taxes	15	-	1	7	6	-	29
Income from investments subject to significant influence	-	-	-	(19)	-	-	(19)
Restructuring	-	-	-	2	-	-	2
Other loss (income)	(1)	-	2	(2)	(2)	-	(3)
(Loss) Income before interest and income taxes	(2)	(78)	241	(12)	23	-	172

Selected Consolidated Balance Sheet Information as at June 30, 2014 *(millions of dollars)*	**Nuclear Generation**	**Regulated Nuclear Waste Manage-ment**	**Hydro-electric**	**Unregulated Contracted Generation Portfolio**	**Services, Trading, and other Non-Generation**	**Total**
Segment property, plant and equipment in-service, net	**4,718**	**-**	**7,573**	**1,366**	**339**	**13,996**
Segment construction in progress	**1,254**	**-**	**94**	**1,786**	**48**	**3,182**
Segment property, plant and equipment, net	**5,972**	**-**	**7,667**	**3,152**	**387**	**17,178**
Segment intangible assets in-service, net	**14**	**-**	**1**	**4**	**17**	**36**
Segment development in progress	**-**	**-**	**-**	**-**	**32**	**32**
Segment intangible assets, net	**14**	**-**	**1**	**4**	**49**	**68**
Segment materials and supplies inventory, net:						
Current	**94**	**-**	**-**	**-**	**-**	**94**
Long-term	**330**	**-**	**1**	**6**	**-**	**337**
Segment fuel inventory	**326**	**-**	**-**	**40**	**-**	**366**
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	**-**	**13,986**	**-**	**-**	**-**	**13,986**
Fixed asset removal and nuclear waste management liabilities	**-**	**(16,288)**	**-**	**(328)**	**(32)**	**(16,648)**

Selected Consolidated Balance Sheet Information as at December 31, 2013 *(millions of dollars)* *(adjusted)*	**Nuclear Generation**	**Regulated Nuclear Waste Manage-ment**	**Hydro-electric**	**Unregulated Contracted Generation Portfolio**	**Unregulated Services, Trading, and other Non-Generation**	**Total**
Segment property, plant and equipment in-service, net	4,864	-	7,624	921	189	13,598
Segment construction in progress	866	-	81	2,150	43	3,140
Segment property, plant and equipment, net	5,730	-	7,705	3,071	232	16,738
Segment intangible assets in-service, net	15	-	1	4	17	37
Segment development in progress	2	-	-	-	20	22
Segment intangible assets, net	17	-	1	4	37	59
Segment materials and supplies inventory, net:						
Current	94	-	-	1	-	95
Long-term	322	-	1	7	-	330
Segment fuel inventory	334	-	-	56	-	390
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	13,496	-	-	-	13,496
Fixed asset removal and nuclear waste management liabilities	-	(15,903)	-	(322)	(32)	(16,257)

13. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	**Six Months Ended June 30 2014**	**Six Months Ended June 30 2013**
Receivables from related parties	**38**	47
Other accounts receivable and prepaid expenses	**(22)**	(38)
Fuel inventory	**24**	42
Income taxes payable	**77**	24
Materials and supplies	**1**	(7)
Accounts payable and accrued charges	**(131)**	(49)
	(13)	19

14. RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province, the OPA and the other successor entities of Ontario Hydro, including Hydro One Inc. (Hydro One), the IESO, and the OEFC. Related parties also include OPG's jointly controlled entities. The transactions between OPG and the related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

The related party balances, as at June 30, 2014 and December 31, 2013, are summarized below:

(millions of dollars)	**2014**	**2013**
Receivables from related parties		
Hydro One	**1**	2
IESO	**330**	317
OEFC	**14**	67
OPA	**17**	14
PEC	**2**	2
Accounts payable and accrued charges		
Hydro One	**4**	3
OEFC	**50**	51
Province	**3**	2

15. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE

Investments subject to significant influence consist of OPG's 50 percent ownership interest in the jointly controlled entities of PEC and Brighton Beach, which are accounted for using the equity method. Details of the balances as at June 30, 2014 and December 31, 2013 are as follows:

(millions of dollars)	**2014**	**2013**
PEC		
Current assets	**17**	19
Long-term assets	**295**	303
Current liabilities	**(8)**	(15)
Long-term liabilities	**(4)**	(4)
Brighton Beach		
Current assets	**5**	5
Long-term assets	**191**	196
Current liabilities	**(12)**	(11)
Long-term liabilities	**(6)**	(5)
Long-term debt	**(124)**	(129)
Investments subject to significant influence	**354**	359

16. RESTRUCTURING

In response to the Ministry of Energy's Long-Term Energy Plan, Supply Mix Directive and various other directives, OPG has been undertaking restructuring activities since 2011 pertaining to the closure of its coal-fired generating units at the Lambton GS, Nanticoke GS, Atikokan GS and Thunder Bay GS. These activities have an impact on staff requirements and require OPG to record the corresponding restructuring costs.

In December 2013, the Minister of Energy issued a Directive to the OPA to negotiate and enter into a contract for electricity from one unit at the Thunder Bay GS using advanced biomass fuel. The impact on staff requirements has been finalized. The total restructuring costs, exclusively severance costs, are estimated to be $7 million and were recorded during the second quarter of 2014. Relocation costs are expected to be minimal and will be recorded as incurred, primarily in 2015.

OPG conducted discussions with key stakeholders, including The Society and the PWU, in accordance with their respective collective bargaining agreements, at all plants impacted to date by the regulation requiring the cessation of coal-fired electricity generation. Given collective agreement provisions allowing deferral of severance payout to future periods, the restructuring liability is expected to be fully drawn down by 2017.

The change in the restructuring liability for severance costs for the six months ended June 30, 2014 and for the year ended December 31, 2013 is as follows:

(millions of dollars)	
Liability, January 1, 2013	3
Restructuring charges during the year	50
Payments during the year	(13)
Liability, December 31, 2013	40
Restructuring charges during the period	9
Payments during the period	(16)
Liability, June 30, 2014	**33**

17. NON-CONTROLLING INTEREST

Lower Mattagami Limited Partnership (LMLP) is an Ontario limited partnership between OPG, Amisk-oo-Skow Finance Corporation (AFC), a corporation wholly owned by the Moose Cree First Nation, and LM Extension Inc., a wholly owned subsidiary of OPG. The principal business of LMLP is the development, construction, ownership, operation and maintenance of hydroelectric generating facilities on the Lower Mattagami River. As incremental units are placed in-service, AFC may acquire up to a 25 percent interest in the value of the assets through its investment in LMLP.

The Little Long GS and Harmon GS are the first and second incremental units of the Lower Mattagami River project which were declared in-service in January 2014 and June 2014, respectively. Subsequent to the units' in-service dates, AFC acquired a 25 percent interest in the value of the incremental assets of the Lower Mattagami River project through its investment in LMLP and made equity contributions of $27 million and $26 million to LMLP in relation to the Little Long GS and the Harmon GS, respectively. The equity contribution for the Little Long GS was comprised of a long-term debt repayment of $21 million and repayment of $6 million representing other amounts owed by OPG. The equity contribution for the Harmon GS was comprised of a long-term debt repayment of $20 million and repayment of $6 million representing other amounts owed by OPG. For the three and six month periods ended June 30, 2014, LMLP distributed $1 million and $2 million, respectively, to AFC (three and six month periods ended June 30, 2013 – nil). The cumulative equity of AFC was $53 million as at June 30, 2014 (December 31, 2013 – nil). OPG consolidates the results of LMLP in its consolidated financial statements and the non-controlling interest represents AFC's ownership interest in LMLP.